Decision No. C25-0840

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 25A-0044EG

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE MOUNTAIN ENERGY PROJECT AND ASSOCIATED CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR SUPPLEMENTAL SUPPLY.

COMMISSION DECISION APPROVING SETTLEMENT AGREEMENT WITH MODIFICATIONS, GRANTING APPLICATION AS MODIFIED AND GRANTING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

Issued Date: November 26, 2025
Adopted Date: November 19, 2025

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I. BY THE COMMISSION

A. Statement

1. On January 16, 2025, Public Service Company of Colorado ("Public Service" or "Company") filed an Application requesting that the Commission approve and authorize the Company to pursue the Mountain Energy Project ("MEP" or "Project") and that the Commission grant an associated Certificate of Public Convenience and Necessity ("CPCN") for certain facilities providing supplemental supply in its Eastern Mountain Gas System ("EMGS").

2. By this Decision, we approve the Settlement Agreement joined by all parties save for the Office of the Utility Consumer Advocate ("UCA") with the clarifications set forth in this Decision as well as certain modifications.

B. Procedural History

3. On January 16, 2025, Public Service filed the Application. Public Service filed Direct Testimony of five witnesses in support of the Application.

4. On March 11, 2025, through Decision No. C25-0173, the Commission referred the Application to Megan M. Gilman to act as Hearing Commissioner and to render an initial commission decision pursuant to § 40-6-109(6), C.R.S. In the same Decision, the Commission presented a cost recovery proposal for the Company and intervening parties to address in testimony. The proposal would levy a fee on new customers in the EMGS.

5. By Decision R25-0197-I, issued on March 19, 2025, Hearing Commissioner Gilman established the parties in this proceeding: Public Service, Trial Staff of the Colorado Public Utilities Commission ("Staff"), the Colorado Office of the Utility Consumer Advocate ("UCA"), the Colorado Energy Office ("CEO"), Southwest Energy Efficiency Project ("SWEEP"), the Mountain Community Coalition ("MCC"), Colorado Energy Consumers Group ("CEC"), and Sierra Club.

6. Hearing Commissioner Gilman issued Decision No. R25-0266-I on April 10, 2025, granting the Company's Motion for Extraordinary Protection.

7. By Decision No. R25-0297-I, issued April 16, 2025, Hearing Commissioner Gilman established the procedural schedule, scheduled a remote evidentiary hearing, extended the Decision deadline Pursuant to § 40-6-109.5, C.R.S., and set procedures for the evidentiary hearing.

8. On May 6, 2025, the Company provided Supplemental Direct Testimony on supplemental supply, design day assumptions, other capacity constraints, NPA areas, the feasibility survey conducted by PA Consulting, electrical upgrades inherent in the Project, and modified cost-benefit analysis ("CBA") runs, as required by Decision No. R25-0217-I.

9. On June 5, 2025, the following intervening parties filed Answer Testimony: Staff, UCA, CEO, MCC, Sierra Club, and SWEEP.

10. Hearing Commissioner Gilman held a public comment hearing in Frisco, CO on June 25, 2025, as well as a virtual public comment hearing August 4, 2025, pursuant to Decision No. R25-0405-I.

11. On July 3, 2025, Public Service filed Rebuttal Testimony. Cross-Answer Testimony was submitted that day by UCA and MCC.

12. On July 29, 2025, following a Partial Variance granted by Decision No. R25-0548-I to allow the Parties more time to negotiate, the Company, Staff, CEO, MCC, Sierra Club, and SWEEP (collectively, the "Joint Movants") filed a Joint Motion to Approve Comprehensive Nonunanimous Settlement Agreement ("Settlement Motion") pursuant to Commission Rules 1400 and 1408 of the Commission's Rules of Practice and Procedure, 4 CCR 723-1. The Company, on behalf of Joint Movants, concurrently filed a Comprehensive Settlement Agreement ("Settlement Agreement" or "Settlement"). The Company, Staff, MCC, Sierra Club, and SWEEP each separately filed settlement testimony supporting the Settlement. UCA opposed the Settlement Motion and the Settlement Agreement. CEC did not oppose the Settlement.[1]

13. On August 12-13, 2025, Hearing Commissioner Gilman convened an evidentiary hearing, during which UCA cross-examined witnesses and Hearing Commissioner Gillman questioned certain witnesses. Hearing Exhibits 111 Rev. 1, 111C Rev. 1, 404, 405, 406, 412, 413, 420, 421, 422, 424, 425, 426, 427, 428, 429, 430, 431, 432, 433, 434, 437, 439 and 1000 (and all the listed exhibits therein) were offered and admitted into evidence.

[1] At the time of Settlement Motion filing CEC counsel did not have client approval regarding the Settlement and recommended to CEC that it not oppose the Settlement Motion or the Settlement. CEC counsel clarified at Hearing that CEC does not oppose the Settlement, *see* Hr. Tr. August 12, 2025, pp. 13:17-23.

14. On September 12, 2025, the Company, Staff, MCC, Sierra Club, and SWEEP filed a Joint Statement of Position urging the Commission to approve the Settlement Agreement without modification and reject the UCA's objections to the Settlement. UCA filed a Statement of Position on the same day urging the Commission to reject the Settlement and CPCN application outright but raised other issues for the Commission to consider should it approve the Application. CEO and MCC also separately filed individual Statements of Position.

II. APPLICABLE LAW

15. The Commission's authority to regulate Public Service's rates, services, and facilities derives from Article XXV of the Colorado Constitution. The Commission is charged with ensuring the provision of safe and reliable utility service at just and reasonable rates for customers pursuant to §§ 40-3-101, 40-3-102, 40-3-111, and 40-6-111, C.R.S.

16. Accordingly, Public Service filed its application for approval of the Mountain Energy Project and associated CPCN pursuant to 4 CCR 723-1-1303, 4 CCR 723-3-3002, 4 CCR 723-4-4002, and 4 CCR 723-4-4102 of the Commission's Rules, as well as § 40-5-101, C.R.S.

17. As the proponent of a Commission order, Public Service has the burden of persuasion in this proceeding pursuant to 4 CCR 723-1-1500 of the Rules of Practice and Procedure.

18. The evidence must be "substantial evidence," which the Colorado Supreme Court has defined as: "such relevant evidence as a reasonable [person's] mind might accept as adequate to support a conclusion ... it must be enough to justify, if the trial were to a jury, a refusal to direct a verdict when the conclusion sought to be drawn from it is one of fact for the jury." *City of Boulder v. Colorado Public Utilities Commission*, 996 P.2d 1270, 1278 (Colo. 2000)

(quoting *CF&I Steel, L.P. v. Public Utilities Commission*, 949 P.2d 577, 585 (Colo. 1997)). The preponderance standard requires the finder of fact to determine whether the existence of a contested fact is more probable than its non-existence. *Swain v. Colorado Department of Revenue*, 717 P.2d 507 (Colo. App. 1985). A party has met this burden of proof when the evidence, on the whole and however slightly, tips in favor of that party.

19. The Commission encourages settlement of contested proceedings, *see* Rule 1408(a), 4 CCR 723-1, though in considering settlement agreements the Commission maintains its independent duty to determine whether the terms of the settlement are in the public interest. *Cf. Caldwell v. Public Utilities Commission*, 692 P.2d 1085, 1089 (Colo. 1984).

III. EVIDENCE, ARGUMENTS, FINDINGS, ANALYSIS AND CONCLUSIONS

A. The Mountain Energy Project

20. The MEP is a hybrid portfolio proposed to address a gas supply constraint in the Company's EMGS. The Project consists of a non-pipeline alternatives ("NPA") portfolio as well as compressed natural gas ("CNG") and liquefied natural gas ("LNG") supplemental supply. As part of its Application, the Company requests the Commission grant a CPCN under § 40-5-101, C.R.S. and 4 CCR 723-4-4102 for the CNG and LNG supplemental supply components of the Project.

21. The EMGS serves a number of mountain communities including Grand Lake, Granby, Winter Park, Dillon, Frisco, Copper Mountain, Breckenridge, and Leadville. Public Service explains that the EMGS has limited supply resources due to its location and relies on supply from the Marshall Compressor Station, which feeds gas from the Company's Northern Gas System and Denver Gas System. Public Service states that as customer demand increases in

the three systems, a supply shortfall has affected the Grand Lake, Keystone, and Breckenridge load centers.

22. The Project as proposed in the Application is designed to avoid the construction of large-scale gas infrastructure by proposing a large non-pipeline alternative portfolio, compressed natural gas and liquefied natural gas supplemental supply, and electric infrastructure upgrades. More specifically, the Project includes NPAs consisting of gas Demand-Side Management ("DSM") measures and Beneficial Electrification ("BE") measures offered in targeted areas, where all measures are intended to reduce design day peak hour gas demand. The BE portfolio requires electric system upgrades, such as feeder upgrades in Leadville, a new feeder in Dillon, and transformer upgrades at the Breckenridge substation. The proposed CNG and LNG facilities (in Keystone and Breckenridge) will continue to be required to fully resolve the supply constraint.

23. The Project extends through the 2033-2034 heating season with respect to the DSM and BE measures. The CNG and LNG will be deployed in 2025 and 2026, and the electric upgrades will be placed in service between 2027 and 2029. In the Application, Public Service estimates the cost of the MEP to total $155.3 million.

B. Settlement Agreement

24. The Settlement Agreement addresses matters including the near-term NPA budget, implementation and cost recovery, acceleration of the Company's Residential Electric Heating Rate Pilot, a CPCN for five (5) tanks of LNG in Breckenridge, with a notice provision for additional LNG tanks and CNG in Keystone, cost responsibility, future evaluation of multiple base rate areas, outreach, reporting charges for LDCs in the event they increase capacity requests,

deferral of $1.6M in consultant and outreach expenses, as well as annual reporting no later than May 30 annually in the instant proceeding.[2]

25. A key feature of the Settlement Agreement is the Interim Regulatory Filing intended for further Commission review and approval of updated planning assumptions, changes to forecasting methodology, changes to design day methodology or temperature value, updates to the cost-benefit analysis framework or any other material changes analysis supporting non-pipeline alternatives ("NPAs") methodology. More specifically, on or before December 1, 2028, Public Service will submit in this Proceeding for Commission review and approval of: potential pathways forward for NPA implementation; potential pathways forward for supplemental supply resources, including CNG, LNG and the potential to repurpose or sell supplemental supply resources if and when they are no longer needed to meet supply shortfalls on the EMGS; and a Company proposal regarding future NPA portfolio cost recovery and responsibility in alignment with any different method adopted by the Commission.

26. Notably, the Settlement Agreement requires the Interim Regulatory Filing to include an updated forecast of the supply constraint in the EMGS, including incorporation of any updated planning assumptions, changes to forecasting methodology, changes to design day methodology or temperature value, updates to the cost-benefit analysis framework or any other material changes to the NPA analysis methodology or framework ordered by the Commission. The filing will also report on and incorporate performance of the NPA portfolio implementation to date. In addition, Public Service will include information about how and whether any other planned projects or interim CPCNs, including those in the most recent GIP, are interrelated with the forecast of the supply constraint in the EMGS. The Interim Regulatory Filing will also include

[2] Hrg. Ex. 116, Comprehensive Settlement Agreement.

an updated electric peak load forecast on geographically-relevant feeders and substation transformers to understand the electric distribution capacity available to support NPA adoption, as well as information to allow parties and the Commission to compare what was originally forecasted to actual measured data.

C. Statements of Position

27. CEO supports the approval of the Project and the associated Settlement Agreement, viewing the project as a nation-leading example of hybrid decarbonization. CEO commends the NPA Portfolio's scale and cost-effectiveness, as well as the project's alignment with state decarbonization goals and the state's emerging clean heat framework. CEO emphasizes that the Settlement builds on years of collaborative planning and implementation of non-pipeline alternatives, and highlights the value of deferring certain elements such as the full deployment of LNG facilities and portfolio selection until further data on NPA performance becomes available. CEO states that the Settlement prudently balances reliability, customer affordability, and emissions reductions, and urges the Commission to approve it without modification.

28. The Mountain Community Coalition, representing local governments in Summit County, supports approval of the Settlement Agreement. MCC expresses strong support for the NPA Portfolio, the Company's community engagement, and the comprehensive planning undertaken in the proceeding. MCC describes the Settlement as a thoughtful compromise that includes essential reliability infrastructure, while preserving flexibility for future planning based on the performance of the NPA programs. MCC also notes the community's preference to avoid traditional gas infrastructure expansion, and appreciates the accelerated timing and local focus of the proposed NPA investments.

29. In its Statement of Position, UCA advocated that the Commission find the Settlement is not in the public interest. UCA also recommended that the Commission deny the Company's CPCN application for CNG and LNG facilities and deny the NPA portfolio due to uncertainty surrounding NPA adoption levels in the EMGS. Further, throughout this Proceeding, UCA encouraged the Commission to apply an MEP "hookup fee" and rider to allocate MEP costs to cost causers.[3] .UCA also contends that the Settlement inappropriately defers key decisions to future filings and lacks meaningful cost controls. UCA also advocated for other positions should the Commission approve the Settlement Agreement and the MEP CPCN for CNG and LNG supplemental supply, including prohibiting the Company from capitalizing outside attorney fees into MEP projects.[4]

30. In part, UCA's opposition to the Project and to the Settlement Agreement arises from the fact that UCA views the Project as unnecessary. It criticizes the assumptions in Public Service's design day methodology and suggests the methodology is based on temperatures that are unrealistic or unlikely to occur and were selected with a dataset that its witness Mr. Skluzak views as arbitrary.[5] These flaws, according to UCA, result in unrealistic forecasts that support the need for the MEP yet do not reflect real world conditions. UCA points out that it has gotten quite cold in the EMGS, reaching twenty-six degrees below zero in 2025, and still Public Service did not need to use supplemental supply to stabilize the system at that temperature.[6] UCA also makes the point that Public Service's claims of potential injury to customers may be overblown; after all,

[3] Hrg. Ex 401, Skluzak Answer Tesimony, at pp. 18.
[4] UCA Statement of Position, at pp. 41-42.
[5] Hrg. Ex. 401, Skluzak Answer Testimony, at 41:7-8.
[6] Hr. Tr., 8-12-25, at 196:19-197:22.

Public Service could provide no evidence of injuries or death in the past ten years that resulted from natural gas outages on Public Service's gas system.[7]

31. The Joint Statement of Position, filed by Public Service, Staff, the MCC, the Sierra Club, and SWEEP, urges the Commission to approve the Settlement Agreement without modification. The Joint SOP emphasizes that the Settlement strikes a reasonable balance among competing priorities: ensuring near-term gas supply reliability, advancing non-pipeline alternatives, and avoiding costly infrastructure investment. The Settling Parties argue that the Settlement reflects good-faith negotiation, has broad support from diverse stakeholders, and includes robust reporting and oversight provisions to support Commission review in future filings. The Joint SOP also responds to UCA's objections, stating that UCA's proposed alternative would delay critical infrastructure and undermine the practical compromises reflected in the Settlement.

D. Discussion, Findings, and Conclusions

32. We begin by noting that this Proceeding arises during a period of transition for both the state's energy policy objectives and the planning paradigms that underpin the natural gas system. For much of the past century, planning practices that resulted in system capacity beyond immediate needs were generally viewed as prudent and did not render rates unjust or unreasonable. A modest level of overbuilding was often considered beneficial. It reduced the likelihood of service constraints as demand grew and potentially avoided greater long-term capital expenditures. However, as the state's energy goals have evolved and market competition from efficient electric heating equipment has emerged, demand uncertainty has increased. Now, such imprecision in system planning may be more likely to create stranded costs than long-term savings.

[7] Hrg. Ex. 428, PSCo Response to UCA DR No. 12-14(b) and (d); Hr. Tr., 8-12-25, at 198:3-200:3.

The Commission therefore expects utilities to adopt more rigorous and targeted planning and sizing methodologies to ensure investments are right-sized to future needs, recognizing the inherent risks associated with oversizing, just as it does with under sizing. The Interim Regulatory Filing within the Settlement Agreement aligns with this evolution of gas utility investments.

33. It is further important to underscore that, although the details of the methodology have been challenged, we do not have in this record alternate calculations or conclusions that show the risk is zero or a reliable alternative value of the shortfall. The Company has provided significant information in this record to underpin their concern for capacity constraints in portions of their system. Given the complications, expenses, and potential danger particular to natural gas outages, we have historically exercised great caution to ensure claims of reliability concerns by the Company were addressed. Avoiding such events through localized storage capacity provides tangible reliability benefits and reduces costs that would otherwise be borne by ratepayers in outage recovery efforts.[8] At the same time, the Company has taken a substantial step here to evaluate alternatives and express a flexibility in its approach to immediately deploy risk mitigation strategies in the short term while also planning for considerable upcoming changes to how some of these planning parameters might be evaluated in the future. This project has far-reaching implications in furthering understanding of alternatives to expensive traditional infrastructure and tracking key performance and implementation information. Ultimately, despite lingering concerns about some details of the calculations: (1) Company data indicate that there is a real risk to the system; (2) this record lacks compelling evidence from another party that there is no risk to customers: and (3) the MEP constitutes a reasonable no-regrets strategy to pursue innovative NPA solutions that have been widely supported by this Commission. It is further important to underscore

[8] Hrg. Ex. 102, Direct Testimony of Grace K. Jones, Rev. 1, pp. 41:4-41:9 and associated footnote.

that reliability remains the responsibility of the utility and the expectations for planning are in the midst of a transition.[9]

34. With that said, the Settlement Agreement takes a reasonable near-term approach, especially considering that the need to endorse a portfolio with a greater reliance on NPA measures versus supplemental supply is largely irrelevant until about 2030 and that it provides the Interim Regulatory Filing that will foster improvements in forecasting, planning, and ultimately investment decisions going forward. Given no divergence in the MEP pathways prior to that point, the Interim Regulatory Filing is a commonsense way to ensure that progress is on track and that the next steps of implementation are as well informed and strategic as possible. It is also a reasonable approach to begin implementation of the NPA portfolio immediately, given the immediate shortfall concerns expressed by the Company in the area.[10] However, several areas of the Settlement Agreement either require additional clarification or modification to ensure it is in the public interest.

35. This Proceeding has illustrated that it is difficult to pinpoint with mathematical precision the real world risk of a design day event occurring in the next few years, as well as predict the real world harm that would occur should such an event take place. In essence, what we are considering in this Proceeding is whether Public Service's evidence points to an increasing *risk* of

[9] Hrg. Ex. 117, Settlement Testimony of Jason Pequet, pp. 23:5-23:21. For further background on changes to the Company's gas planning and forecasting, *see* Decision No. R25-0083 issued in Proceeding No. 24M-0261G.

[10] The Company provided aggregate estimated supply shortfall data using existing forecasting and modeling strategies showing a growing shortfall from 2024-2033 for Breckinridge, Keystone, and Grand Lake, *see* Hrg. Ex. 102, Direct Testimony of Grace K. Jones, pp. 45:14-56:9. The Settlement Agreement acknowledges a supply constraint in the EMGS, and, through the Interim Regulatory Filing, provides the Commission the opportunity to review an updated supply constraint estimate utilizing any planning and forecasting methodology changes ordered in the ongoing Gas Infrastructure Plan Proceeding (Proceeding No. 25A-0220G), *see* Settlement Agreement, at ¶ 14.

failure on the EMGS, and whether that increased or increasing risk warrants approval of the Project as modified by the Settlement Agreement.

36. As recognized by the provisions in the Settlement Agreement related to the Interim Regulatory Filing, there is little doubt that the design day modeling presented in this case can be improved in the future. This Decision acknowledges UCA's critiques of the design day methodology and we raise additional concerns with the methodology as well. But at its core, we find persuasive the testimony indicating that there is a calculated supply shortfall even at temperatures above -39°F, including analysis the Company provided in its Rebuttal case that identifies a need for supplemental supply at multiple warmer design day temperatures using differing methodologies proposed by intervenors.[11] While there are some concerns and differences of opinion about their exact methodology, no party has provided an acceptable alternative methodology or disproven the existence of some shortfall on the system in the EMGS, which requires us to take the need for mitigative actions in that area seriously. That Trial Staff, the MCC, Sierra Club, and SWEEP also agree there is a need for this project reinforces our confidence in this conclusion.

37. Concerns that the supply shortfall is increasing and should be addressed as proactively as possible, allowing for the implementation of alternative methods like NPA measures, means that we see value in some of the approaches that the Settlement provides and that UCA disagrees with. For example, we acknowledge UCA's critiques around the NPA portfolio: the uptake rate is unknown, and there exists the possibility that the entire budget could be spent in under four years. But if the NPA portfolio is successful, it can mitigate much of the stranded asset concerns that the UCA and Commission share. And because this is a relatively new approach to

[11] Hrg. Ex. 111, Rebuttal Testimony of Grace K. Jones, Rev. 2, at pp. 83-93.

avoiding traditional infrastructure buildout there is bound to be some uncertainty in uptake and therefore in impact. Still, NPA projects offer the possibility of reducing stranded assets in the future. The sooner this Commission and stakeholders can begin to refine NPA approaches the more valuable those approaches will be, and the more places they can be deployed. The potential benefits both to the EMGS and to the development of these approaches in general outweigh the uncertainty that UCA highlights and that we all acknowledge. While we have not adopted UCA's proposal to remove the 15 budget flexibility suggested in the Settlement Agreement, we have set forth expectations around the effectiveness of the program in dollars per savings, below.

38. As well, we understand UCA's concerns that the Settlement Agreement "kicks the can down the road" in some respects. However, during a transition, a deliberate and iterative approach is preferable, and care is necessary given the growing risk of a supply shortfall in extreme conditions; it is thus better to start moving to mitigate that risk now. This is especially important since the NPA measures may take longer to materialize, so it is crucial to pursue them soon after a potential shortfall has been identified to avoid the significantly more expensive infrastructure solution. The Settlement Agreement, while not perfect, is a path towards risk mitigation that has support from the affected communities, avoids traditional infrastructure buildout that would come at far greater cost (reducing the magnitude of stranded asset risk), and represents an important step forward in designing NPA approaches that can help further reduce stranded asset risk in the future. More information will come in the Interim Regulatory Filing, and the parties and Commission can refine and learn from the results of this initial NPA portfolio.

39. As UCA points out, the overwhelming majority of the costs for the MEP will be allocated to all of Public Service's ratepayers, rather than primarily to those ratepayers in the

EMGS who are disproportionately causing the need for these infrastructure upgrades.[12] While we disagree that § 40-3-121(b), C.R.S. (which is now repealed) required the Commission to adopt base rate areas or otherwise allocate costs differently than has been done in the past for this system, we do appreciate UCA's advocacy for revising cost allocation. As such, we fundamentally agree with UCA that allocating costs to the customers that are causing them would provide better price signals for customers choosing between electric and natural gas options and, over time, might also encourage customers to invest in locations that don't require significant upgrades to the gas system. Moreover, better allocating costs to the customers that cause the infrastructure upgrades instead of socializing them across all customers may also help put downward pressure on overall rates, while also enabling strategic electrification by sending accurate price signals about the cost of gas infrastructure upgrades. While it may be premature to develop base rate areas or otherwise set fixed hookup fees for new EMGS customers in this proceeding and on this record, we hope that our expanded discussion in this Decision encourages UCA to continue to be a thoughtful proponent of these and other new approaches as it would be the Commission's intent to explore these issues in more detail in the upcoming natural gas rate case. If the Commission does move toward more localized cost allocation, either as base rate areas, as suggested to be studied by the Settlement Agreement, or as system impact fees for new customers, as explored by the Commission's order early in this proceeding, such an approach needs to be well thought out and applied to the entirety of the system, rather than focused on only one geographic area for this special treatment. The reality is that there are likely still many problems to be solved before base rate areas or other geographic cost allocation approaches can be applied in a fair, durable and analytically accurate way on a system that historically has not operated in that way. While we share UCA's serious

[12] UCA Statement of Position at pp. 11-12.

concerns about the extreme costs of this project triggered by a relatively amount of growth, this change in approach should be fairly applied in localized areas across the service territory. Although the Settlement Agreement does provide a limited (and slow) step forward on this point as Staff and Public Service (and any other interested settling party) have agreed to develop a scope of work for a third party to evaluate the need for and feasibility of multiple base rate areas, the Commission agrees that approaches for better allocating the costs of growth to those customers that cause it should be looked at more quickly and in further detail in the next rate case.

40. Finally, while we do not address UCA's remaining contentions point-by-point in this section, we have addressed the same issues UCA raises with the discussion and modifications to the Settlement Agreement that we set forth below.

1. NPA Portfolio: Implementation, Measures and Cost Recovery

41. We specifically endorse the need to start implementation of the NPA portfolio immediately as a no-regrets option to alleviate the Company's shortfall concerns. This project is intended to solve an issue that has likely developed over decades and was not recognized by the Company until there was a serious risk to the system and its customers.[13] Additionally, the success of the NPA portfolio may well rely upon giving it time to reach local contractors and customers, so any additional delay would be problematic and fail to serve the best interest of the public.

42. Throughout the proceeding, MCC provided compelling rationale as to why the Company should include technologies that are most likely to be useful in the specific project area, instead of applying expectations from other climate areas without the significant proportion of hydronic heating systems prevalent in the mountain region. While the Company's agreement to investigate the potential for including air-to-water heat pumps in the NPA portfolio is progress, it

[13] Hrg. Ex. 700, Answer Testimony of Rick Brown, Rev. 1, at pp. 16-18.

is unclear what primary research or specific understanding they must gain that will take a full year from the date of the Settlement Agreement.[14] Given the high portion of hydronic heating systems in the impacted area for which this could be relevant as well as the Company's agreement to implement the NPA portfolio as soon as possible, it seems reasonable that July 2026 should be the absolute latest timing to expect full rollout of an offering for air-to-water heat pump incentives. We expect the Company can beat that deadline, as the quicker they develop a strategy more tailored to the actual area, the quicker they will have an opportunity to mitigate the risk of supply shortfall.

43. Additionally, the Company may be missing major opportunities to reduce peak system demand by not having a clear understanding of the end-uses of the system in the project area. MCC put forth credible information about the significant prevalence and unique operational characteristics of gas-fired snowmelt systems in the impacted area, which was largely discarded by the Company as being a load of importance due to a survey in a much wider geographic area, despite one of only three contractors interviewed identifying that the contractor installs snowmelt on 100 percent of their projects. The size and unique operational characteristics of snowmelt, which, as MCC points out, may be very unlikely to follow the linear trajectory associated with increasingly lower ambient temperatures down to -39F, appear to be of critical importance in the acute geographic area of concern to the Company. As such, the Company must undertake immediate outreach to customers in the impacted area with usage over 500 therms per month to determine customers with snowmelt, estimates of the end-use usage attributable to snowmelt, any usage trends unique to that set of customers, and controls options that might allow those customers

[14] Hr. Tr. August 14, 2025, at pp. 16:16-18:19.

to avoid adding snowmelt demand to the system in extreme low temperatures.[15] The Company should also consider piloting a small number of interval gas meters on these locations to specifically identify usage patterns of snowmelt systems correlated with ambient temperature, especially to identify if the usage trend for these properties follows the Company's assumed relationship as displayed on Figure SKJ-SD-2[16] identifying the relationship between gas usage and changes in ambient temperature down to extreme cold temperatures – a key assumption in the Company's Design Day Methodology.

44. The Company's assumptions around the peak demand savings associated with gas-fired boiler upgrades for premises with hydronic baseboard do not appear to be valid, as the Company acknowledged during the hearing.[17] The Company must exclude these types of rebates from their program to avoid spending funds on projects that don't achieve the necessary peak demand reductions.

45. With respect to the project budget, the Settling Parties agreed to an NPA budget of $48.7 million over the 2025-2033 period, with 15 percent aggregate budget flexibility and the possibility to utilize the entire budget in the 2025-2029 period. While the budget seems appropriate, it is important to recognize that the goal for the NPA portfolio should be to reduce peak demand on the system, rather to simply hit a certain level of spending. Therefore, we find it appropriate to highlight that the expected results are approximately 627.49 mscfh in peak demand savings over the entire budget,[18] with an approximate cost efficiency of $77,610.8/mscfh of peak

[15] MCC testimony indicates that either building code or other regulation already requires these systems to cut out at such low temps due to the possibility of immediately forming ice, *see* Hrg. Ex. 601, Answer Testimony of Kenji Takahashi, at p. 38.

[16] Hrg. Ex. 107, Supplemental Direct Testimony of Grace K. Jones, Rev.1, at p. 25.

[17] Hr. Tr. August 14, 2025, at pp. 27:25-30:13.

[18] Hrg. Ex. 102, Direct Testimony of Grace K. Jones, Attachment GKJ-10 (Public, PDF version) at p. 51.

demand savings. While the Commission does not wish to set a strict requirement for peak demand savings of the NPA portfolio, given the nascency of a program of this type, we do wish to express the intent that use of the budget flexibility should be targeted at achieving higher demand savings in association with the higher budget.

46. The cost recovery in the Settlement Agreement of splitting the cost recovery of NPA measures 50/50 between the Demand-Side Management Cost Adjustment-Electric ("DSMCA-E") and Demand-Side Management Cost Adjustment-Gas ("DSMCA-G") mimics direction from the Commission from the Company's initial Clean Heat Plan ("CHP").[19] While it is relatively easy to see why this appeared to be the path of least resistance for execution of the Company's first large NPA, the durability of this approach after this initial period through 2030 addressed in the Settlement Agreement will likely continue to be evaluated in future proceedings. In contrast to CHP investments, which help effectuate public policy goals, the direct and obvious goal of an NPA is to avoid investment on the gas system, specifically. Additionally, the premise of NPAs providing benefits to the Company's electric customers will likely require a sincere and strategic focus on minimizing peak demand impacts, as identified in several recent Commission decisions related to planning for the Company's electric system. The anticipated benefits to both the gas and electric systems justify the split proposed in the Settlement Agreement for the initial period, but should be revisited in the Interim Regulatory Filing based on progress on the issues identified herein.

2. Residential Electric Heating Rate Pilot

47. Given how important customer acceptance is to a successful NPA portfolio, this provision addresses an important potential economic incentive for electrification. However, given

[19] Proceeding No. 23A-0392G.

the statutory requirement associated with avoiding "cross-subsidies from other customers" for residential customers who utilize a heat pump as their primary hearing source,[20] the issues surrounding the proper modeling and use of real data to identify operations of heat pumps, especially in peaking conditions, will be crucial to a proper later adjudication of this issue. The Company has fully deployed advanced metering infrastructure ("AMI") technology for their electric customers and should be capable of identifying, tracking and trending information associated with heat pump heating, in order to properly set up the cross-subsidization portion of the adjudication, rather than relying on overly broad and unverified data about the potential, rather than actual, performance of such equipment, especially related to peak electric system impacts. This data will be crucial for use in the analysis of proper Residential Electric Heating Rate Pilot tariffs and collection and analysis of such data should be a priority of the Company immediately, in order to ensure they have the information required to properly make a showing associated with the cross-subsidization issue in the filing that is now expected in July 2026.

3. Supplemental Supply

48. The Settling Parties agreed to the Company's requested CPCNs for the CNG and LNG supplemental supply components of the project while placing expectations around several other aspects of the supplemental supply deployment. The Company specifically requests a CPCN for this equipment. However, especially given the specifics of this proceeding, it is important to clarify what is being approved with respect to the supplemental supply. Overall, the Company's support for the ultimate sizing of its requested supplemental supply is less than perfect and receives significant focus in the Additional Findings section, below.

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[20] Section 40-3.2-110(2) C.R.S.

49. In addition to the underlying challenges buttressing the sizing, the budget for the supplemental supply resources is troublingly vague. By the end of the evidentiary hearing, it was clear that the Company had both purchased the actual LNG equipment to be used and had near certainty as to the site that would be used, which should lead to significant clarity about the cost of the land itself and the associated costs of site-specific mitigations. Despite this, the Company made no modifications to their cost certainty range of -50 percent to +100 percent of the stated budget. It is difficult to conceive of providing any presumption of prudence on an ultimate cost which is entirely unknown at this point. Additionally, given the agreement to the Interim Regulatory Filing in 2028 intended to chart the path for the long-term mix of NPA and supplemental supply, it is also difficult to apply CPCN expectations, which are typically for permanent infrastructure. Therefore, we find it important to clarify that in this proceeding, the Company will receive a Presumption of Need for the supplemental supply resources through the adjudication of the Interim Regulatory Filing beginning in 2028. This Presumption of Need is not accompanied by a Presumption of Prudence as to the costs of the supplemental supply. The Company should bring forth any costs for the supplemental supply to a future general rate case for review and determination of prudence.

50. Regarding the potential purchase and deployment of additional LNG storage tanks in Breckenridge prior to the Interim Regulatory Filing, additional clarification is also necessary beyond the language in the Settlement. The installation or acquisition of additional LNG past the initial five LNG tanks identified in the Settlement Agreement do not receive any finding of need in this proceeding and those costs will need to be presented for recovery in a future rate case proceeding. The Settlement Agreement does not identify the number of agreed to CNG tanks, but this is presumed to be two tanks, matching the Company’s Direct and Rebuttal case. The

Settlement Agreement lacks detail about what information will be provided in the notice to parties about the emergent needs identified by the Company. Given the Settlement's sidestepping of certain technical issues challenged in this proceeding, the sizing justification associated with any additional storage tanks should be evaluated seriously when Public Service seeks cost recovery for any additional tanks.

4. Cost Responsibility

51. The Settling Parties agreed to cost responsibility across the entire base of gas and electric customers. We agree that it is not feasible or fair to focus on recovery only in the geographic area for one specific project without considering such a standard for the rest of the system. However, this record provides a clear and concerning indication that the cost to add new load can vary widely across different parts of the system. This issue is compounded by the Company's failure to identify this emerging issue, for perhaps decades,[21] which may have limited options to mitigate or avoid such a significant expense which could have been achieved through more proactive planning. Nonetheless, a $155M project is jarring to see if that price tag indeed corresponds to service to a small segment of customers. Based upon the Company's reported 33,500 customers in the EMGS,[22] this would equate to approximately $4,627/customer. The Company points to growth over the past few years of approximately 8 percent, which the Company indicates caused the need for the project,[23] which equates to about 2,680 new customers. If the entire $155M project cost corresponds to service to these new customers, the result would be approximately $57,836 per new customer. It seems obvious that if the customers or communities were aware of such an extraordinary cost of adding customers in that area and properly

[21] Hrg Ex. 700, Answer Testimony of Rick Brown, Rev. 1, at pp. 16-18.
[22] Hrg. Ex. 102, Direct Testimony of Grace K. Jones, Rev. 1, at p. 3.
[23] Hrg. Ex. 102, at p. 44.

incentivized, other options, perhaps significantly cheaper, may have availed themselves. This proceeding thus illustrates the need for the Commission to reexamine established ratemaking and cost allocation practices at play on the Company's gas system, an issue the Commission should consider as a part of a Phase II Rate Case the Company must file by the end of 2025.[24] While the Settlement Agreement has a direction to begin investigating the feasibility of different rate areas, it is also possible that more locationally specific system impact fees for new customers, based on the upstream costs of additional capacity, should also be explored as an option.

52. The Settlement expresses agreement with the Company's proposed approach for charging other LDCs their proportional share of Project costs (other than electric infrastructure costs) in the event their respective increased capacity requests are fulfilled. This provision is reasonable and can provide appropriate cost allocation to increases in transportation capacity related specifically to LDCs. However, LDCs represent only a narrow subset of transportation customer capacity needs and growth on the EMGS. The broader issue of transportation customer capacity impacts and cost responsibility for the MEP have not been addressed by the Settlement Agreement. With no cost responsibility through the DSMCA-G, transportation customers, whose capacity needs are addressed through firm requirements on the EMGS, are likely to not have cost responsibility for the costs of the project, despite the same capacity guarantees as retail customers. While there may be some costs borne by those transport customers who are also the Company's electric customers, they would only be covering a portion of the costs through those surcharges, despite any increases in their design day needs being just as impactful on the system as increases for retail customers. Therefore, we order in the Company's next Phase II Gas Rate Case that the Company propose a charge on shippers for proportional cost responsibility, in an analogous

[24] Hr. Tr. August 14, 2025, at 48:12-49:11.

manner to the LDC charge in the Settlement agreement, upon fulfillment of a shipper's request for more capacity in the EMGS.

53. At hearing, the Company indicated that outside attorney fees are included in the capital costs of the MEP and the Company would be "indirectly" entitled to a WACC return on such fees.[25] Further, the Company could not point to where the outside attorney fees were provided in the record of this Proceeding. In its Statement of Position, UCA observed that, "a utility's capitalization of outside attorney fees into proposed capital investments is highly unusual if not unprecedented."[26] Regardless of whether the practice of including outside attorney fees is new or established, we agree with UCA that the Company may not seek to incorporate outside attorney fees within the capital costs of the MEP but may include outside attorney fees as a part of the non-interest-bearing regulatory asset established as a part of the Settlement to allow deferral of consultant and outreach expenses to be brought forward to review and recovery in a future rate case.[27]

5. Reporting

54. The Settling Parties agreed to certain reporting, due annually by May 30 during NPA implementation, to be filed in this Proceeding. The reporting primarily focuses on the need for and use of supplemental supply in the prior year, the need for electrical updates at customer premises to support electrification and update on the residential electric heating rate pilot and associated rate impacts on those customers' bills. Having access to fulsome reporting that provides insight into this first-of-its-kind project will be crucial to understanding key aspects of the Interim

[25] Hr. Tr. August 14, 2025, at pp. 85:1-86:9.
[26] UCA Statement of Position, at pp. 40.
[27] Hrg. Ex. 116. Comprehensive Settlement Agreement, at pp. 5.

Regulatory Filing that will be made no later than December 1, 2028, as well as NPA potential and impacts of electrification more broadly.

55. In several recent proceedings including the Company's Clean Heat Plan, Gas Infrastructure Plan, Distribution System Plan and Just Transition Solicitation, the assumptions used to derive the peak capacity impacts of beneficial electrification on the electric system were shown to be a driver of significant capital investment and also were the subject of disagreement among the parties as to what assumptions were the most appropriate. With AMI infrastructure fully deployed on the Company's electric system, the Company should be readily able to track electric usage and demand impacts for participating customers which should be immensely helpful in fine-tuning assumptions in both the interim filing in this matter, as well as a variety of other planning proceedings. In many cases, these values have been calculated based on assumed worst-case performance, rather than observed from actual performance, given that the Company's beneficial electrification efforts are relatively new and actual customer usage impacts have not been closely studied.

56. Given this, we find it necessary to expand the reporting to include monthly electricity and gas usage for at least one year of customers that participate in the NPA portfolio, and usage of the same customers for a full year prior to their participation in the NPA portfolio, as requested by CEO.[28] Customer identification and premise can be reasonably anonymized to avoid privacy concerns. Additionally, the Company's claims in rebuttal to this reporting being "voluminous" and administratively burdensome are without merit, as the Company provides no rationale why, given the IT solutions and analytical capabilities available to them, this should be a manual or arduous exercise. Such concerns do not override the public interest need in collecting

[28] Hrg. Ex. 300, Answer Testimony of Jocelyn P. Durkay, at pp. 49:36-50:2.

essential data to plan and right-size the future system. Instead of resistance, we would expect the Company to welcome analysis of such data to enable them to plan the system, inclusive of significant amounts of electrification, in a way that minimizes uncertainty and optimizes investments in right-sizing infrastructure.

57. Additionally, in rebuttal, the Company agreed to track LNG/CNG cumulative costs for evaluation in a future gas rate case where those facilities are proposed to be placed into rate base.[29] To clarify, the Company should track the costs of LNG and CNG facilities, as well as their associated O&M costs, separate from each other such that the total cost of the LNG facilities and total cost of the CNG facilities may be compared to their estimates. Given that deployment of these types of supplemental supply are relatively new for the Company, especially regarding LNG, understanding the costs associated with each type, rather than an aggregate, is necessary.

6. Cost Benefit Analysis

58. Notably, the Company's approach on the cost benefit analysis does not include all aspects of those directed in Decision No. R25-0083, which was issued in the Gas Infrastructure Plan proceeding. While this is likely a timing issue, since this Proceeding was initiated at very similar time to the conclusion of Proceeding No. 24M-0264G, those directives should be followed in the Company's Interim Regulatory Filing in 2028.

7. Conclusion

59. This Proceeding comes at a time of transition, both in the state's energy goals and perhaps more acutely in system planning approaches. Historically, planning imprecision that resulted in capital projects with additional capacity has not been found to result in unjust or unreasonable rates. One animating factor was likely that additional capacity could result in less

[29] Hrg. Ex. 110, Rebuttal Testimony of Jason J. Peuquet, Rev. 2, at p. 85.

capital spend over time, as future growth on the system could be accommodated by the additional capacity that was already on the system. However, as the state's policies have changed and we see increasing competition from efficient electric alternatives in the marketplace, this level of imprecision in the planning process may be less likely to serve future load than to result in stranded asset costs for ratepayers. As a result, our approaches to gas system planning must recognize this shift and should seek to undertake planning and sizing exercises with more precision than perhaps has been used in the past.

60. We are ultimately concerned with the reliability risks that have been discussed in this Proceeding. The growing risk of supply shortfall in the EMGS is a real and troubling issue. Though UCA challenges the need for the project, it is Public Service that bears the burden of providing reliable service to its customers. While we have also identified a need to improve the precision of these processes, there is no alternative analysis presented to provide us comfort that the shortfall identified by the Company does not exist and require immediate action. Based on this record, it appears that Public Service should have identified and addressed this problem long ago, and since it did not, we must now move quickly to mitigate the risk of supply shortfalls.

61. The modified Settlement Agreement puts into place an NPA portfolio that can reduce demand on the system and that will begin rollout now. It approves infrastructure that can backstop any supply shortfalls that occur during periods of extreme weather, which could be relocated to other systems needs in the future should the need in this area be effectively mitigated by the accompanying NPA portfolio. The balance struck by the Settlement Agreement results in an innovative NPA approach to reducing the risk of stranded assets, avoids a much more expensive traditional infrastructure project that could be at risk of being stranded, and aligns with the state's emission reduction goals. There is value in developing and implementing the type of NPA projects

that are part of the MEP, both to the affected communities here, as well as to the Commission and other stakeholders as approaches to gas system planning evolve. Therefore, this project and its novel approach are likely to have far-reaching benefits across the system, especially in learning and evolving the Company's NPA approaches which could carry the promise of limiting capital investment and stranded asset risk across the system, which are likely to be aided by the concentrated effort expected through implementation of NPAs for the MEP.

62. Finally, the Interim Regulatory Filing allows the Commission and stakeholders flexibility to tailor future approaches to shortfall risk that may be present in later years, especially considering the multitude of current uncertainties related to forecasting and planning on the gas system. The modifications made should incent Public Service to control costs and provide additional transparency surrounding the ultimate costs and efficacy of the programs and infrastructure approved today. Commissioner Gilman's thoughts and analysis attached to this Decision also serve to bolster our support for the Interim Regulatory Filing within the Settlement Agreement and a continuation of the discussion around gas planning approaches in other appropriate venues, like the Gas Infrastructure Planning proceeding. We appreciate that despite her strong critiques of the planning assumptions, forecasting and design day methodologies, she rendered an initial commission decision pursuant to § 40-6-109(6), C.R.S., that approves the Settlement Agreement and grants Public Service's Application as modified by that agreement, with further reasoned modifications as explained in this Decision.

IV. <u>ORDER</u>

A. The Commission Orders That:

1. The Comprehensive Settlement Agreement ("Settlement Agreement") filed on July 29, 2025, by Public Service Company of Colorado ("Public Service") is approved, with

modifications, consistent with the discussion above. The Settlement Agreement is attached to this Decision as Attachment A.

2. The Motion to Approve Settlement Agreement filed on July 29, 2025, by Public Service is granted, consistent with the discussion above.

3. The Application for Approval of the Mountain Energy Project and for a Certificate of Public Convenience and Necessity for Supplemental Supply filed on January 16, 2025, by Public Service, is granted as modified by the Settlement Agreement and by this Decision, consistent with the discussion above.

4. This Decision will constitute a Certificate of Public Convenience and Necessity for Public Service to construct, own, and operate the compressed natural gas supplemental supply and the liquefied natural gas supplemental supply components of the Mountain Energy Project, consistent with the findings and discussion in this Decision, until resolution of the Interim Regulatory Filing.

5. In accordance with the Settlement Agreement, Public Service shall file in this Proceeding an Interim Regulatory Filing no later than December 1, 2028.

6. The 20-day period provided for in § 40-6-114, C.R.S., within which to file an Application for Rehearing, Reargument, or Reconsideration, begins on the first day following the effective date of this Decision.

7. This Decision is effective upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING November 19, 2025.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

V. HEARING COMMISSIONER'S ADDITIONAL FINDINGS

63. In the hopes that it may accelerate conversations in future proceedings, the Hearing Commissioner has recorded her thoughts and analysis here on a variety of topics that the Commission is likely to encounter in the future, including its review of the Interim Regulatory Filing in 2028. These criticisms are examples of some of the shortfalls of the traditional gas planning process and are listed here as issues to be addressed as this process evolves. Nonetheless, the parties have reached a settlement agreement that underscores the parties willingness to take into account evolving methodologies or frameworks around forecasting at this point in time.

64. The record in this proceeding delved into several issues related to capacity planning, the Company's Design Day methodology and forecasted system needs. At its core, the issues in this proceeding were based upon the need calculations provided by the Company which implicated each of those categories of analysis. However, the Settlement Agreement largely leaves these foundational technical issues unaddressed except for the critical requirement on Public Service to submit the Interim Regulatory Filing. A significant amount of capital spending on capacity expansion projects is buttressed by the Company's Design Day methodology and the assumptions inherent to it. This proceeding probed into a localized example of such planning in more depth than many other proceedings. That said, despite a thorough examination of the assumptions underlying the Company's calculations and the shortfall calculation outcome, many questions remain about the appropriateness of many of these assumptions individually as well as the combination of each of the individual steps and assumptions when taken together, especially as we move forward in a transition with the gas system with the increased risk of excess capacity posing serious stranded asset risk. The record provided a basis for findings on these matters, which

will likely be useful as the Commission and stakeholders continue to examine forecasting and capacity needs with the Interim Regulatory Filing and in other proceedings.

A. System Planning

65. The circumstances surrounding the significant shortfall identified by the Company remain a major concern. In Rebuttal, the Company's witnesses at times discounted critiques of other parties by painting themselves as the most experienced in the area of gas planning and as the only party with certain obligations to fulfill. While some of this may be technically true, this seemingly cavalier attitude toward legitimate technical challenges is misplaced in the wake of such a major planning failure by the Company. Testimony that went undisputed on this record showed that the Company may have had a shortfall in the Breckenridge area dating back to 2,000, which was only identified by the Company for the first time in 2022.[30]

66. To make matters worse, this was not a typical situation with an easily deployable infrastructure solution. How the Company went on for decades, hooking up additional customers, without any reasonable understanding of the actual physical limitations of their system and the very significant costs that would be incurred once those limitations were fully exercised leads to valid concerns about the Company's planning abilities and processes. The lack of proactive planning that got us to where we are today has left this Commission and the affected communities with few options and no inexpensive ones.

67. The communities and their residents, through public comment, express legitimate concern with locating industrial quantities of compressed gas within their small communities. Unfortunately, by the time this issue was brought to the Commission it was many years, likely decades, past when we could have avoided the need for supplemental supply of gas, according to

[30] Hrg. Ex. 700, Answer Testimony of Rick Brown, Rev. 1, at pp. 16-19.

the Company's shortfall calculations. Through more proactive planning and fulsome calculations and disclosures related to the Commission's relatively new Gas Infrastructure Planning rules, we aim to avoid a situation like this in the future. However, the Company's attitude that no one can legitimately question their assumptions and the prudency of their planning has not been well supported on this record. In fact, this record points to a need to redouble our efforts to hold the Company accountable for proactive planning to ensure system costs can be optimized in the future and that all cost-effective options can be considered.

B. Design Day Methodology and Shortfall Calculation

68. The entire problem and set of solutions for consideration depend heavily on the size of the shortfall identified by the Company. The shortfall calculation is arrived at through several steps of calculation, including evaluation of the hydraulic modeling for the Company's Design Day temperature in the area, then layered with forecasted growth. Since the Company has not seen a temperature similar to the Design Day temperature used in over 60 years, they extrapolate out the anticipated relationship between ambient temperature and throughput. After determining the peak capacity need, they model the peak day and then run a Monte Carlo simulation to determine the storage capacity needed to serve the peak needs over a potential long duration extreme cold weather event. After sizing the storage, the Company includes some additional sizing allowances for redundancy.

C. Forecasting

69. The Settlement Agreement does not mention specific changes to its forecasting methodology, despite forecasting being a key input going forward. The Company's forecasting layers on top of their existing system conditions to determine shortfall calculations for years to come and the likelihood of different strategies like NPAs to be able to fill the need. Given the

Company's reliance on forecasting to determine the size of the shortfall in years to come, there is significant relevance to ensure that the Company is utilizing forecasts that appear to be the most appropriate and practical, given the entirety of the market options available to consumers and policy environment. Indeed, MCC and other parties highlighted local electrification efforts and building codes as having a likely impact to forecasts, particularly in the communities at the heart of the Mountain Energy Project.

70. The Interim Regulatory Filing in 2028 with reporting on progress and shortfall size is a good step to help identify if there really are noticeable changes in forecasting that should be used to adjust the Company's base assumptions. Additionally, the GIP M-docket, Proceeding 24M-0261G, included direction regarding forecasting that was not considered in the Company's approach in this Proceeding, perhaps due to the timing of the filing, but should be incorporated in future calculations. For example, the Company's base forecast used to model future year design day peak hour gas demand growth does not include any impacts of the Company's approved Clean Heat Plan,[31] and this base forecast was directly rejected in Decision No. R25-0083. The Company should, at a minimum, utilize any ordered changes to forecasting from the GIP M-docket and the upcoming GIP and CHP in the Interim Regulatory Filing.

D. Design Day Temperature

71. The only mention of Design Day Temperature appears in the Settlement Agreement around an agreement to run an alternative shortfall analysis at -33F. Parties submitted significant testimony related to the use of a Design Day Temperature of -39°F. Critiques included an acknowledgment that the probabilistic method employed by the Company leads to two extreme cold instances which occurred 63 and 74 years ago to continue to drive the selection of the Design

[31] Hrg. Ex. 111, Rebuttal Testimony of Grace K. Jones, Rev. 1, at pp 42:15-43:2.

Day temperatures. Unlike other system planning, like on the electric system where only the last 20 years of weather data are used, the Company here uses all available data and a probabilistic model which leads to a relatively high degree of relevance still being placed on data that is more than 60 years old and has not recurred since. Additionally, parties provided valid concerns about the appropriateness of the design temperature being used and the Company's unsupported assumption that it is reasonable to assume that the entire EMGS could experience such an extreme temperature concurrently. As such, it should be further pursued in the Gas Infrastructure Plan and other venues if use of the most significant outlier temperature that has been observed to affect only a portion of the EMGS may overstate the expected extreme cold across the EMGS.

72. In addition to the importance of the design temperature that is used, the relationship between expected throughput and the Company's design temperature is critically important. The system has grown considerably in the last 60+ years, leading to no direct comparison at the design temperature. In Direct Testimony, the Company claimed that they completed a verification process of the Design-Day As-Is model for the EMGS by comparing it to their Supervisory Control and Data Acquisition (SCADA) data.[32] However, when asked to provide such data in Supplemental Direct testimony, the Company's submission included just two dates from 2023, one with a low temperature of -7F and the other -15F.[33] Future exploration of the capacity planning process must include more relevant temperature validation at temperatures significantly closer to the design day temperature, if available. If not available, a more sophisticated modeling and justification for load behavior at the extreme temperature, rather than behavior of loads at relatively typical winter temperature, is necessary to aid in validation.

[32] Hrg. Ex. 102, Direct Testimony of Grace K. Jones, Rev. 1, at pp. 45:19-46:4.
[33] Hrg. Ex. 107, Attachment GKJ-15, at p. 2.

73. In Supplemental Direct, the Company also provided Figure GKJ-SD-2, which shows a Representative Residential Premise Curve.[34] However, the curve here displays information based on Heating Degree Days (HDD) and the Company has not provided any commiserate HDD information in the record, instead focusing on the potential daily low of -39F. Additionally, the Premise Curve HDD values do not appear to go to a level similar to what HDD would need to be evaluated for a day with a low of -39F. In Rebuttal, the Company also provided information from Saint Cloud, MN to show some correlation.[35] It is unclear what design temperature is used for buildings in the area nor how end uses may vary between Saint Cloud and the EMGS. The Company attempts to correlate these by identifying that the ASHRAE 99 percent heating dry bulb temperature for Saint Cloud is lower than that for the EMGS, but that leaves it entirely unclear why the example only focuses on a low of –28F for a location that the Company indicates has colder temperature data than EMGS, which utilizes a design temperature of -39F. Likewise, the Company argued that their Design Day methodology is sound because they utilize a -25F temperature for the Denver Gas System and in January 2024, the system recorded a temperature of -24F.[36] Again, the temperature being used in EMGS is far lower than this design temperature, so the relevance of this example is unclear. Additionally, the Company notably did not provide flow data with this recent example which was cited to display the soundness of their Design Day Methodology. While none of these examples pointed to there being no shortfall in the project area, which remains a concern given the only analysis on this record, they did little to aid in enhancing the Company's case. As we evaluate design day methodology and validation in upcoming proceedings, it will be essential for the Company to provide information relevant to the

[34] Hrg. Ex. 107, Supplemental Direct Testimony of Grace K. Jones, at p. 25.
[35] Hrg. Ex. 111, Rebuttal Testimony of Grace K. Jones, Rev. 1, at p. 82.
[36] Hr. Tr. August 14, 2025, at pp. 109:7-110:6

specific temperatures and usage profiles in the subject areas. An increased focus must be placed on evidence surrounding the expectations for capacity behavior at the extreme temperatures being modeled, rather than more moderate temperatures, which may not hold a high degree of relevance.

E. End-Use Data and Understanding

74. In order to ensure peak demand calculations are valid and to execute on the most strategic and cost effective ways to minimize the peak demand shortfall in the EMGS, this record indicates that the Company will need to make significantly greater attempts to accurately characterize the system end-uses, their behavior at extreme cold temperatures and strategies specific to reducing those peak demand impacts. MCC witnesses describe gas-fired outdoor snowmelt systems as being more prevalent than assumed by the Company, which could impact both the accuracy of assumptions about the behavior of those loads at Design Day conditions,[37] as well as opportunities to specifically target such large loads for demand response or other programs to reduce or eliminate their contributions to the Design Day needs.[38] Therefore, it is imperative that the Company make it a priority to swiftly identify customers that are likely snowmelt users, attempt to better understand the operation of the systems at extreme cold conditions and develop a suite of strategies to specifically address either demand response or alternative sources for these discrete, large snowmelt loads. The Company should update MCC and the other stakeholders on the progress on this outreach and research regularly in the stakeholder process. MCC Witness Takahashi also identified the potential lack of consideration for operation of building space heating at extreme cold conditions, identifying that the local building code standard for sizing such equipment is based on an outdoor temperature of -13F. The Company does not make a logical

[37] Hrg. Ex. 601, Answer Testimony of Kenji Takahashi, at pp 38:3-38:15.
[38] Hrg. Ex. 600, Answer Testimony of Jesssica Burley, at pp. 16-18.

argument against such an issue, essentially by articulating an assumption that every mechanical system may be so dramatically oversized that it demands more gas all the way down to -39F. While oversizing likely occurs to some degree, as was admitted by Takahashi, the Company's version of there effectively being no limit to the oversizing, even in a portion of building, down to a temperature not seen in more than half a century is a leap not supported by data or common sense.

75. The Company must endeavor to understand how equipment sizing impacts the slope of the relationship between ambient temperature and system demand at the sort of extreme temperatures being used for their Design Day methodology. Perhaps the proactive role that MCC is playing in this proceeding could open up opportunities for the Company to learn some of this information from building departments and energy professionals who are more familiar with or have records of equipment sizing for a decent volume of properties, which could refine these estimates to be based upon assumptions with a more appropriate basis. Importantly, these assumptions have far reaching implications beyond the MEP, as these extreme cases of assumed usage are then converted to electrical capacity requirements for many of the Company's assumptions about electric system impacts, which may be overstating the electric needs and costs associated with electrification of the space heating loads.

F. Storage Sizing Monte Carlo Simulation

76. The steps above are used to determine the instantaneous shortfall at the Company's Design Day condition. In Direct Testimony, the Company indicated that the onsite storage volume was calculated by doubling the daily volume of gas needed for design day. In Supplemental Direct, the Company was ordered to provide additional testimony on the rationale or basis for doubling the daily volume. The Company responded that they conducted a Monte Carlo simulation to

identify the possible duration of an extreme cold weather event, eventually basing the sizing of the needed storage capacity on 48 hours of assumed continuous cold weather.[39] The Company identifies that it had to make modifications in this simulation since hourly data is only available for a Copper weather station, not the Dillon location used for the Design Day temperature. Additionally, this simulation could only be done at a temperature of -9F where sufficient data points existed. The Company argued that it is typically about 8 degrees colder in Dillon than Copper, concluding that this essentially models a -17F condition in Dillion. In upcoming proceedings, the Company must provide additional insight into the correlation of temperatures used for the design day and those used for the modeling underpinning the expected duration of such an event. Additionally, a comparison of the correlation of extreme cold weather events across each planning zone could provide important insight into the validity of some of the key temperature assumptions as we continue to improve upon planning processes.

77. The Company determined that planning to a 99.6 percent likelihood for the cold weather event duration was the most appropriate, but it is not clear upon what that planning criteria was based. The Monte Carlo Simulation shown in Figure SKJ-SD-1 has a long tail of very low probability runs with the 99 percent probability of an event colder than -9F lasting 20 hours or shorter.[40] A critical question in planning our infrastructure is to what point of certainty systems should be sized for. This should be addressed in upcoming proceedings to allow for more refinement of the system planning, including a cost benefit analysis of minor improvements in probability and the related costs for such improvements. In this case, the differential between planning to a 99 percent probability and a 99.6 percent probability has likely doubled the storage

[39] Hrg. Ex. 107, Supplemental Direct Testimony of Grace K. Jones, Rev. 1, at pp. 13:10-15:4.
[40] Figure GKJ-SD-1, Hrg. Ex. 107, Supplemental Direct Testimony of Grace K. Jones, Rev. 1, at p. 15.

capacity of supplemental supply (from 20 hours to 48 hours). Ultimately, though, in this Proceeding, this particular critique gets more of the sizing of the supplemental supply, rather than its existence. While the current approach likely requires additional refinement in the future, we do not have an alternative sizing analysis in this record, thus recommend moving forward with the Settlement Agreement, as modified, and taking the learnings of this Proceeding forward to further vet more precise alternatives to this methodology.

G. Additional Oversizing of Storage Equipment

78. Finally, after completing the above steps, the Company selected storage volumes for the proposed supplemental supply. In Keystone, the Company identified that 528 mscf of CNG storage was necessary.[41] The Company plans, as part of the MEP, to install two- 450 mscf CNG trailers,[42] totaling 900 mscf of storage in Keystone, 70 percent more than the storage volume they determined to be needed. When asked in hearing about such a dramatic oversizing, the Company responded that the reason for the volume being installed in Keystone was "not due to the volume" but rather because "We like to build redundancy into our system."[43] Despite the availability of smaller tanks[44] that could better fit the need and still provide some redundancy, the Company for the first time in hearing indicated that they wanted the entire storage volume to be able to be served by one tank and intentionally added an entire additional tank for redundancy in case of a failure. However, the Company does not have any experience with issues with any CNG pieces of equipment which they could point to[45] in support of the need for 100 percent redundancy. It will be critical in future proceedings to better understand the Company's sizing assumptions and to

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[41] Hrg. Ex. 102, Jones Direct, at p. 166.
[42] *Id.*
[43] Hr. Tr. August 14, 2025, pp. 75:10-75:23.
[44] Hr. Tr. August 14, 2025, pp. 76:1-76:4.
[45] Hr. Tr. August 14, 2025, pp. 77:16-77:20.

identify an appropriate level of risk, inclusive of redundancy concerns, which were not well explored on this record.

79. While not as dramatic, the Company's LNG application in Breckenridge also appears to be oversized with the storage need identified by the Company of 4,492 mscf and 5 LNG tanks amounting to 5,369 mscf of storage,[46] which is nearly 20 percent larger than the identified need. The Company does not identify the same redundancy concerns with LNG since the Company plans to have multiple tanks, vaporizers and pumps already.[47] The Company's Direct case seemed to be based on an assumption of including up to eight (8) LNG tanks. The compromise to five tanks appears to be a key consideration for several intervenors, however, it is not clear at all upon what evidence the Company planned to substantiate the need for eight tanks. The approach to redundancy and sizing of the actual storage equipment based on planning and risk tolerances will require further inquiry to the extent the Company plans to deploy supplemental supply in the future.

80. Despite these critiques of the Company's capacity and sizing calculations, the Project provides a critical step forward in implementing a major NPA portfolio and evaluating important avoidance techniques to reduce the risk of stranded assets from traditional gas infrastructure. Since this Proceeding delved further into many more of the precise planning standards and calculations than previous proceedings had, there are not specific adjustments or alternative calculations that could be pointed to on this record to identify that no shortfall exists or to resize the portfolio based upon the concerns. Given that, the most pragmatic approach forward, which is supported by this record, is to move forward with the no-regrets NPA portfolios supported

[46] Hrg. Ex. 102, Jones Direct, at p. 168.
[47] Hr. Tr. August 14, 2025, pp. 76:25-77:12.

by the supplemental supply resources with a well-documented and strategic priority to consider the critiques to the current approach in capacity planning for any future proceedings.