- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

Application of Enbridge Gas Utah to Increase Distribution Rates and Charges and Make Tariff Modifications	DOCKET NO. 25-057-06 ORDER

ISSUED: December 24, 2025

SYNOPSIS

Phase I: Settlement Stipulation – Revenue Requirement

The Public Service Commission of Utah (PSC) issues this General Rate Case (GRC) order in the above-referenced docket brought by Enbridge Gas Utah (EGU). The PSC approves a settlement stipulation addressing the Phase I issues in this docket as explained below (the "Phase I Stipulation"). The Phase I Stipulation is unopposed and reflects a black box agreement among the settling parties ("Settling Parties")[1] and addresses certain issues.

First, the Settling Parties stipulate to a total revenue requirement of $604 million based on an average test period ending December 31, 2026. This represents an increase of approximately $60.2 million.[2]

Second, the Settling Parties stipulate that the $604 million revenue requirement does not include the acceptance or rejection of any adjustment recommended by any party and does not authorize or use any particular rate of return on equity, cost of capital, or any revenue requirement items that may be included or excluded from the total revenue requirement.[3]

Third, the Settling Parties stipulate to depreciation rates that are based on EGU's depreciation study filed in this docket, as modified by the proposals in the "Phase I Written Direct Testimony of [OCS] witness David Garrett."[4]

Fourth, the Settling Parties stipulate to allow EGU to continue to use the previously authorized rate of return (approved in Docket No. 22-057-03 and reflected in EGU's Natural Gas Tariff No. 700 ("Tariff")) only in the limited cases of: (1) as an input to calculate the pretax rate of return specifically referenced in EGU's existing Infrastructure Rate Adjustment (IRA) Tracker and Rural Expansion Rate Adjustment (RERA) Tracker tariffs; and (2) the rate of return applied to the Wexpro II Agreement,

[1] These parties are Enbridge Gas Utah (EGU), the Division of Public Utilities (DPU), the Office of Consumer Services ("OCS"), and the Utah Association of Energy Users ("UAE").
[2] The incremental revenue requirement is based on the billing determinants and load adjustment recommended by UAE in Phase II of this docket, and approved by the PSC, as discussed in detail in Section IV.B.8.b., *infra*.
[3] *See* Phase I Stipulation at 3-4, ¶ 11.
[4] *See* Phase I Stipulation at 4, ¶ 12 (referencing the Phase I Dir. Test. of David Garrett, Part II for the OCS (August 26, 2025)). *See also* Phase I Stipulation, Exhibit 1.

and in future PSC proceedings requiring the use of a PSC-authorized rate of return in calculating costs or rates that result in orders issued before the effective date of the next GRC.[5]

Fifth, the Settling Parties stipulate to the continuation of the RERA Tracker addressed in Section 9.02 of EGU's Tariff as set forth in the Tariff in effect as of the date of the Phase I Stipulation.

Sixth, the Settling Parties stipulate that in EGU's next replacement infrastructure annual plan and budget docket, EGU will provide a detailed overview of how it selects projects for the replacement program, and updated estimates of the life of the IRA Tracker Program.

Seventh, the Settling Parties stipulate that any issues raised by any party relating to the Phase II issues identified in footnote 1 of the Phase I Stipulation are not foreclosed by the Phase I Stipulation.

Phase II: Cost Allocation and Rate Design

We allocate the revenue increase to customer classes to improve alignment of revenue requirement with the costs to service each customer class, except for the Transportation Bypass Firm (TBF) customer class, resulting in non-uniform percentage increases to the rate schedules.

The rates and charges reflecting the decisions in this order are presented in Table 3 and Table 4 of this order. The total increase for all customer classes will be implemented, effective January 1, 2026.

We approve certain rate design proposals, and deny others. We approve continuation of the Conservation Enabling Tariff, subject to specific conditions and our further direction; we approve maintaining the declining block structure for TS customers, as ordered in the 2022 GRC; we approve a low pressure surcharge for customers receiving gas through intermediate high pressure mains; we approve UAE's request to align the cost allocation for the TBF class with the billing determinants used to design TBF rates, which results in a reduction to the overall revenue deficiency associated with the Phase I Stipulation from approximately $62 million to approximately $60.2 million; we approve various Tariff-related issues; and we approve

[5] When asked at hearing what other future dockets beyond the trackers and Wexpro might qualify for this treatment, EGU witness Summers said: "I'm not aware of anything else that would have that number applied to it for … purposes of ratemaking." Oct. 22, 2025 Hr'g Tr. at 44:15-17 and 44:23-45:13.

EGU's requested monthly fixed charges, including EGU's request to maintain the Basic Service Fee charges currently in effect.

We deny EGU's request to calculate Normal Heating Degree Days using a 10-year timeframe, but instead approve use of a 15-year timeframe; we deny EGU's request for a subsidy to support the NGV class; and we deny DPU's request for the formation of a working group to study the TS class and the Transportation Imbalance Charge.

We also order certain studies and other actions. We order EGU to conduct a study and present a report to the PSC by the end of 2026 on certain issues relating to telemetry equipment; we order EGU to file with the PSC within 30 days from the date of this order certain information relating to TBF class customers; and we also temporarily close the TBF class to any new customers pending additional study on the impact of new large load customers, including new large data centers, potentially seeking service on the discounted TBF rate schedule, which study shall be completed no later than the end of 2026.

Finally, we will establish an investigatory proceeding in a new docket concerning the possibility of splitting the GS class in a future GRC.

Table of Contents

APPEARANCES

Jenniffer Nelson Clark, Esq. *Enbridge Gas Utah* Anne W. Mitchell Ronit Barrett, Esq. *Whitt Sturtevant*	For	Enbridge Gas Utah
Patricia E. Schmid, Esq. Patrick Grecu, Esq. *Utah Attorney General's Office*	"	Division of Public Utilities
Robert Moore, Esq. Steven W. Snarr, Esq. *Utah Attorney General's Office*	"	Office of Consumer Services
Phillip J. Russell, Esq. *James Dodge Russell & Stephens, P.C.*	"	Utah Association of Energy Users
Captain Michael Rivera, Esq. Major Leslie R. Newton, Esq. *United States Air Force*	"	Federal Executive Agencies
Jeremy R. Cook, Esq. *Cohne Kinghorn* Laura W. Baker, Esq. Damon E. Xenopoulos, Esq. *Stone Mattheis Xenopoulos & Brew, P.C.*	"	Nucor Steel-Utah
Mark A. Davidson, Esq. *Fairfield and Woods, P.C.*	"	American Natural Gas Council

I. INTRODUCTION

This matter is before the PSC on EGU's May 1, 2025, verified application requesting authority to increase its DNG retail rates by approximately $114.7[6] million, or 21.2 percent[7] ("Application"), and to implement new rates, effective January 1, 2026.

The Application is based on the forecast test year ending December 31, 2026 ("Test Year"), a 13-month average rate base with an historical base period, and a requested return on common equity ("ROE") of 10.6 percent. EGU proposes bringing all rate classes to full cost of service, except for the TBF and NGV classes. EGU proposes (1) using the same rate design the PSC approved in EGU's last general rate case, and (2) making other changes, both substantive and non-substantive, to its Tariff. EGU also proposes to continue the IRA Tracker at currently approved 2024 spending amounts of $86.7 million, adjusted annually using the GDP Deflator, and that the threshold be set at $96.0 million. EGU proposes that IRA costs be tracked beginning January 1, 2025, with any costs exceeding the IRA threshold allowed to be recovered through the IRA Tracker. Similarly, EGU further proposes to include in rate base $17.2 million of related costs for rural expansions under EGU's RERA Tracker mechanism. EGU proposes that $17.2 million be used as a threshold and that RERA

---

[6] EGU subsequently provided a revised version of its rate case model in response to discovery, correcting numerous errors in its filed case, resulting in a revised rate case model indicating a Utah DNG revenue deficiency of $117.9 million.
[7] *See* Direct Test. of A. Summers filed May 1, 2025, EGU Exhibit 5.14 – Electronic Model, "Report" tab (hereafter, "A. Summers Direct Test.").

costs be tracked beginning January 1, 2025, and any costs exceeding the RERA threshold be allowed to be recovered through the RERA Tracker.

II. PROCEDURAL HISTORY

On May 1, 2025, EGU filed the Application, including supporting direct testimony and exhibits. On May 2, 2025, the PSC issued a notice of virtual scheduling conference to be held on May 9, 2025.[8]

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

On May 13, 2025, the PSC issued a scheduling order, notice of technical conferences, notice of public witness hearings, and notice of hearings, setting the schedule for this docket. The scheduling order specified a bifurcated schedule: Phase I addressed EGU's cost of capital, revenue requirement, return on equity, and depreciation study; Phase II addressed cost of service for each customer class, rate design, and EGU's other proposed tariff changes.

A. Phase I – Revenue Requirement

On August 26, 2025, DPU, OCS, FEA, and UAE each filed Phase I direct testimony. On September 18, 2025, EGU filed an Unopposed Motion to Amend Scheduling Order, requesting an extension of the deadline for the Phase I written

---

[8] On May 5 and 6, 2025, EGU filed "Revised EGU Exhibit 4.17" and "Revised Exhibit 7.0 - Direct Testimony of Jordan Parks," respectively.

rebuttal testimony to facilitate ongoing settlement discussions. That motion was granted on September 19, 2025.

On September 26, 2025, the Settling Parties filed a Phase I Settlement Stipulation ("Phase I Stipulation").[9] Because the Phase I Stipulation reflects a so-called "black box"[10] settlement, on October 1, 2025, the PSC issued a notice requesting the Settling Parties to submit written witness testimony providing an analysis substantiating the grounds for the PSC's approval of the terms of the Phase I Stipulation ("PSC Notice"). The Settling Parties filed responsive testimony on October 15, 2025 ("Phase I Stipulation Written Testimony").

The PSC conducted an evidentiary hearing on the Phase I Stipulation on October 22, 2025 ("Phase I Hearing"), and held public witness hearings in St. George, Vernal, and Salt Lake City, Utah on October 16, 20, and 22, 2025, respectively.

B. Phase II – Class Cost of Service, Rate Design

On September 16, 2025, DPU, OCS, UAE, Nucor, FEA, and ANGC filed Phase II direct testimony. On October 16, 2025, EGU, DPU, OCS, UAE, Nucor, FEA, and ANGC filed Phase II rebuttal testimony. On November 4, 2025, EGU, DPU, OCS, UAE, Nucor, FEA, and ANGC filed Phase II surrebuttal testimony. The PSC conducted evidentiary hearings on Phase II issues on November 18 and 19, 2025 ("Phase II Hearing"), and held a public witness hearing in Salt Lake City, Utah on November 18, 2025.

---

[9] FEA, ANGC, and Nucor were not signatories to the Phase I Stipulation, but did not oppose it.
[10] This is further explained below.

III. PHASE I: REVENUE REQUIREMENT SETTLEMENT STIPULATION

In the Phase I Stipulation, the Settling Parties agreed to a total revenue requirement of $604 million based on the Test Year.[11] The Phase I Stipulation is unopposed. As a "black box" settlement, the Phase I Stipulation states the "total revenue requirement of $604 million does not include acceptance or rejection of any recommended adjustment and does not specify any particular cost of capital or any revenue requirement items that may be included or excluded from the total revenue requirement."[12] Additionally, the Phase I Stipulation provides, "[t]his stipulation does not resolve Phase II arguments concerning billing determinants and their effect on current revenues and the revenue requirement deficiency. Therefore, the stipulation is limited to a total revenue requirement amount rather than to any revenue requirement increase."[13]

In addition to the revenue requirement, the Phase I Stipulation specifically resolves the following additional issues:

---

[11] *See* Phase I Stipulation at 3, ¶ 10. This is a reduction of approximately $52.5 million from the $656,644,957 amount originally sought by EGU in the Application. *See* EGU Exhibit 4.02, line 3.
[12] Phase I Stipulation at 4, ¶ 11. Because of the Phase I Stipulation's silence on specific items like EGU's capital structure, its return on equity, and its cost of debt, these types of items as they relate to the "black box" concept were more fully explained by the Settling Parties in their respective Phase I Stipulation Written Testimony and at the Phase I Hearing.
[13] *Id.* at 3, n.1.

- Depreciation – new depreciation rates as modified by the proposals in the Phase I Written Direct Testimony of OCS witness David Garrett will be used by EGU.[14]
- Limited Use of Rate of Return in Tracker Programs and Agreements – EGU will use the PSC-authorized rate of return ("ROR") previously approved in the 2022 GRC (and reflected in Tariff No. 700) only in the limited cases of (1) as an input to calculate the pretax rate of return specifically referenced in EGU's existing IRA Tracker and RERA Tracker tariffs;[15] and (2) the rate of return applied to the Wexpro II Agreement, and in future PSC proceedings requiring the use of a PSC-authorized rate of return in calculating costs or rates that result in orders issued before the effective date of the next GRC.[16]
- Rural Expansion Tracker Program – the RERA Tracker addressed in Section 9.02 of the Tariff will be continued as of the date of the Phase I Stipulation.[17]
- Infrastructure Tracker – EGU will provide a detailed overview of how it selects projects for the infrastructure replacement program and updated estimates of the life of the IRA Tracker program in EGU's next replacement infrastructure annual plan and budget docket.[18]

---

[14] *See id.* at 4, ¶ 12.
[15] *Id.* at 4, ¶ 13. *See also* Phase I Hearing Transcript, Oct. 22, 2025 ("Oct. 22, 2025 Hr'g Tr.") at 24:10-22.
[16] Phase I Stipulation at 4-5, ¶ 13. *See also* Oct. 22, 2025 Hr'g Tr. at 42:24-45:3 (EGU witness unaware of anything other than the IRA Tracker, RERA Tracker, and Wexpro II Agreement to which ROR from the 2022 GRC would apply) and *id.* at 56:15-22 (DPU witness testifying similarly).
[17] Phase I Stipulation at 5, ¶ 14.
[18] *Id.* at 5, ¶ 15.

A. Phase I Stipulation Written Testimony

The Settling Parties filed Phase I Stipulation Written Testimony in response to the PSC Notice requesting their "*analysis supporting why* PSC approval of the terms of the Phase I [Stipulation] is (1) in the public interest, and (2) just and reasonable in result."[19] EGU, DPU, OCS, and UAE each filed Phase I Stipulation Written Testimony.

EGU Phase I Stipulation Written Testimony

EGU's written testimony highlights important facts providing greater context to the reasonableness of the Phase I Stipulation. For example, EGU's witness testified that "[t]he $62 million revenue requirement increase proposed in the [Phase I Stipulation] is slightly higher than the positions of the Settl[ing] Parties, but significantly lower than [EGU's] proposal[,]" and thus "demonstrates that the [Phase I Stipulation] is just and reasonable in result."[20] EGU's testimony also provides "a summary of the positions each of the Phase [I] Parties[21] proposed [in the Phase I proceedings] and the amount those adjustments would make to [EGU's] proposed revenue requirement[,]"[22] including adjustments to EGU's requested return on equity, capital structure, depreciation rates, and other items.[23] This summary shows a range of possible EGU revenue requirement increase outcomes based on the parties'

---

[19] PSC Notice at 2 (italics in original).
[20] EGU Phase I Stipulation Written Testimony at 3:79-4:82.
[21] EGU identifies these parties as DPU, UAE, OCS, and FEA. *See id.* at 3:64-66 (*citing* EGU Exhibit 8.01, provided with EGU's Phase I Stipulation Written Testimony).
[22] EGU Phase I Stipulation Written Testimony at 3:64-66.
[23] *See id.* at 3:67-72.

respective proposed adjustments, and confirms the $62 million revenue requirement increase proposed in the Phase I Stipulation is higher than the positions of the Settling Parties, but is significantly lower than EGU's proposed increase.[24]

Finally, EGU's witness testified that the PSC can conduct a reasonableness analysis "by examining all of the Parties' positions on the record[]and seeing where this black box settlement falls within the possible outcomes[,]"[25] and then use EGU's model to "apply the position of any [p]arty to see what [the] ultimate revenue deficiency would [be] … with a variety of applied" adjustments.[26] EGU testified that such an analysis will show "that the revenue deficiency reflected in the [Phase I Stipulation] falls well within the range of outcomes among the [p]arties and [EGU]."[27]

DPU Phase I Stipulation Written Testimony

DPU's written testimony also highlights facts supporting the reasonableness of the Phase I Stipulation. For example, DPU's written testimony provides an illustrative and hypothetical "range of Return on Equity (ROE) perspectives that might lead to the … revenue requirement" in the Phase I Stipulation.[28] This illustration is provided in a "chart show[ing] a range of ROEs from 9.0% to 9.68% with other adjustments for

[24] *See id.*, EGU Exhibit 8.01.
[25] EGU Phase I Stipulation Written Testimony at 4:87-89.
[26] *Id.* at 4:90-92.
[27] *Id.* at 4:93-95.
[28] DPU Phase I Stipulation Written Testimony at 7:171-72.

depreciation and additional items that could result in the … revenue requirement number[]"[29] in the Phase I Stipulation.[30]

DPU also testified about its statutory mandate as a party to this docket, stating Utah law requires it "to maintain the financial integrity of the utility, promote efficient management and operation of the utility, protect the long-range interest of consumers, provide for fair apportionment of the total cost of service among customer categories, and promote stability in rate levels for customers and the revenue requirement for the utility."[31] In fulfilling these requirements, DPU testified it engaged in extensive analysis of the parties' respective positions in Phase I of this docket and based on that analysis, "determined that the [Phase I] Stipulation, taken as a whole, was just and reasonable[,] … [and that its] terms and conditions … would result in just and reasonable rates for Utah customers."[32] Based on this determination, DPU recommended approval of the Phase I Stipulation as "the proposed rates are just and reasonable in result and are therefore in the public interest."[33]

---

[29] *Id.* at 7:172-8:74.
[30] In response to a question from Commissioner Harvey regarding the implied rate of return on equity, DPU witness Eric Orton replied that if the PSC did not accept any of the parties' adjustments, beyond the depreciation changes incorporated into the stipulation, the rate of return on equity implied by the stipulation would be approximately 8.8 percent. *See* Oct. 22, 2025 Hr'g Tr. at 55:4-56:13.
[31] DPU Phase I Stipulation Written Testimony at 4:87-91.
[32] *Id.* at 9:216-18.
[33] *Id.* at 9:220-21.

OCS Phase I Stipulation Written Testimony

OCS's written testimony provides an overview of various provisions in the Phase I Stipulation and expressed support for its approval. OCS's testimony states that OCS assessed "the relative strengths and weaknesses of the various potential adjustments [at issue in Phase I of this docket] to determine … the range of reasonable and likely outcomes for the total revenue requirement in this case."[34] Based on this assessment, OCS testified that "[t]he revenue requirement number [proposed in the Phase I Stipulation] was within [OCS's] assessment of the range of reasonable and likely outcomes[,]"[35] and OCS therefore determined that "a revenue requirement that fell into [the] range of what [it] considered reasonable would be in the public interest as well as just and reasonable in result."[36] OCS also testified that "the settled upon total revenue requirement is quite close to the revenue requirement that would result solely from the use of the limited adjustments put forth by the OCS in this case."[37]

UAE Phase I Stipulation Written Testimony

UAE's written testimony also highlights important facts providing greater context to the reasonableness of the Phase I Stipulation. For example, UAE's witness testified that the revenue deficiency number in the Phase I Stipulation is approximately 47 percent less than EGU seeks in this docket,[38] resulting in a revenue

[34] OCS Phase I Stipulation Written Testimony at 5:118-22.
[35] *Id.* at 5:122-23.
[36] *Id.* at 5:123-6:126.
[37] *Id.* at 5:110-12.
[38] *See* UAE Phase I Stipulation Written Testimony at 2:30-31.

increase of only $62 million, as opposed to the $117.9 million[39] EGU seeks. UAE also testified that the Phase I Stipulation "is the product of principled negotiation and compromise[,]" and its approval "will result in a revenue requirement that is just, reasonable, and in the public interest."[40]

B. Testimony at Phase I Hearing

EGU's witness testified in support of the Phase I Stipulation, offering details on specific provisions. For example, EGU explained that, other than the IRA Tracker, RERA Tracker, and Wexpro II programs, the Phase I Stipulation does not identify or require any specific cost of capital, but that EGU's return on its capital expenditures will be lower than it sought in the Application.[41] EGU further explained that "if [EGU] manages its costs well, its expenses, then it might be able to earn a higher return … on its investments [than the approved ROR in the 2022 GRC]. If it does not manage well, then [EGU is] probably going to earn a lower return on its … investments."[42]

EGU also testified that the Phase I Stipulation does not foreclose any Phase II issues. On this point, EGU acknowledged its risk that, based on a proposal of UAE relating to a Phase II-related issue, EGU's revenue requirement increase could be reduced from $62 million to approximately $60.2 million after Phase II in this docket.[43]

---

[39] See n.6, *supra* (explaining EGU's revised version of its rate case model was to correct errors in its filed case, resulting in a revised rate case model indicating a Utah DNG revenue deficiency of $117.9 million).
[40] UAE Phase I Stipulation Written Testimony at 5:83-86.
[41] *See* Oct. 22, 2025 Hr'g Tr. at 34:9-17 & 40:24-41:8.
[42] *Id.* at 28:9-12.
[43] *See id.* at 33:14-34:8.

Finally, EGU concluded the Phase I Stipulation is in the public interest and is just and reasonable in result.

DPU's witness testified it "carried out an extensive investigation and analysis of [EGU's] revenues and expenses presented in this case, [and] conducted considerable discovery to obtain the needed information[]"[44] to reach its conclusion that the Phase I Stipulation is just and reasonable in result and its approval is in the public interest.[45] DPU also testified about various aspects of the Phase I Stipulation, including that it resulted from arm's length negotiations.

OCS's witness testified that the Phase I Stipulation is just and reasonable in result, and in the public interest. OCS also testified that the Phase I Stipulation should not be "deemed precedential with respect to how cost of capital or other revenue requirement issues are considered in the future."[46]

UAE's witness testified it reviewed the Phase I Stipulation, participated in settlement negotiations, and that it is just and reasonable in result, and in the public interest. UAE also provided testimony on various provisions of the Phase I Stipulation, including that it "only specifies a stipulated revenue requirement. It does not include acceptance or rejection of any recommended adjustments or cost of capital."[47] UAE further testified that the Phase I Stipulation does not resolve Phase II-related

[44] *Id.* at 51:5-8.
[45] *See id.* at 51:11-21.
[46] *Id.* at 62:4-6.
[47] *Id.* at 72:5-8.

arguments concerning billing determinants and their effect on current revenues and EGU's revenue requirement deficiency. Specifically, citing footnote 1 of the Phase I Stipulation, UAE testified that if the PSC approves the Phase I Stipulation and also UAE's Phase II arguments on this point, EGU's current revenues would be adjusted upward, and although the revenue requirement would remain, "the amount of the increase … needed to achieve that target revenue requirement would be reduced from $62 million to approximately $60.2 million[,]" resulting in a total reduction of $1.8 million.[48]

FEA's witness provided a brief overview of FEA's Phase I written direct testimony, specifically addressing its proposed ROR for EGU based on "a review of the utility's cost-effective ratemaking capital structure at a fair return on common equity."[49] FEA also confirmed it is not one of the Settling Parties and that it does not oppose the Phase I Stipulation.

At the conclusion of the Phase I Hearing, the PSC voiced its support for the Phase I Stipulation, approved it from the bench, and indicated its intent to affirm its ruling in a final written order.

---

[48] *Id.* at 72:22-24. *See also id.* at 72:16-18.
[49] *Id.* at 78:5-7.

C. Discussions, Findings, and Conclusions on the Phase I Stipulation

The Phase I Stipulation purports to settle all Phase I issues.[50] Our consideration of the Phase I Stipulation is governed by Utah Code § 54-7-1, which encourages informal resolution of matters before the PSC. The PSC may approve a settlement agreement after considering the interests of the public and other affected persons[51] if it finds the agreement is just and reasonable in result.[52] When reviewing a settlement involving a rate increase, the PSC may limit the factors and issues to be considered in its determination of just and reasonable rates.[53] In reviewing the Phase I Stipulation, the PSC may also consider whether it was the result of good faith, arm's length negotiations.[54]

The Settling Parties represent a diversity of interests who began discussing how to resolve their differences on September 16, 2025. The Settling Parties agree that the Phase I Stipulation is in the public interest and will produce a just and reasonable result. The non-signing parties also represent broad and diverse interests and, while they did not sign the Phase I Stipulation, they did not oppose it.

---

[50] Because of this, the PSC makes no ruling on any Phase I issues, other than with respect to the Phase I Stipulation. However, the Phase I Stipulation is inadequate relating to certain Phase I-related issues that are relevant to our Phase II decision making. For example, the Phase I Stipulation does not reflect any agreement on a final incremental Phase I DNG Revenue Requirement, nor does it provide a shared framework on the rate spread to be used for the incremental Phase I DNG revenue requirement. These omissions are addressed later in this order.

[51] *See* Utah Code Ann. § 54-7-1(2)(a).

[52] *See* Utah Code Ann. § 54-7-1(3)(d).

[53] *See* Utah Code Ann. § 54-7-1(4).

[54] *See Utah Dept. of Admin. Services v. Public Service Comm'n.,* 658 P.2d 601, 614 n.24 (Utah 1983).

Based on our consideration of the evidence before us, including the Application and exhibits, the written and live testimony of EGU, DPU, OCS, UAE, and FEA witnesses, the Phase I Stipulation, and the applicable legal standards, we find approval of the Phase I Stipulation is in the public interest and is just and reasonable in result. We further find the Phase I Stipulation is the product of good faith, arm's length negotiations conducted by parties representing a broad spectrum of customer interests. We conclude that substantial evidence of record relating to the Phase I Stipulation provides an appropriate basis upon which to establish just and reasonable rates, and we therefore approve the Phase I Stipulation.[55]

IV. PHASE II: COST ALLOCATION AND RATE DESIGN – DISCUSSION, FINDINGS, & CONCLUSIONS

A. Cost Allocation

1. Weighting of F230 Allocation Factor

EGU uses the F230 allocation factor ("F230 Factor") to allocate to its customer classes various revenue, expense, and rate base accounts. It is based on a weighting of 60 percent Design Day[56] and 40 percent Throughput.[57] This F230 Factor and

[55] Our approval does not, and is not intended to, alter existing PSC policy or establish PSC precedent. Instead, our approval simply acknowledges the reasonableness of the balance of the compromises reached by the Settling Parties in this docket.

[56] Design Day is an estimate of the gas on the system on a theoretical day when the mean temperature at the Salt Lake City Airport is -5 degrees Fahrenheit, which EGU states is a benchmark for designing and building its system and to plan the delivery of its service. *See* EGU's Integrated Resource Plan (IRP) for Plan Year: June 1, 2025 to May 31, 2026 for EGU's customer and gas demand forecast for the 2025-2026 plan year.

[57] Throughput is the total volume of gas moved through EGU's pipelines over a specific time. *See* EGU's Integrated Resource Plan for Plan Year: June 1, 2025 to May 31, 2026 for EGU's forecast system total throughput during the 2025-2026 IRP year.

percentage weighting were most recently approved in the 2022 GRC. Nucor, FEA, and UAE propose changes to the F230 Factor. Specifically, Nucor proposes 60 percent Design Day/40 percent Winter Throughput; FEA proposes a 60 percent Excess Demand/40 percent Throughput weighting; and UAE proposes a 66 percent Design Day/34 percent Throughput.[58]

Nucor proposes changing the throughput measure from annual throughput to winter month throughput.[59] While Nucor's proposal uses the same 60 percent/40 percent weighting, using only winter month throughput impacts the allocation of costs. FEA recommends replacing the F230 Factor methodology with a calculation of excess demand, asserting that the average demand (throughput) is counted twice in EGU's allocation calculation.[60] UAE proposes the use of the system load factor, about 34 percent, as an approximation for average throughput.[61] UAE thus proposes the F230 Factor change to a 66 percent Design Day/34 percent Throughput.

While DPU endorses EGU's current use of the 60 percent Design Day/40 percent Throughput allocation factor, it recommends calculating the system load factor using

---

[58] After reviewing UAE's recommendations for the use of a 66 percent Design Day/34 percent Throughput weighting, DPU recommends the use of Actual Peak instead of Design Day, if the PSC is inclined to use the F230 Factor weighting (based on the use of the system load factor) recommended by UAE. *See* Phase II Rebuttal Test. of M. Pernichele filed Oct. 16, 2025 at 6:128-31 (hereafter, "M. Pernichele Phase II Rebuttal Test.").
[59] *See* Phase II Direct Test. of L. Kaufman filed Sept. 16, 2025 at 3:57-58 (hereafter, "L. Kaufman Phase II Direct Test.").
[60] *See* Phase II Direct Test. of M. Smith filed Sept. 16, 2025 at 16:271-76 (hereafter, "M. Smith Phase II Direct Test.").
[61] *See* Phase II Direct Test. of C. Higgins filed Sept. 16, 2025 at 18:302-04 (hereafter, "C. Higgins Phase II Direct Test.").

actual historical peak data (Actual Peak),[62] instead of a hypothetical day (Design Day).[63] DPU "advocates for calculating the weights of throughput and demand using the Average and Peak method discussed in the NARUC manual using a load factor based on a rolling three-year average of Actual Peak Day usage."[64] DPU explains that it did not make this recommendation in direct testimony because of the PSC's long history of support for EGU's current methodology. DPU supports its recommendation by explaining that Design Day ignores other benefits provided by system capacity over an average day's usage. For example, DPU testified that excess capacity on the system allows additional new customers to use the system, and this spreads out system costs over larger volumes and lowers costs for all customers.

EGU asserts it allocated costs in this docket using the same allocation factors it has used for the past 20 years, and its approach is longstanding and has resulted in consistent rates.[65] EGU highlights that the significant difference in results from the parties' recommendations reveals and underscores the reasonableness of its proposal.[66]

We find the evidence supports that the 60 percent Design Day/40 percent Throughput weighting is consistent with historical practice and addresses the need for

---

[62] Actual Peak Day is the actual amount of gas on the system on the highest send-out day of the year, during a calendar year or heating season. *See* M. Pernichele Phase II Rebuttal Test. at 2:25-26.
[63] *See id*. at 2:45-3:49.
[64] *Id.* at 6:128-31.
[65] *See* Phase II Rebuttal Test. of A. Summers filed Oct. 16, 2025 at 12:220-24 (hereafter, "A. Summers Phase II Rebuttal Test.").
[66] *See id.* at 4:83-87.

facilities subject to the F230 Factor to both meet Design Day requirements and account for a normal Throughput and the expected growth on the system from which all EGU customers benefit. We also find that the evidence shows that the parties' differing recommended approaches result in widely different cost of service results. Therefore, we conclude it is in the public interest and just and reasonable in result to approve EGU's continued use of the F230 Factor and percentage weighting.

We further find that no party directly recommended a change to EGU's current practice to exclude Interruptible Service (IS) customers from the allocation of any Design Day costs,[67] and that UAE, FEA, and Nucor testified in support of EGU's current practice. Therefore, we conclude it is in the public interest and just and reasonable in result to continue to affirm EGU's practice to exclude IS customers from any Design Day costs allocation given the system is designed to meet the demands of firm customers.

2. Feeder Mains, Compressor Stations, and Measuring and Regulation Stations

EGU allocates feeder mains, compressor stations, and measuring and regulation stations using the F230 Factor, consistent with the methodology the PSC approved in the 2022 GRC and EGU's 2019 GRC. Specifically, EGU allocates 60 percent of the cost of feeder lines and other core assets using the Design Day allocator, while

[67] DPU's proposal to use Actual Peak Day values in calculating the F230 Factor would include IS customers' load in the calculation, at least some of the time.

the other 40 percent is allocated using a normal throughput allocator.[68] The parties' various recommended approaches and changes to the F230 Factor, as we describe above, would likewise impact the allocation of costs for feeder mains, compressor stations, and measuring and regulation stations.

For the same reasons set forth above, we find the evidence supports that EGU's continued use of the F230 Factor to allocate feeder mains, compressor stations, and measuring and regulation stations is reasonable and consistent with historical practice. The F230 Factor addresses the need for facilities subject to the F230 Factor to both meet Design Day requirements and account for normal Throughput and the growth of a system from which all EGU customers benefit. We therefore conclude it is in the public interest and just and reasonable in result to approve EGU's use of the F230 Factor to allocate costs for feeder mains, compressor stations, and measuring and regulation stations.

3. Large Diameter Mains

EGU allocates large diameter mains using the Distribution Throughput Factor.[69] EGU identifies customers that are not connected to the intermediate high pressure distribution system and then subtracts the Dths delivered to those customers from the commodity-throughput numbers. The facilities are sized for more than just local

---

[68] *See* A. Summers Phase II Rebuttal Test. at 2:38-40.
[69] *See id.* at 7:116-17.

delivery requirements and, therefore, are excluded from the Distribution Plant Factor Study.[70]

UAE, Nucor, and FEA propose changes to the allocation of large diameter mains. UAE proposes that the mains be allocated using 66 percent Distribution Design Day/34 percent Distribution Throughput. Nucor proposes a revenue-neutral change to the allocator since all but 10 of the 47 TSL customers are connected to the high-pressure feeder lines and do not use the large diameter mains.[71] FEA proposes the use of 60 percent Excess Design Day Demand/40 percent Throughput that it proposed for feeder mains, compressor stations, and regulation station equipment.[72]

EGU again highlights that these recommendations result in a significant change in the overall cost of service[73] process, which is based on longstanding practice. EGU asserts that neither UAE's nor Nucor's recommended alternative[74] is better than EGU's approach.[75] EGU further asserts that it has used the Distribution Throughput Factor to allocate large diameter mains costs for many years and neither UAE nor Nucor has offered a compelling reason to change this approach.[76]

[70] *See* A. Summers Direct Test. at 6:161-63.
[71] Nucor proposes a low-pressure surcharge on the 10 TSL customers which we address in our rate design discussion in Section IV.B. *infra*.
[72] *See* M. Smith Phase II Direct Test. at 21:360-63.
[73] *See* A. Summers Phase II Rebuttal Test. at 7:124-8:131.
[74] EGU did not address FEA's proposal for large diameter mains.
[75] *See id.* at 8:134-36.
[76] *See id.* at 8:136-38.

We find the evidence supports that use of the Distribution Throughput Factor is reasonable and consistent with historical practice. We are persuaded by EGU's argument that the facilities are sized for more than just local delivery requirements and, therefore, conclude they should be excluded from the Distribution Plant Factor Study.[77]

4. NGV Allocation Method

Only EGU and OCS make recommendations concerning the allocation of NGV subsidy costs. However, given the PSC's decision to decline approval of the NGV subsidy, as explained below, a ruling on the appropriate NGV allocation method is not necessary.

5. Allocation of Other Revenues and DNG Revenues

EGU allocates "other" or "miscellaneous" revenues in the Test Year, including capacity release revenues, interest on late payment fees, and rents of utility property using DNG Revenues, consistent with EGU's allocation of these revenues in recent cases.

OCS proposes a change to EGU's allocation of these costs. OCS argues that EGU incorrectly allocated certain "other" or "miscellaneous" revenues totaling $12,504,989 for the Test Year, including capacity release revenues, interest on late payment fees,

[77] A. Summers Direct Test. at 6:161-7:165.

the provision of rate refunds for EDIT amortization, and rents of utility property.[78] OCS asserts that these revenues are allocated to customer classes, and each class's cost of service is credited with its allocated amount, reducing revenue needed from that class's base rates.[79] Specifically, OCS disagrees with EGU's use of the "DNG Revenues" allocation factor for $4,130,103 in interest on past due accounts, claiming it disproportionately assigns these revenues to large customers who are typically not the source of past due accounts.[80] OCS argues that interest on past due accounts should be allocated to the customer classes that typically give rise to the past due accounts. OCS explains that using EGU's allocation factor based on the number of customers in the class is more appropriate.

EGU disagrees with OCS's proposal, asserting that not only is using DNG Revenue consistent with EGU's allocation in recent cases, but that OCS provided no evidence supporting its claim that large customers are not typically the source of past due accounts.[81] EGU also asserts that if OCS's proposal to allocate more revenues to small customers is accepted, it would also be appropriate to allocate more of the related expenses. UAE also recommends the PSC reject OCS's proposal, asserting there is no demonstrated "nexus between customer count and Interest on Past Due

---

[78] *See* Phase II Direct Test. of J. Daniel filed Sept. 16, 2025 at 5:111-17 (hereafter, "J. Daniel Phase II Direct Test.").
[79] *See id.* at 6:119-23.
[80] *See id.* at 6:124-30.
[81] *See* A. Summers Phase II Rebuttal Test. at 11:196-201.

Accounts, which is assessed as a percentage of past due bills and therefore varies with the amount of arrearages, not the number of customers."[82]

We find and conclude that the evidence supports EGU's use of the DNG Revenue to allocate "Other" or "Miscellaneous" revenues to be reasonable and consistent with historical practice. In addition, we find no evidence in the record showing that large customers are not typically the source of past due accounts.

6. Final Revenue Allocation

The Settling Parties agreed to a total revenue requirement of $604 million; however, an agreement on the final incremental Phase I DNG revenue requirement was not reached. In addition, the Settling Parties provided no shared framework on the rate spread for the PSC to use to determine the Phase I DNG incremental revenue requirement. Therefore, to determine Utah's jurisdictional incremental Phase I DNG revenue requirement, the PSC exercised its discretion and judgment in choosing the appropriate inputs from the evidence of record for this purpose.[83]

---

[82] *See* Phase II Rebuttal Test. of C. Higgins filed Oct. 16, 2025 at 9:135-37 (hereafter, "C. Higgins Phase II Rebuttal Test.").

[83] These include: (1) the currently allowed capital costs approved in the 2022 GRC; (2) the most recent state income tax rate of 4.5 percent, as proposed by DPU; (3) the stipulated depreciation rates, as agreed in the Phase I Stipulation; (4) the system revenue requirement adjustments proposed by DPU, including (a) Account 378 Measuring and Regulation Station Equipment, (b) Account 380 Services, (c) Account 363 LNG Plant – Land, (d) Account 394 Tools, Shop and Garage Equipment, (e) Short-Term Incentive Compensation, (f) Long-Term Incentive Compensation, (g) Payroll Tax, (h) Account 881 Rents, Office Space, (i) Account 880, Other Expenses, Storage Maintenance; (5) black box stipulation adjustment to Account 488 Miscellaneous Service Revenues using subaccount 488.004; (6) increase in the billing units of TBF for January-May 2026; and, (7) several minor corrections resulting in close to $4 million that were accepted by EGU, but were not made in EGU's Exhibit 5.16SR model that the PSC used in its inputs to the PSC's version of EGU's model.

In the absence of a Phase I DNG revenue requirement and rate spread agreement, the PSC concluded that many of DPU's revenue requirement adjustments proposed in Phase I were the most balanced, credible, and persuasive. The PSC found parties' proposals reflecting specific stakeholder interests carried less evidentiary weight than DPU's analysis. The PSC gave more weight to the relevant DPU adjustments based on DPU's statutory mandate to balance the interests of both the utility and its customers to promote the public interest.

Our allocation factor decisions above, coupled with the inputs we found necessary to use in the absence of a consensus on DNG revenue requirement and rate spread, result in the following revenue spread which we find just and reasonable and conclude to be in the public interest.

TABLE 1: REVENUE REQUIREMENT SPREAD, COST OF SERVICE ALLOCATION

	Forecast Revenues[84]	Full COS Change	Percent Change
GS	$473,032,124	$45,389,090	9.6%
FS	$3,648,957	$221,487	6.1%
IS	$194,645	$104,972	53.9%
TSS	$13,330,320	$3,777,651	28.3%
TSM	$17,536,991	$3,551,527	20.3%
TSL	$21,089,691	$3,719,365	17.6%
TBF	$11,083,146	$2,770,781	25.0%
NGV	$1,658,628	$650,501	39.2%

[84] Lake Side revenues are excluded. *See* EGU Exhibit 5.16SR, Tab AVG_Projected_REV_2026_adj_HDD (Cell T150 (DNG Revs for FTE-FT1L)). As a special contract, EGU excludes from its factor calculations gas throughput amounts because such contracts recover their costs of service and have already been found by the PSC to be just and reasonable during their approval in separate proceedings.

B. Rate Design

1. Conservation Enabling Tariff (CET)

a. Continuation of CET

EGU requests continuation of the CET. The CET was implemented in 2006 as a revenue decoupling mechanism (i.e., it adjusts revenue based on usage differences over time). Its continuation was most recently approved in the 2022 GRC. In support of its continuation, EGU testified that the CET ensures that EGU only collects the allowed revenue per customer, it helps eliminate the effects of forecasting error,[85] and it has returned $45 million to customers.[86] EGU also testified that the CET provides the benefit of revenue stability for both EGU and its customers.[87]

OCS recommends discontinuation of the CET. OCS testified that the original purpose of the CET has substantially diminished,[88] and that the CET primarily benefits EGU, not its customers.[89] DPU recommends the CET be continued, but with modifications and the adoption of certain safeguards. DPU testified that the CET has been overcollected since November 2022, reaching unprecedented levels.[90] DPU also testified that the CET has failed to self-correct. DPU proposes that the PSC adopt its recommendations to:

---

[85] *See* Direct Test. of K. Mendenhall filed May 1, 2025 at 19:407-20:418.
[86] *See id.* at 28:582-92.
[87] *See id.* at 29:596-608.
[88] *See* J. Daniel Phase II Direct Test. at 20:22-423.
[89] *See id.* at 15:328-30.
[90] *See* Phase II Direct Test. of R. Daigle filed Sept. 16, 2025 at 3:56-59 (hereafter, "R. Daigle Phase II Direct Test.").

(1) require EGU to make a CET filing to adjust the amortization rate as soon as the CET account balance is either over- or under-collected by $10 million, with similar required filings every six months until the CET account balance falls below the $10 million threshold;[91]

(2) require EGU to return to customers using EGU's 191 commodity balancing account any CET amount collected beyond the 5.0 percent of the allowed GS DNG revenues within 45 days of the month end closing;[92] and

(3) increase the amount EGU may amortize of CET accruals from 2.5 percent to 5.0 percent by amending Section 2.08 of EGU's Tariff.

In rebuttal testimony, EGU disputed both OCS's and DPU's arguments. EGU also testified, however, that in an effort to do a more thorough assessment of all of EGU's energy efficiency measures, including the CET, because of "the high level of interest and criticism of these programs in this docket," EGU will "request funds to conduct a third-party assessment of [these] programs[.]"[93]

At hearing, EGU testified that it opposes DPU's first proposal, the $10 million threshold filings proposal, asserting it is unnecessary because the Tariff already allows EGU to file a CET application multiple times per year and such a requirement could be administratively burdensome. EGU also testified that it opposes DPU's second proposal, the 45 day balancing account transfer proposal, asserting it does not provide a benefit because it would simply move the CET overcollection amount from one balancing account to another balancing account and thus, "if anything, [it would

---

[91] *See id.* at 8:149-52.
[92] *See id.* at 9:163-66.
[93] Phase II Rebuttal Test. of K. Mendenhall filed Oct. 16, 2025 at 8:163-9:165 (hereafter, "K. Mendenhall Phase II Rebuttal Test.").

result] in less transparency because now you're mixing CET revenue with commodity revenues [in these different balancing accounts]."[94] However, EGU testified that it agrees with DPU's third proposal, the increase in the amount EGU may amortize, and stated EGU "actually think[s] it's a more fair calculation than what we've had in the past."[95]

OCS testified that it recommended the PSC adopt DPU's proposal and agrees with EGU's proposal regarding conducting a third-party energy efficiency study.[96]

We find the evidence supports continuing the CET, but approve its continuation under the following conditions proposed by DPU: (1) EGU shall make a CET filing with the PSC when the CET balance exceeds or falls below a $10 million threshold, and continue to make semi-annual filings until the CET balance returns to within that threshold; and (2) the amortization limit set forth in Section 2.08 of the Tariff shall be increased from 2.5 percent to 5.0 percent of total Utah jurisdictional base DNG GS revenues, and EGU shall promptly file a conforming amendment to Section 2.08. We also find EGU's proposal to hire an independent third-party consultant to review the CET as part of a review of all of EGU's energy efficiency programs is reasonable and appropriate. We direct EGU to file the consultant's findings in a report with the PSC by the end of 2026.

---

[94] *See* Nov. 18, 2025 Hr'g Tr. at 111:21-112:23.
[95] *Id.* at 112:10-11.
[96] *See id.* at 242:21-243:2.

b. CET Revenue Per Customer

Based on our incremental Phase I DNG revenue requirement and revenue spread decisions in this order, we approve CET revenue per customer, per year of $425.98, as follows:

TABLE 2: ALLOWED CET REVENUE PER GS CUSTOMER

MONTH	TOTAL REVENUE	Allowed Revenue Per GS Customer
JAN	$86,172,523	$71.25
FEB	$72,520,298	$59.92
MAR	$59,928,974	$49.43
APR	$37,621,025	$30.98
MAY	$25,597,463	$21.06
JUN	$18,203,511	$14.95
JUL	$17,450,810	$14.33
AUG	$16,702,450	$13.70
SEP	$17,492,182	$14.32
OCT	$27,341,839	$22.39
NOV	$56,964,750	$46.52
DEC	$82,425,417	$67.13
	$518,421,242	$425.98

2. Weather Normalization Adjustment and Heating Degree Days

EGU proposes to calculate Normal Heating Degree Days (HDD) using a 10-year period ending December 31, 2024, effective January 1, 2026. The proposed annual HDD sum is 9 percent lower than the current 20-year HDD sum.[97] According to EGU, 78 percent of monthly weather normalization adjustments have been positive over the

[97] *See* Direct Test. of D. Landward filed May 1, 2025 at 3:49-50.

past 11 years, indicating warmer temperatures.[98] EGU also asserts that other utilities use a 10-year HDD period. EGU further asserts that readjusting 2023 and 2024 billed GS customer usage with the proposed 10-year HDD would have resulted in decreases of $11.2 million and $7.6 million, respectively.

DPU testified that EGU's empirical support for changing the HDD from a 20-year period to a 10-year period is marginal.[99] DPU further testified that EGU has not shown that the difference in average HDD values, 20-year versus 10-year, is statistically significant, and in the absence of a proper statistical test showing the difference is unlikely to have occurred by random chance, the apparent variance between the timeframes cannot be reliably used as evidence and undermines the weight of EGU's evidence.[100] DPU does not oppose a change of the HDD, but based on its analysis of EGU's statistical shortcomings recommends the PSC further study the issue.

OCS testified that reducing the HDD from a 20-year to a 10-year period is too drastic.[101] Similar to DPU, OCS asserts that EGU's evidence supporting its position is insufficient, claiming that a survey relied upon by EGU has an inadequate sample size and response rate, since only five out of a total of ten survey respondents used a 10-

---

[98] *See* Phase II Rebuttal Test. of D. Landward filed Oct. 16, 2025 at 4:74-76 (hereafter, "D. Landward Phase II Rebuttal Test.").
[99] *See* Phase II Surrebuttal Test. of D. Fields filed Nov. 4, 2025 at 5:93-96; *see also id.* at 3:61-62.
[100] *See* Nov. 18, 2025 Hr'g Tr. at 202:24-203:18.
[101] *See* J. Daniel Phase II Direct Test. at 10:223-24.

year average.[102] OCS further asserts that the other five respondents in the survey used 20-, 25-, and 30-year averages.[103] OCS acknowledges some inadequacies with EGU's current 20-year HDD period, so OCS proposes EGU adopt a 15-year average.

In rebuttal, EGU asserts that OCS's proposal to move to a 15-year baseline retains pre-2014 annual HDD that are much higher than recent experience, biasing the average upward.[104] EGU acknowledges that "generally a larger sample size will provide a better estimate, provided the sample is unbiased."[105] EGU references EGU Exhibit 6.04R to illustrate its claimed upward bias for pre-2014 HDD, but that exhibit also appears to show downward bias at least in 2012 (i.e., pre-2014), which is unexplained by EGU. EGU also testified that OCS's proposal is preferable to a 20-year baseline, and acknowledged that "higher HDD are expected in coming heating seasons[.]"[106]

We find the evidence supports that the HDD calculation should change from the current 20-year period. We do not find EGU's evidence adequately supports the extreme change in the HDD calculation that would result from using a 10-year baseline. Rather, we find OCS's proposal to change the HDD period to 15 years, will likely better account for actual temperatures than a 20-year period. We thus conclude

---

[102] *See id.* at 10:217-18.
[103] *See* Nov. 18, 2025 Hr'g Tr. at 243:15-16.
[104] *See* D. Landward Phase II Rebuttal Test. at 5:113-6:118.
[105] *See id.* at 3:54-56.
[106] *See id.* at 6:119-20.

that a change to the 15-year HDD calculation period, as proposed by the OCS, is in the public interest, and we approve that change.

3. NGV Subsidy

EGU requests approval of a subsidy to support the NGV class. The NGV class has not been subsidized since 2013. EGU acknowledges a steady decline of the NGV class since 2013, which has resulted in a drastic decline in revenues collected from the NGV class. EGU maintains, however, that a subsidy to support the NGV class for the Test Year is just and reasonable and in the public interest. In support of this request, EGU relies on Utah Code Ann. § 54-4-13.1 ("Section 13.1") and Utah Code Ann. § 54-4-13.4 ("Section 13.4").[107] To satisfy either Section 13.1 or Section 13.4, EGU must provide evidence allowing the PSC to make certain findings.

Section 13.4, titled "Natural gas fueling stations and facilities," provides:

> (1) The commission shall find that a gas corporation's expenditures for the construction, operation, and maintenance of natural gas fueling stations and appurtenant natural gas facilities are in the public interest and are just and reasonable, if:
>
> > (a) the gas corporation's expenditures for the fueling stations and appurtenant facilities:
> > (i) are prudently incurred; and
> > (ii) do not exceed $5,000,000 in any calendar year;
> >
> > (b) the gas corporation shows that the estimated annual incremental increase in revenue related to the stations and facilities

[107] EGU relied on Utah Code Ann. § 54-4-13.1 in the Application (*see* Application at 8) and in its written direct testimony (*see* A. Summers Direct Test. at 10:255-61) on this issue, but then ignored that code provision and instead relied solely on Utah Code Ann. § 54-4-13.4 in its written rebuttal testimony and its testimony at hearing.

> exceeds 50% of the annual revenue requirement of the stations and facilities; and
>
> (c) the stations and facilities are in service and are being used and useful.

EGU qualifies as a gas corporation under Section 13.4 and its request seeks the NGV subsidy to offset its expenditures for the operation and maintenance of its natural gas fueling stations. Thus, Section 13.4 requires the PSC to find that EGU's request is in the public interest and just and reasonable, but only if EGU meets each of the requirements set forth in subsections (a), (b), and (c) of Section 13.4.

EGU testified that it meets each of these requirements.[108] The only evidence regarding the requirement of subsection (b) is EGU's testimony that "[e]ven at reduced [sales] volumes, [EGU's NGV fueling] stations continue to meet the revenue objective of section (1)(b)[,]"[109] and that the stations "continue to meet the revenue objectives … with NGV station users currently generating 70 percent of the class revenue requirement."[110] However, this testimony fails to show "that the ***estimated annual incremental increase in revenue*** related to the stations and facilities exceeds 50% of the annual revenue requirement of the stations and facilities[.]"[111] That is, EGU provides no evidence that there has been any estimated annual increase in revenue,

---

[108] *See* Phase II Rebuttal Test. of J. Stephenson filed Oct. 16, 2025 at 2:28-3:59 (hereafter, "J. Stephenson Phase II Rebuttal Test.").
[109] *Id.* at 2:52-53.
[110] Nov. 18, 2025 Hr'g Tr. at 122:2-5.
[111] Utah Code Ann. § 54-4-13.4(1)(b) (emphasis added).

which is a requirement of the statute. DPU's testimony also supports this conclusion.[112]

Section 13.1, titled "Natural gas vehicle rate," provides:

> (1) The commission may find that a gas corporation's request for a natural gas vehicle rate that is less than full cost of service is:
>
> (a) in the public interest; and
> (b) just and reasonable.

EGU qualifies as a gas corporation under Section 13.1 and its request seeks a natural gas vehicle rate that is less than full cost of service. Thus, the PSC may allow the NGV subsidy only if it is in the public interest and just and reasonable.

EGU asserts that its requested NGV subsidy is in the public interest. EGU admits that its sales volumes of compressed natural gas ("CNG"), which is the fuel for NGVs, have been steadily decreasing since 2013, that vehicle manufacturers have moved away from NGVs and towards electric vehicles ("EVs"), and that some NGV users have built their own fueling facilities.[113] EGU also asserts that if the NGV subsidy is not approved, the price of CNG would be comparable to the cost of gasoline, which would be a substantial increase in the cost to users of CNG. EGU further asserts its NGV stations "still serve an important function in providing clean and reliable fuel[,]" and

---

[112] *See e.g.*, Nov. 18, 2025 Hr'g Tr. at 187:1-25.
[113] *See* A. Summers Direct Test. at 10:248-53.

even with the growth in EVs, "there remains an important role for natural gas in functions that are more costly and inefficient to electrify."[114]

DPU recommends EGU phase out its NGV program or increase NGV rates to eliminate the subsidy,[115] while OCS and ANGC oppose the NGV subsidy.[116] All of these parties concur with EGU's admission that its sales volumes of CNG have steadily decreased since 2013.

DPU testified that EGU's NGV program no longer serves the broader public interest in advancing an alternative fuel. DPU testified that if the NGV subsidy is approved, "all [EGU] customers (whether they drive a NGV or not) [will be] paying [approximately $900,000] for a program that benefits very few."[117] DPU also testified that since at least 2020, the number of NGV vehicles registered in Utah has been declining, while the number of non-NGVs (e.g., EVs, hybrid EVs ("HEVs"), and plug-in hybrid EVs ("PHEVs")) have grown at a significant rate.[118] DPU acknowledges that if the NGV subsidy is not approved, then the full cost of service for CNG users will be

---

[114] J. Stephenson Phase II Rebuttal Test. at 2:24-28.
[115] *See* Phase II Direct Test. of A. Orton filed Sept. 16, 2025 at 7:150-51 (hereafter, "A. Orton Phase II Direct Test."), A. Orton Phase II Surrebuttal Test. at 5:102-03, and Nov. 18, 2025 Hr'g Tr. at 181:12-15.
[116] UAE does not disagree with the positions of these parties. *See* Nov. 18, 2025 Hr'g Tr. at 271:24-272:1.
[117] *See* A. Orton Phase II Direct Test. at 2:48-51.
[118] *See e.g., id.* at 3:69-4:90. DPU testified that "[out] of the 3,076,200 vehicles registered in Utah in 2023, only 2,200 were CNG[,]" compared to "40,000 registered EVs, 83,200 HEVs, and 13,000 PHEVs." *Id.* at 4:87-89.

comparable to the price of gasoline.[119] DPU further testified that if the NGV subsidy is not approved, CNG users will still have access to fueling stations.[120]

OCS similarly testified that the NGV subsidy would cost all EGU customers approximately $900,000,[121] and that manufacturers have stopped building NGVs. ANGC testified that EGU has provided "no evidence that its Utah ratepayers can expect to derive benefits from the proposed [NGV] subsidy that equal or exceed the amount of the proposed subsidy."[122] ANGC also asserts that EGU's evidence confirms that there are alternative CNG providers.

We find EGU has failed to meet all of the requirements under Utah Code Ann. § 54-4-13.4, which it must do, and therefore conclude that this statute does not provide a basis upon which EGU is allowed to recover its proposed NGV subsidy. We also find that the decline in NGV volumes, limited customer participation, and falling CNG revenues, as well as the fact that customers are not investing in NGVs, opting instead for EVs or HEVs, does not support a finding that the requested NGV subsidy is in the public interest or just and reasonable. We further find that EGU has failed to show, as required under Utah Code Ann. § 54-4-13.1, that its requested NGV subsidy is

---

[119] *See* A. Orton Phase II Direct Test. at 2:41-45.
[120] *See id.* at 6:118-20.
[121] *See* J. Daniel Phase II Direct Test. at 11:244-49.
[122] Phase II Direct Test. of B. Oliver filed Sept. 16, 2025 at 33:705-07 (hereafter, "B. Oliver Phase II Direct Test.").

in the public interest and is just and reasonable. We therefore deny EGU's NGV subsidy request.[123]

4. Splitting GS Class

DPU initially proposed splitting the General Service (GS) class because, among other reasons, it contains too many diverse customers and results in an undesirable intra-class subsidy. DPU later acknowledged "[t]his is a complicated issue that requires more data and analysis to be adequately resolved[,]" especially since it impacts over 99 percent of EGU's customers.[124] DPU testified that in discussions with EGU, EGU stated it would be unable to implement a split of the GS class for purposes of this rate case and DPU "was unable to find a reason to question this assertion."[125] Consequently, DPU no longer proposes splitting the GS class at this time because it is impractical due to the time limitations in this proceeding and because "no clear alternative has been thoroughly studied."[126] DPU requests a separate docket be opened for purposes of further studying this issue.

OCS is not convinced that the GS class should be split because EGU has had a large GS class for many years. However, although OCS voiced potential concerns about the effort and expense involved in properly studying this issue, OCS does not

[123] We reiterate here that, based on the evidence, NGVs will still be able to access CNG from other sellers of CNG or from EGU at a non-subsidized rate.
[124] Phase II Direct Test. of M. Pernichele filed Sept. 16, 2025 at 2:31-34 (hereafter, "M. Pernichele Phase II Direct Test.").
[125] Nov. 18, 2025 Hr'g Tr. at 214:6-11. EGU confirmed its inability on this point. *See id.* at 100:20-102:17.
[126] *Id.* at 214:11-14.

oppose investigating this issue further. EGU also agreed that further study of this issue is appropriate.

Based on the evidence, we decline to split the GS class at this time. EGU, DPU, and OCS have testified they are open to studying whether it is reasonable to split the GS class, and if so, how, before the next GRC. We therefore find and conclude that a separate proceeding is an appropriate and reasonable means to evaluate the possibility of splitting the GS class. Accordingly, we will establish an investigatory proceeding in a new docket shortly after the reconsideration period for this order concludes. This will provide adequate time for study before EGU files its next GRC.

5. TSL Rate Design and Changes to Blocks

EGU proposes leaving the declining block structure for Transportation Service (TS) customers the same as what is currently in effect.[127] This would leave the volumetric rate blocks at the first 10,000 Dth, next 112,500 Dth, next 477,500 Dth, and over 600,000 Dth for TBF, MT, and TSL customers. For TSS and TSM customers, the blocks would remain at the first 200 Dth, next 1,800 Dth, and over 2,000 Dth.[128] EGU asserts this block structure has been authorized over the last several decades, has been generally unopposed through past GRC proceedings, and is a stable and predictable rate option.[129]

---

[127] *See* A. Summers Direct Test. at 21:548-52.
[128] *See id.*, EGU Exhibit 5.10 at Tab EGU_5.10p4_(TSS,TSM).
[129] *See* A. Summers Direct Test. at 20:531-38.

Nucor proposes a new block rate structure for the TSL class of the first 20,000 Dth, next 20,000 Dth, next 40,000 Dth, and over 80,000 Dth.[130] Nucor asserts this block structure segregates customers consistent with economies of scale attributable to gas delivery through larger diameter pipes. Nucor also asserts it makes no sense to include the fourth block as proposed by EGU, because that block has zero customers. Similarly, Nucor further asserts the general structure creates little separation in average rates across TSL customers as 78 percent of customers have volumes which do not exceed the second block.

Nucor also asserts that the small block discounts, combined with the high concentration of customers in the second block, restrict the rate design from effectively differentiating between low-volume, high-cost customers and high-volume, low-cost customers.[131] According to Nucor, because the incremental cost of large diameter mains is less than the incremental volume delivered by large diameter mains, high-volume customers are typically less costly to serve than low-volume customers within this rate group. As such, Nucor stated that the TSL rate block structure should be more even in its block customer count distribution and more clearly differentiate between low- and high-volume gas delivery costs.[132]

---

[130] *See* L. Kaufman Phase II Direct Test. at 16, Table 3.
[131] *See id.* at 19:384-93.
[132] *See id.* at 20:395-98.

Regarding volumetric rates, Nucor specifically proposes a flat declining block rate of 30 percent per block. Nucor argues this proposed rate design would more accurately reflect the cost savings provided by the economies of scale as pipe diameters increase compared to the current rate spread.[133]

UAE does not support Nucor's recommendation. UAE asserts Nucor's proposed rate design would disproportionately burden smaller TSL customers by significantly shifting the rate distribution towards the lower-volume customers. According to UAE, Nucor bases its recommendation on the declining per Dth cost of transporting gas through larger diameter pipes, but this declining unit cost is not reflected in the allocation of feeder line costs in any of the cost-of-service studies proposed in this case. In the absence of a cost-of-service study that makes TSL class specific feeder-line allocations, UAE asserts that Nucor's proposed block structure would be inequitable to smaller TSL customers.[134]

ANGC supports Nucor's proposal regarding the flat 30 percent declining volumetric rate adjustment, citing it as a "significant improvement" over EGU's proposal. ANGC agrees that EGU's rate design does not appropriately account for the economies of scale found as pipe diameters increase. ANGC notes that EGU's volumetric rate proposals vary widely between blocks. For example, the volumetric

---

[133] *See id.* at 25, Table 9. The full rate design is provided in Nucor Exhibit 1.4.

[134] *See* C. Higgins Phase II Rebuttal Test. at 13:207-21.

rate of Block 3 for TSS customers is proposed to increase by 241.1 percent, while Block 1 is only proposed to increase by 39.6 percent.[135]

We decline to approve the proposed changes to the currently effective TS class rate block structure and volumetric rate design. We are persuaded by UAE's argument that Nucor's proposed rate design would disproportionately burden smaller TS customers by significantly shifting the rate distribution towards lower-volume customers. As has been our long-standing policy, we continue to strive for eventual movement toward full cost of service rates, including for all the TS classes and subclasses. We further find that the current block structure has only been in effect since the 2022 GRC. We conclude that more time and experience is needed to assess the data addressing the current blocks that comprise the TS classes. As such, we conclude that the TS blocks shall continue as ordered in the 2022 GRC.

6. Low-Pressure Surcharge for TSL customers

Nucor proposes a "Low[-]Pressure Surcharge" as a new charge to be applied to customers with service lines receiving gas through an intermediate high pressure ("IHP") main. Nucor proposes a charge of $7,407 per meter, per month to recover the calculated $888,850 in IHP main related costs across the 10 (out of 47) TSL meters that would qualify.[136] According to Nucor, these revenues should be offset by a

---

[135] *See* Phase II Rebuttal Test. of B. Oliver filed Oct. 16, 2025 at 5:98-105. This discrepancy is recognized and resolved by EGU in Exhibit 5.16SR.

[136] *See* L. Kaufman Phase II Direct Test. at 15:326-16:329. For a complete explanation of how Nucor arrived at these numbers, *see id.* at 17:342-18:376.

reduction in the volumetric rates. Nucor asserts that EGU does not dispute Nucor's evidence that there is a subclass of customers that use low pressure mains and drive allocation of these costs to the TSL class.[137] Nucor also asserts EGU has supported "splitting" classes in the past, citing the creation of the TSS, TSM, and TSL classes in the 2022 GRC as an example. Nucor further asserts EGU has sufficient time to implement this surcharge in this rate case, highlighting that the charge would only apply to 10 very large customers which, according to Nucor, should not be difficult to implement.[138]

EGU opposes the surcharge, asserting it violates the principle of average ratemaking, which has been a long-standing foundation of its rate design. According to EGU, average ratemaking allocates costs across customer classes, not individual customers or subsets of customer classes.[139] EGU also asserts that implementing a Low-Pressure Surcharge would effectively create a subclass within TSL, which undermines the integrity of a class-based system.[140] EGU further asserts that adopting the Low-Pressure Surcharge would set a precedent for disaggregating costs within rate classes.[141] At hearing, EGU testified that if the PSC approves this surcharge, it likely could not implement it for purposes of this rate case on such short notice.[142]

[137] *See* Phase II Surrebuttal Test. of L. Kaufman filed Nov. 4, 2025 at 7:136-40.
[138] *See* Nov. 19, 2025 Hr'g Tr. at 316:11-22.
[139] *See* A. Summers Phase II Rebuttal Test. at 15:297-302.
[140] *See id.* at 15:309-14.
[141] *See id.* at 15:321-22.
[142] *See* Nov. 18, 2025 Hr'g Tr. at 96:22-97:13 & 97:21-23.

DPU supports Nucor's proposal for a monthly per meter charge of $7,407. DPU asserts that, when possible, large discrepancies between the costs caused by different customers should be remedied. TSL customers who do not use the IHP system should not pay for costs associated with the IHP system, as this results in an intra-class subsidy and strays from cost-causation principles.[143] According to DPU, EGU already solves a similar problem in a manner similar to the proposed Low-Pressure Surcharge with its Basic Service Fee ("BSF") charges. These BSF charges correspond to one of four expense categories for different meter types and are meant to accurately reflect costs caused by different types of customers within the same customer class.[144]

We approve the creation of the proposed Low-Pressure Surcharge.[145] We find that the evidence supports the proposed surcharge to be a cost-effective and non-complex means of more appropriately allocating costs caused by a small group of distinct customers within the larger TSL class. We find it persuasive that, similar to EGU's existing differentiated BSF charges, the Low-Pressure Surcharge will efficiently allocate costs across heterogeneous customers within the same customer class. We also reject the assertion that adopting this surcharge will set a dangerous precedent for disaggregating costs within rate classes. We disavow any intent to create such a

---

[143] *See* Phase II Surrebuttal Test. of M. Pernichele filed Nov. 4, 2025 at 2:31-33.
[144] *See id.* at 2:33-38.
[145] The Low-Pressure Surcharge we approve is lower than requested, as shown in Table 4.

precedent. Finally, because the surcharge will only apply to ten customers, we find EGU should be able to implement this surcharge in this rate case, in light of the static nature of this charge. Based on these findings, we conclude that EGU's implementation of the proposed Low-Pressure Surcharge is in the public interest and is just and reasonable.

7. Administrative Charge

EGU proposes a 25 percent increase in the Administrative Charge applied to TBF, TSS, TSM, TSL, and MT customers. This would increase the Administrative Charge from $200/month to $250/month, or from $2,400/year to $3,000/year. EGU presents two drivers for the change. First, EGU no longer shares its gas control function and software platform[146] with Mountain West Pipeline, causing EGU's labor and software costs to increase. Second, EGU states it has experienced an increase in headcount for the Key Accounts department.[147] EGU calculated the proposed increase by identifying all the costs incurred through administering the transportation rates for all transportation classes and dividing that cost among the transportation customers.

ANGC is the only party to oppose the proposed Administrative Charge increase. ANGC criticizes EGU's classification of costs for the Administrative Charge in this docket as compared to the 2022 GRC. There, for example, commercial support and nominations/scheduling were separately identified and tracked cost components, but

---

[146] See Nov. 18, 2025 Hr'g Tr. at 83:14-84:25, citing EGU Exhibit 5.09, line 17.
[147] *See* A. Summers Phase II Rebuttal Test. at 20:429-30.

in this docket ANGC asserts these same costs have seemingly been consolidated into gas supply and gas control costs.[148] Thus, according to ANGC, without explicit ties of these costs by FERC account, there is little ability to verify the reasonableness of these cost recategorizations.[149]

We find EGU's explanation of its increased costs to be credible and supported by facts presented in this docket. We approve the proposed Administrative Charge increase of 25 percent, or $50/monthly.

To better understand how telemetry equipment and EGU's maintenance thereof impacts the Administrative Charge, we also direct EGU to conduct a study and present a report to the PSC on: (1) how EGU's telemetry equipment is maintained, both scheduled and unscheduled; (2) how EGU tracks and maintains running records of telemetry maintenance site visits, and all associated costs of those visits; (3) whether EGU customers using telemetry have any obligation to maintain that equipment, and if so, what standards EGU expects those customers to follow in such maintenance; and (4) a clear articulation of what EGU specifically does to maintain telemetry equipment if a customer leaves the TS class. This study should also include the impact on the frequency and nature of maintenance resulting from customer flow levels, delivery pressures, and gas quality requirements as identified by ANGC.[150] We direct EGU to file

---

[148] At hearing, counsel for ANGC questioned EGU's witness extensively on issues relating to telemetry. *See e.g.*, Nov. 18, 2025 Hr'g Tr. at 58:21-63:3. While not persuasive for purposes of our ruling on this issue, this line of questioning raised some questions in our minds, which are addressed below.
[149] *See* B. Oliver Phase II Direct Test. at 44:939-45:974.
[150] *See id.* at 57:1217-20.

this report by the end of 2026 or to notify the PSC within 30 days of this order why that due date is impractical and to propose an alternative schedule. Our intent is that the report will assist in further evaluating recovery of this category of costs in EGU's next rate case.

8. TBF Class

a. Discount

The PSC approved the reduction of the TBF discount from 50 percent to 40 percent in the 2022 GRC to provide the appropriate incentives for the TBF class.[151] DPU asserts that EGU's Application appears to continue the TBF discount at 50 percent instead of the PSC-authorized 40 percent. UAE disagrees and testified DPU's assertion is unfounded because the 40 percent discount is calculated and shown in EGU's evidence, specifically in the "COS Input" tab of EGU's model.[152] EGU's testimony at hearing confirmed this point.[153] DPU did not dispute EGU's or UAE's testimony.

DPU also asserts that the TBF class has a negative rate of return index, indicating EGU loses money serving these customers. According to DPU, the GS Class currently overpays by $13,658,106, which largely subsidizes the TBF Class, which in turn underpays by $9,472,733.[154] OCS expresses a similar concern.[155] DPU further

[151] *See* 2022 GRC Order at 51.
[152] *See* C. Higgins Phase II Rebuttal Test. at 10:158-60 (*citing* EGU Exhibit 5.14U – Electronic Model – Summers 5-14-2025, "COS Input" tab, Excel rows 47-51).
[153] *See* Nov. 18, 2025 Hr'g Tr. at 98:9-99:6.
[154] *See* M. Pernichele Phase II Direct Test. at 7:154-57.
[155] *See* Phase II Rebuttal Test. of J. Daniel filed Oct. 16, 2025 at 14:306-09.

states, however, that it understands that the rate of return index contains subjective elements and that there are significant sunk costs that would be difficult to recover should EGU lose TBF customers.[156]

EGU acknowledges that "the TBF class continue[s] to pay less than full cost, as it has for decades," asserting that allowing this practice helps "prevent these customers from bypassing the [EGU] distribution system."[157] UAE disagrees with DPU's assertion that EGU loses money serving the TBF class. UAE testified that a negative rate of return index is an expected outcome of an intentional, load-retention discount and does not indicate losses at the margin. According to UAE, the negative rate of return is calculated before the proposed rate increase, and TBF produces a positive return after applying EGU's proposed rate increase.[158] UAE also notes that TBF customers contribute to fixed cost recovery, benefiting non-TBF classes.

We find and conclude that the evidence supports that EGU's Application incorporates the PSC-authorized TBF rate discount of 40 percent, not 50 percent. We also find that the TBF discount exists to help prevent EGU losing TBF customers and that significant sunk costs exist that would be difficult to recover if EGU lost TBF customers. We therefore conclude that the established 40 percent TBF discount constitutes an appropriate and justifiable incentive for the TBF rate class.

---

[156] *See* M. Pernichele Phase II Direct Test. at 8:171-73..
[157] A. Summers Direct Test. at 11:284-87.
[158] *See* C. Higgins Phase II Rebuttal Test. at 11:179-81.

b. TBF Load Adjustment for Projected Growth

EGU's Application includes the TBF class among the transportation classes that pay a Basic Service Fee, an Administrative Charge, and a Firm Demand Charge, with the remainder of the revenue collected through volumetric rates.

UAE asserts that EGU's proposed cost allocation for the TBF class is inconsistent with the billing determinants used to design TBF rates, which materially inflates the proposed TBF rate increase.[159] According to UAE, this is caused by significant projected TBF load growth starting in June 2026, which is expected to increase firm demand by 85 percent and volumes by approximately 128 percent, as compared to prior levels. EGU bases the TBF class's Design Day contribution on the highest projected firm demand (post-load growth level) for a full year of demand costs, but for rate design, EGU combines five months of pre-growth data (January – May) with seven months of post-growth billing determinants (June – December).[160] UAE asserts "[t]his mismatch spreads the higher allocated demand costs over too few billing determinants, resulting in an overstated TBF rate increase."[161]

UAE recommends aligning the TBF billing determinants and cost allocation inputs. This involves adjusting the TBF volumes and firm demand billing determinants to apply the higher projected load to each month of the year and adjusting the TBF

---

[159] *See* C. Higgins Phase II Direct Test. at 8:117-21. *See also id.* at 14:230-33 (noting EGU's as-filed proposal would increase TBF rates by 44.7 percent, and the revised model results in a 45.1 percent increase, which is the highest increase proposed for any transportation class).
[160] *See id.* at 9:126-31.
[161] *Id.* at 9:131-32.

throughput for cost allocation to reflect the expected post-load growth level.[162] UAE states its adjustment increases TBF adjusted revenues at current rates by about $1.8 million, which would reduce the overall revenue deficiency associated with the Phase I Stipulation from $62 million to $60.2 million.[163]

EGU acknowledges UAE's arguments are logical,[164] but disagrees with UAE's recommended adjustment because the load increase is not expected until June 2026 and modifying billing determinants for the January – May 2026 period would not accurately reflect expected TBF usage. EGU also contends the adjustment would have a negative effect on the overall revenue requirement established in the Phase I Stipulation.[165] Furthermore, EGU challenged UAE for exceeding the scope of the Test Year by assuming the load will continue through 2027 and 2028, which falls outside of the Test Year. At hearing, UAE disputed EGU's assertion on this point, reaffirming its earlier position that its proposal is narrowly tailored to fix an internal inconsistency within the Test Year itself.

EGU proposes two alternatives to UAE's proposal, including a "gradualism adjustment" to limit the TBF class revenue increase to 1.5 times the system average (16.77 percent TBF class increase, based on the Phase I Stipulation revenue requirement),[166] and a step rate increase, where one rate is used for the first five

---

[162] *See id.* at 9:133-39.
[163] *See* C. Higgins Phase II Rebuttal Test. at 19:319-28.
[164] *See* A. Summers Phase II Rebuttal Test. at 10:165-67.
[165] *See id.* at 10:171-74.
[166] *See id.* at 10:186-91.

months and a higher rate is used for the remaining seven months.[167] While UAE does not reject EGU's potential alternatives, it asserts they possess inherent disadvantages, such as administrative inconvenience, a lack of full development, and implications beyond the TBF classes, UAE maintains its advocacy of a higher, post-load growth projection (June-December 2026 level) for all twelve months of the Test Year.[168]

We find UAE's proposal to align TBF billing determinants and cost allocation inputs will more reasonably and properly reflect the TBF class's projected cost responsibility during the Test Year. We also find that UAE's proposal does not consider, and therefore does not reflect, data from outside the Test Year. Instead, we are persuaded that UAE's recommendation is narrowly tailored to fix an internal inconsistency within the Test Year itself. We find EGU's alternative to limit the increase to the TBF class to no more than 1.5 times the system average would unnecessarily shift costs to other classes. And we find EGU's suggestion to implement a step rate increase to be overly complicated because it will impact the timing and implementation of rate increases for all classes. Based on these findings, we conclude that approval of the TBF load adjustment proposed by UAE is appropriate. This reduces the overall revenue deficiency associated with the Phase I Stipulation from $62 million to $60.2 million.

---

[167] *See* Nov. 18, 2025 Hr'g Tr. at 38:18-39:8.

[168] *See* Phase II Surrebuttal Test. of C. Higginsfiled Nov. 4, 2025 at 14:251-53 and Nov. 18, 2025 Hr'g Tr. at 269:17-19.

c. Temporarily Close TBF class

OCS raises concerns about new large load customers, including planned new large data centers, potentially seeking service on the discounted TBF rate schedule, claiming they have other bypass options. OCS asserts that if all these large new loads were allowed onto the discounted TBF rate, it could potentially burden existing residential and small commercial ratepayers.[169] OCS recommends that the PSC temporarily close the TBF rate class to new customers, pending additional study on the appropriateness of allowing new large customers in this rate class.

EGU agrees with OCS that the TBF class is evolving quickly, needs further analysis before the next general rate case, and should be temporarily closed to new customers.[170]

Based on the shared assessment of OCS and EGU regarding the rapid evolution of the TBF rate class and their agreement that a moratorium on new TBF customers is appropriate, we find the temporary closure of the TBF rate class to all new customers is justified. Accordingly, we will close the TBF rate class pending completion of a comprehensive study on this issue. We direct EGU, in consultation with DPU, OCS, and any other interested party, to begin work on this study and complete it by no later than the end of 2026. We also remind EGU that Section 5.02 of its Tariff requires EGU to seek PSC approval of any additional customers to the TBF class. Our examination of

[169] *See* J. Daniel Phase II Direct Test. at 25:533-36.
[170] *See* A. Summers Phase II Rebuttal Test. at 10:178-81.

information presented in this case suggests EGU may have added customers to the TBF class without the required PSC approval. We direct EGU to file with the PSC, within 30 days of the date of this order, a list of all TBF customers with a description of how and when PSC approval was obtained.

9. Basic Service Fee Charges

EGU recommends no changes to its current BSF charges. The BSF charges were established as the result of a settlement in EGU's 2013 general rate case and have been consistently applied in subsequent rate cases. EGU recalculates[171] the BSF charges during each rate case filing. EGU's recalculation of the BSF charges in this docket shows higher BSF charges may be warranted. EGU has determined, however, that existing BSF charges should remain at a level sufficient to collect the minimum required amount to serve an average customer in its respective BSF category. EGU acknowledges that any under-recovery of BSF costs through the BSF charges will be recovered through volumetric charges. EGU also testified that an increase to the BSF charges may adversely impact customers who are constrained by low or fixed incomes,[172] or be at odds with objectives of trying to encourage conservation.[173]

OCS supports EGU's proposal to make no changes to the BSF charges, testifying that EGU adequately supports its proposal.

---

[171] *See* A. Summers Direct Test., EGU Exhibit 5.08 at page 1 (summary of EGU's BSF calculations).
[172] *See* A. Summers Phase II Rebuttal Test. at 18:375-78.
[173] *See* Nov. 18, 2025 Hr'g Tr. at 95:24-96:3.

ANGC criticizes EGU's decision to maintain the BSF charges for all meter categories. ANGC asserts that EGU Exhibit 5.08 demonstrates the proposed BSF charges in this case under-recover the BSF costs and thus fail to adhere to principles of cost causation. ANGC further asserts that EGU's proposal to maintain the BSF charges at its current levels fails to appreciate potential intra-class rate subsidy impacts based on shifting cost recovery between BSF charges and volumetric charges. ANGC requests the PSC require EGU to "clearly demonstrate … (a) There is no duplication of cost recovery between the costs included in its BSF costs analysis and the costs [EGU] seeks to recover through its Administrative Charge for Transportation Service customers; and (b) EGU's classifications and allocations of costs within its Class Cost of Service Study appropriately portray cost-causative relationships."[174] ANGC does not, however, propose any alternative BSF charges.

We find that the evidence supports EGU's position that its proposed BSF charges are sufficient to recover the minimum costs required to serve an average customer. We further find policy considerations, such as the adverse impact an increase in the BSF charges may have on customers constrained by low or fixed incomes, or on conservation efforts, support EGU's position. Based on these findings, we conclude EGU's position is just and reasonable in result and in the public interest. We decline ANGC's request to require more of EGU on this issue and, in the absence of

---

[174] B. Oliver Phase II Direct Test. at 38:821-39:830.

any proposed alternatives, we conclude that no change to the BSF charges or calculations is warranted at this time.

10. Transportation Imbalance Charge (TIC)

DPU requests the PSC establish "a working group to review the behavior of the TS class customers."[175] The TIC rate was implemented to charge transportation customers for SNG services when used. EGU implemented the TIC, in part, to improve the daily accuracy of gas nominations, where only customer nominations outside of a set tolerance limit are assessed the TIC.

According to DPU, the TIC has provided an effective method for EGU to receive more accurate nominations from transportation customers over most of the history of the program. And although the TIC seemed to correct inaccurate nominations by TS customers, DPU asserts the efficacy of the penalty has recently waned and is seemingly disconnected from TS customer behavior. According to DPU, its quantitative TIC data analysis[176] shows that the TIC is not functioning as originally intended.

EGU asserts a working group to study the TIC is unnecessary. EGU states it has no operational concerns arising from daily transportation imbalances at the current levels, reminding the PSC it approved the TIC in a fully litigated and contested docket

[175] R. Daigle Phase II Direct Test. at 11:206-07.
[176] *See id.* at 11:199-200 (chart showing how Dth usage outside the tolerance limit has increased while the TIC penalty has decreased).

that included significant disagreement among the parties regarding its methodology and calculation.[177] EGU further asserts that EGU now has tariff provisions in place to address more pointed concerns about imbalances, such as a hold-burn to scheduled quantity and outright restrictions in usage. According to EGU, the higher imbalances observed in recent years by DPU are not at a level to cause concern or to adversely impact EGU's ability to operate its system.

While we appreciate DPU's analysis and concern about nominations outside the tolerance threshold trending upward in a declining penalty environment, EGU is the party that risks the most by erring on its TIC. We find EGU's testimony persuasive that the behavior observed by DPU does not rise to a level that warrants ordering a working group to review the TIC and therefore decline to do so.

11. General Rate Implementation

The rates and charges reflecting the decisions in this order are presented in Tables 3 and 4, below.

[177] *See* K. Mendenhall Phase II Rebuttal Test. at 4:91-5:95.

TABLE 3: MONTHLY FIXED CHARGES

Description	Current Charges	Approved January 1, 2026 Charges	$ Change	% Change
Basic Service Fees:				
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	**$200.00**	**$250.00**	**$50.00**	**25.0%**
Secondary	**$100.00**	**$125.00**	**$25.00**	**25.0%**

TABLE 4: BASE DNG RATES ($/Dth)

		Current Rates	Proposed Rates (Eff. 1/2026)	$ Change
GS, General Service				
Winter				
1st block	0 – 45	$3.42633	$3.92786	$0.50153
2nd block	over 45	$2.09098	$2.59251	$0.50153
Summer				
1st block	0 – 45	$2.79606	$3.21808	$0.42202
2nd block	over 45	$1.46071	$1.88273	$0.42202
FS, Firm Sales				
Winter				
1st block	0 – 200	$2.14519	$2.40476	$0.25957
2nd block	201 – 2,000	$1.59984	$1.85941	$0.25957
3rd block	over 2,000	$1.02577	$1.28534	$0.25957
Summer				
1st block	0 – 200	$1.64533	$1.66734	$0.02201
2nd block	201 – 2,000	$1.09998	$1.12199	$0.02201
3rd block	over 2,000	$0.52591	$0.54792	$0.02201
NGV, Natural Gas Vehicles		$10.98248	$15.83569	$4.85321

IS, Interruptible Sales				
1st block	0 – 2,000	$0.89296	$1.39400	$0.50104
2nd block	2,001 – 20,000	$0.10582	$0.60686	$0.50104
3rd block	over 20,000	$0.04823	$0.54927	$0.50104
TSS, Transportation Sales, Small				
1st block	0 – 200	$1.20107	$1.73937	$0.53830
2nd block	201– 2,000	$0.71194	$1.03102	$0.31908
3rd block	over 2,000	$0.19707	$0.28539	$0.08832
Demand Charge, monthly	Per Dth	$3.36579	$4.08000	$0.71421
TSM, Transportation Sales, Medium				
1st block	0 – 2,000	$1.18345	$1.48337	$0.29992
2nd block	over 2,000	$0.61168	$0.76670	$0.15502
Demand Charge, monthly	Per Dth	$3.36579	$4.08000	$0.71421
TSL, Transportation Sales, Large				
1st block	0 – 10,000	$0.68034	$0.78876	$0.10842
2nd block	10,001 – 122,500	$0.64600	$0.74895	$0.10295
3rd block	122,501 – 600,000	$0.49318	$0.57177	$0.07859
4th block	over 600,000	$0.21061	$0.24417	$0.03356
Low-Pressure Surcharge, monthly†	Per customer	N/A	$6,756.50	$6,756.50
Demand Charge, monthly	Per Dth	$3.36579	$4.08000	$0.71421
† Applicable only to those TSL customers taking service from small or large diameter mains, referenced in Nucor Exhibit 1.5, EGU Response to Nucor Data Request 2.17.				
TBF, Transportation Bypass Firm				
1st block	0 – 10,000	$0.55936	$0.76476	$0.20540
2nd block	10,001 – 122,500	$0.53110	$0.72616	$0.19506
3rd block	122,501 – 600,000	$0.40547	$0.55438	$0.14891
4th block	over 600,000	$0.17316	$0.23674	$0.06358
Demand Charge, monthly	Per Dth	$2.10886	$2.45000	$0.34114

MT, Municipal Transportation				
All usage	Per Dth	$0.90379	$1.00314	$0.09935

C. Tariff Issues

EGU proposes numerous changes to its Tariff, including substantive, conforming, and housekeeping changes. Most of EGU's proposed Tariff-related issues have been resolved, but an issue regarding Tariff Section 9.02 remains for the PSC's determination. Specifically, EGU proposes to add language in this section that will include a $50 million system improvement threshold for requiring a customer to make an upfront payment for preliminary engineering costs for large-scale projects.

DPU recommends approval of this threshold amount.[178] OCS opposes the proposed $50 million threshold, recommending $10 million instead.[179]

In response to OCS's recommendation, EGU testified that lowering the threshold to $10 million would significantly expand the number of projects subject to this requirement — many of them routine projects — including those with minimal and not overly burdensome upfront engineering effort.[180] According to EGU, this could increase EGU's administrative overhead and would lengthen the overall project siting process for potential customers.

---

[178] *See* Phase II Surrebuttal Test. of E. Orton filed Nov. 4, 2025 at 4:84-87.
[179] *See* J. Daniel Phase II Direct Test. at 26:567-70.
[180] *See* Phase II Rebuttal Test. of J. Parks filed Oct. 16, 2025 at 4:75-80.

OCS's written rebuttal and surrebuttal testimony did not address EGU's response to OCS's proposal to lower the threshold. Addressing EGU's response to OCS's $10 million dollar threshold for the first time at hearing, OCS acknowledged EGU's points were reasonable,[181] but then testified "maybe [$]20 million might be the right number[,]"[182] and offered no analysis to substantiate that possible threshold, or why EGU's proposed $50 million threshold was excessive.

We find the evidence supports EGU's requested addition of a $50 million system improvement threshold in Section 9.02 of the Tariff. We further find that there is insufficient evidence to support OCS's proposed alternative threshold of $10 million, and the evidence shows that lowering this threshold to $10 million would likely result in adverse outcomes. We therefore conclude that EGU's request is in the public interest, and we approve it.

We are satisfied that the record demonstrates that the remainder of EGU's proposed Tariff modifications (with one exception we describe below) are either unopposed or are no longer contested. The record includes the testimony of EGU and DPU at hearing that EGU, not EGU customers, will bear the financial burden resulting from the proposed revisions to Section 10.2 of the Tariff.[183] Accordingly, we find all other Tariff changes EGU proposes, as amended and reflected in the parties' "Matrix of

[181] *See* Nov. 18, 2025 Hr'g Tr. at 263:10-18.
[182] *Id.* at 263:24.
[183] *See id.* at 164:4-18 (EGU testimony) and *id*. at 176:7-25 (DPU testimony).

Agreed or Partially Agreed Issues,"[184] the Phase II rebuttal, surrebuttal, and evidentiary hearing testimony of Jordan Parks, and as reflected in DPU's Phase II direct, surrebuttal, and evidentiary hearing testimony of Eric Orton, are in the public interest and just and reasonable in result. We therefore approve them.

EGU's proposed Tariff, Sections 2.07 and 9.02, titled "Current Commission-Allowed Pre-Tax Rate of Return," shows a change to this value (to 9.43 percent), but the Phase I Stipulation, and our Order, only approves the use of the current value (8.46 percent). We therefore decline to approve the 9.43 percent shown in EGU's proposed Tariff, Sections 2.07 and 9.02.

VII. ORDER

Pursuant to our discussion, findings, and conclusions:

1. We approve the Phase I Stipulation.
2. We approve a revenue requirement increase of $60,185,374, as allocated to the various customer classes as shown in Table 1 and Table 4.
3. We approve the continuation of the Conservation Enabling Tariff ("CET"), subject to the conditions and direction set forth herein, and approve the CET revenue as shown in Table 2.

[184] *See* Phase II Matrix of Agreed or Partially Agreed Issues (filed Nov. 26, 2025). EGU, for itself and on behalf of the parties, filed at the direction of the PSC a cover email and summary of the agreed-upon items relating to Phase II of this docket. According to the cover email, this matrix "only includes issues where one or more parties agree and the remaining parties did not take a position."

4. We approve EGU's monthly fixed charges as shown in Table 3.
5. The new rates shall be effective January 1, 2026.
6. We deny EGU's request to calculate Normal Heating Degree Days using a 10-year timeframe, but we instead approve use of a 15-year timeframe.
7. We deny EGU's request for a subsidy to support the NGV class.
8. We approve a new low-pressure surcharge to be applied to EGU customers as described herein.
9. We direct EGU to conduct a study and present a report to the PSC concerning telemetry equipment, as requested herein. We direct EGU to file this report by the end of 2026, or to notify the PSC within 30 days of this order why that due date is impractical and to propose an alternative schedule.
10. We direct EGU to file within 30 days from the date of this order a list of all TBF customers, including a description of how and when PSC approval for these customers was obtained.
11. We approve UAE's request to align the cost allocation for the TBF class with the billing determinants used to design TBF rates as described herein, which results in a reduction to the overall

revenue deficiency associated with the Phase I Stipulation from approximately $62 million to approximately $60.2 million.

12. We temporarily close the TBF class to any new customers and direct EGU, in consultation with DPU, OCS, and any other interested party, to begin work on a study relating to the issues discussed in the testimony on this topic and complete it by no later than the end of 2026.

13. We will establish an investigatory proceeding in a new docket concerning the possibility of splitting the GS class.

14. We deny DPU's request for the formation of a working group relating to the Transportation Imbalance Charge.

15. We approve only those Tariff-related issues as set forth herein.

DATED at Salt Lake City, Utah, December 24, 2025.

/s/ Jerry D. Fenn, Chair

/s/ David R. Clark, Commissioner

/s/ John S. Harvey, Ph.D., Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#343168

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 24, 2025, a true and correct copy of the foregoing was delivered upon the following as indicated below:

By Email:

Jenniffer Nelson Clark (jenniffer.clark@enbridge.com) and
(jenniffer.clark@dominionenergy.com)
Ronit Barrett (barrett@whitt-sturtevant.com)
Christopher W. Flynn (flynn@whitt-sturtevant.com)
Anne W. Mitchell (mitchell@whitt-sturtevant.com)
Albert D. Sturtevant (sturtevant@whitt-sturtevant.com)
Attorneys for Enbridge Gas Utah

Austin Summers (austin.summers@enbridge.com) and
(austin.summers@dominionenergy.com)
Enbridge Gas Utah

Phillip J. Russell (prussell@jdrslaw.com)
JAMES DODGE RUSSELL & STEPHENS, P.C.
Kevin Higgins (khiggins@energystrat.com)
Neal Townsend (ntownsend@energystrat.com)
Justin Bieber (jbieber@energystrat.com)
Keirsten Ignjatovic (keirsten@energystrat.com)
Energy Strategies, LLC
Utah Association of Energy Users

Damon E. Xenopoulos (dex@smxblaw.com)
Laura W. Baker (lwb@smxblaw.com)
Stone Mattheis Xenopoulos & Brew, PC
Jeremy R. Cook (jcook@ck.law)
Cohne Kinghorn
Nucor Steel-Utah, a Division of Nucor Corporation

Mark A. Davidson (mdavidson@fwlaw.com)
Fairfield and Woods, P.C.
Curtis Chisholm (cchisholm@ie-cos.com)
Integrated Energy Companies
Bruce Oliver (revilohill@verizon.net)
Revilo Hill Associates, Inc.
American Natural Gas Council

TSgt James B. Ely (james.ely@us.af.mil)
Mr. Thomas A. Jernigan (thomas.jernigan.3@us.af.mil)
Maj Leslie R. Newton (leslie.newton.1@us.af.mil)
Ebony M. Payton (ebony.payton.ctr@us.af.mil)
Capt Matthew R. Vondrasek (matthew.vondrasek.1@us.af.mil)
AF/JAOE-ULFSC (ULFSC.Tyndall@us.af.mil)
Federal Executive Agencies

Patricia Schmid (pschmid@agutah.gov)
Patrick Grecu (pgrecu@agutah.gov)
Robert Moore (rmoore@agutah.gov)
Assistant Utah Attorneys General

Madison Galt (mgalt@utah.gov)
Division of Public Utilities

Alyson Anderson (akanderson@utah.gov)
Cameron Irmas (cirmas@utah.gov)
Asami Kobayashi (akobayashi@utah.gov)
Jennifer Ntiamoah (jntiamoah@utah.gov)
Bela Vastag (bvastag@utah.gov)
Alex Ware (aware@utah.gov)
(ocs@utah.gov)
Office of Consumer Services

/s/ Melissa R. Paschal
Lead Paralegal