Decision No. R25-0316-I

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 24M-0493G

IN THE MATTER OF THE COMMISSION'S INVESTIGATION INTO THE COSTS OF PUBLIC SERVICE COMPANY OF COLORADO'S GAS UTILITY INFRASTRUCTURE PURSUANT TO SENATE BILL 23-291.

INTERIM DECISION ORDERING FILING OF INFORMATION BY PUBLIC SERVICE COMPANY OF COLORADO

Issued Date: April 23, 2025

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I. STATEMENT

1. The Commission opened this Proceeding on November 14, 2024, through Decision No. C24-0824 to identify and investigate the cost causation of residential development and other development of Public Service Company of Colorado's ("Public Service" or the "Company") gas utility operations pursuant to § 40-3-121, C.R.S. The Decision also designated Commissioner Megan M. Gilman as Hearing Commissioner pursuant to § 40-6-101(2), C.R.S.

2. The Hearing Commissioner set forth a Proceeding work plan including proceeding objectives and a workflow of activities through Interim Recommended Decision No. R24-0937-I issued on February 27, 2025.

3. This Decision requires Public Service to file information discussed below, no later than May 27, 2025 and June 9, 2025, respectively, to be used in the Commission's cost causation investigation of residential development and other development.

A. Background

4. Decision No. C24-0824 opened this Proceeding pursuant to § 40-3-121, C.R.S. Section 40-3-121, C.R.S., requires the Commission to identify and study specific, new large infrastructure investments. For each investment identified, the Commission must determine the extent to which new residential development or other development by a geographic area disproportionately necessitated the investment. The proceeding must also include a cost benefit analysis of the growth in new residential development and other development to the natural gas utility customers for whom the investments were made, as well as non-participating natural gas utility customers and income qualified customers. The Commission must also determine whether alternative infrastructure, service investments, or other utility actions could mitigate impacts on non-participating or income-qualified customers and identify the up-front and service life costs and benefits of alternatives to new large infrastructure projects.

5. Interim Recommended Decision No. R24-0937-I established the work plan of the Proceeding in an effort to increase transparency for the public, stakeholders, and the Company of the anticipated timing and general methodology of the Commission's study. The work plan includes a comment period on the work plan, plans for data compilation (addressed by this Decision), a technical workshop, publication of a report and associated comment period, and a

hearing pursuant to § 40-3-121, C.R.S. Through Decision No. R24-0937-I comments were solicited from stakeholders regarding Proceeding objectives and parameters for project selection.

6. Public Service and the Colorado Office of the Utility Consumer Advocate ("UCA") filed comments on the work plan in response to Interim Recommended Decision No. R24-0937-I on March 14, 2025.

7. In Public Service's comments, it addresses the proposed work plan and suggests a slightly delayed timeline to accommodate the fact that most of its staff who will be working to prepare for the data request and technical conference are also preparing the Company's 2025 Gas Infrastructure Plan filing to be filed in May.[1]

8. Regarding project selection, Public Service comments that it supports centering the discussion upon historical and actual costs as opposed to forecasted costs, but suggests that only projects presented in the most recent rate case ("Proceeding No. 24AL-0049G" or the "2024 Gas Rate Case") should be utilized.[2] The Company asserts that the data will be more readily available for these projects and that changes to the line extension policy in recent years would affect the comparison of projects. In UCA's responsive comments, it agrees with Decision No. R24-0937-I that projects presented in the two most recent gas rate cases and their actual costs should be utilized for this investigation.[3]

9. The Company also suggests that it "may not be representative to focus the evaluation on infrastructure investments that are among the largest infrastructure investments categorized as discrete New Business or Capacity Expansion" as contemplated by Decision No. R24-0937-I. The Company requests further clarity on how many projects the Commission

[1] Public Service Responsive Comments, p. 4.
[2] Public Service Responsive Comments, p. 7.
[3] UCA Responsive Comments, p. 1.

anticipates considering, and requests that the list for consideration be provided shortly after the data request order since it may not be feasible to provide the information for all projects.[4]

10. Regarding the other working definitions provided in Decision No. R24-0937-I, the Company states that in its perspective inter-related projects are those that are intended to mitigate the same risk, not necessarily geographically related.[5] UCA supports the proposed parameter to consider "interrelated or geographically grouped investments as a single project" but believes that taking an approach in which a project is in a single town or county as too restrictive. UCA requests a more expansive and flexible approach of "geographic areas" for the purpose of the Commission's investigation in this Proceeding.[6] Regarding "non-participating customers" the Company argues that the discussion in Decision No. R24-0937-I is overly restrictive and a concept more similar to the GIP Rules, particularly Rule 4553(c)(I)(K), would be better suited for this analysis. Finally, regarding the cost-benefit analysis proposals in Decision No. R24-0937-I, the Company cautions against using the CBA handbook which is meant to look on a going-forward basis and instead consider something more similar to a financial-based calculation, such as the revenue vs. revenue requirement approach employed in the 2024 Gas Rate Case.[7]

11. UCA also provides comments regarding the "inextricable linkage" it sees between this Proceeding and the Mountain Energy Project (Proceeding No. 25A-0044EG). UCA points to several Senate Bill ("SB") 23-291 statutory requirements which require a similar analysis here to what will occur in Proceeding No. 25A-0044EG. UCA views the purpose of this Proceeding as paving the way for the Commission's approach to Public Service's proposed natural gas

[4] Public Service Responsive Comments, pp. 7-8.
[5] Public Service Responsive Comments, p. 9.
[6] UCA Responsive Comments, p. 2.
[7] Public Service Responsive Comments, pp. 12-13.

infrastructure projects which is also relevant in assessing Public Service's Mountain Energy Application.[8]

B. Discussion, Findings, and Conclusions

1. Responsive Comments to Decision No. R24-0937-I

12. The Hearing Commissioner acknowledges some of the difficulties inherent in reviewing granular project-specific data from years past as pointed out by Public Service and agrees with the Company that collaboration between the Hearing Commissioner and the Company will be crucial in ensuring that the Commission can meet its statutory obligations pursuant to SB 23-291. While this Decision does not offer an updated Workplan Timeline, the Company's proposed modifications to the Proceeding timeline will be taken into consideration, while also considering our statutory obligation to complete this work.

13. The Hearing Commissioner also appreciates the thoughtful comments from the Company and UCA on the parameters for project selection and working definitions provided in Decision No. R24-0937-I. Specifically, the Company's comments that inter-related projects should be defined by risk relation classification provides a helpful view of appropriate ways to group inter-related projects. However, the Hearing Commissioner highlights that SB 23-291 requires that that the Commission take "geographic area" into consideration as a part of the study.[9] As a result, this Proceeding may take multiple approaches that could include aspects like the risk profile and the geographic co-location of an infrastructure investment into consideration in evaluation of a project's cost causation. As a follow up to the Company's suggestion, the

[8] UCA Responsive Comments, p. 4.
[9] Section 40-3-121(1)(b), C.R.S.

Commission seeks information on the risk profiles of infrastructure investments as a part of this Decision and plans to discuss the risk profiles of projects as a part of a technical conference.

14. The Hearing Commissioner also appreciates UCA highlighting the linkage between the analysis in this Proceeding and the Company's Mountain Energy Application pending before the Commission. The Hearing Commissioner agrees and sees similar overlap between the analyses in both Proceedings and anticipates that the ongoing discussions in that proceeding may color the methodology used here. However, the Hearing Commissioner acknowledges upfront that each project is unique and requires an independent analysis, and most importantly, that the adjudication of the Mountain Energy Application must proceed on its own record.

2. Identification of Consultant and Procedural Considerations

15. The Commission determines that it is necessary to engage a consultant to facilitate its review and completion of the investigation in this Proceeding. To that end, the Commission has engaged the services of Aspen Environmental Group ("AEG") pursuant to § 40-2-104, C.R.S.[10] Pursuant to the Commission's Practice and Procedure Rules, "Commission staff" means individuals employed by the Commission, including individuals appointed or hired by the Director pursuant to § 40-2-104, C.R.S. The Hearing Commissioner anticipates that the AEG team will work closely with the Company to ensure that the Commission can properly effectuate the requirements in SB 23-291.

16. Commission Rule 1100(i) ensures that Commission staff shall have access as necessary to confidential and highly confidential information if the non-disclosure agreement requirements of Rule 1100(i) are met. Rule 1100(i) requires the signing of an annual NDA by

[10] Section 40-2-104(4)(a), C.R.S., allows for the Commission to contract with outside consultants and experts as necessary to carry out its functions. AEG is designated as Commission staff only for the purposes of this Proceeding.

Commission staff. So that they may engage with any confidential and highly confidential information possessed by the Commission necessary to help with the investigation in this Proceeding, the members of the AEG team expected to be directly engaged on this project will provide standard executed non-disclosure agreements which meet the requirements of both Rule 1100(i) and 1101(i), to be uploaded to the E-filing docket for this Proceeding and provided to the Company's counsel.[11]

17. AEG is expected to assist the Commission with several steps of the Workplan discussed in Decision No. R25-0138-I, including reviewing and evaluating data, preparing for and participating in the technical conference, and drafting the final report.

3. Data Request Directives

18. As indicated by Decision No. R25-0138-I, the Commission needs certain data and other system information from the Company to complete the requirements set out in § 40-3-121, C.R.S. To that end, the Company shall provide the following data, by project, in an executable form:

a. For Discrete New Business Projects described in line numbers one (1) through seven (7), sixteen (16), seventeen (17) and line twenty-three (23) of Hearing Exhibit 105, Attachment ARG-4, submitted in Proceeding No. 24AL-0049G; the four (4) projects described in Hearing Exhibit 106, Attachment JHZ-9 submitted in Proceeding No. 22AL-0046G; and line numbers 32 and 42 of Hearing Exhibit 106, Attachment JHZ-10, submitted in Proceeding No. 22AL-0046G:

   i. For residential projects: provide the number of new residential units the infrastructure investment intended to serve, including, individually, the number of homes, townhomes, and apartments served and their respective average square footages. Provide the anticipated peak demand and annual usage expectations per residential unit type and the source of the assumption used for planning the project. Provide the observed actual peak demand and annual usage data associated with residential projects on both an average and aggregate basis for the new residential units within the project area.

[11] Pursuant to Commission Rule 1101(i), no party or "authorized agent of a party" shall have access to information filed under seal until it signs a nondisclosure agreement consistent with the Commission's Rules.

ii. For commercial projects: provide the combined square footage of commercial units the project intended to serve. Provide the anticipated peak demand and annual usage expectations per commercial unit or per commercial square foot and the source of the assumption used for planning the project. Provide the observed actual peak demand and annual usage data associated with commercial projects on both an average per square foot and aggregate basis for the new commercial units within the project area.

iii. Design day peak hour demand: provide the planned design day peak demand of the project in mscf.

iv. Average day load: provide the planned annual average daily gas load served by the project in Mcf.

v. Annual addition to revenue requirement: provide the annual dollar amount this project added to the Company's revenue requirement

vi. Amortization period: provide the number of years over which the project will be amortized by project components.

vii. Annual operations and maintenance: provide an estimate of annual operations and maintenance costs associated with this project and its components for the duration of its estimated useful time in service.

viii. Estimated annual revenue excluding supply: provide the planned annual additional revenue the project will generate for the Company, excluding commodity costs on both an annual usage and per customer basis.

ix. Customer requesting the project: indicate whether the request for new service served an individual or a developer.

x. Identify upstream connecting line and change in its spare line capacity: identity the upstream connecting line from the project and provide the spare line capacity of the connecting line before construction and after construction of the project. Please narratively identify any upstream capacity constrained areas. Identify any upgrades to the upstream components for capacity or reliability purposes completed in the five (5) years prior to the new business work.

xi. Non-pipeline Alternative ("NPA") evaluated: Indicate whether or not the Company conducted a non-pipelines alternative analysis for the project. If yes, please provide the analysis and any supporting workbooks or documents.

xii. Hydraulic analysis results showing impact of new load: describe the scope and key assumptions of the hydraulic analysis conducted in association with this new project. Give the line numbers, the upstream interconnect or system segment, identify the nearest regulator station, the model criterion used to establish an expansion was needed, the value of that model criterion (*e.g.*, operating pressure) with and without the expansion. Identify what pressure threshold caused the Company to conclude new facilities were needed and by what timeframe. Indicate if the hydraulic analysis demonstrated any impacts upstream of the project and describe them. Describe all scenarios analyzed. Provide a written justification of the hydraulic analysis showing the impact of new load which necessitated project development, including any risks of over- or under-pressurization.

xiii. Could the technical requirements of the load have be served solely with electricity or is dual fuel required? Provide a written justification of whether the project could be served solely by electricity or whether dual fuel is required.

xiv. Conferred with electric utility on adequate capacity to serve: did the Company confer with the local electric distribution company(ies) on whether there was adequate electric capacity to serve the customer if they fully electrified? If so, identify the local electric distribution company and indicate their response.

xv. Disproportionately impacted community analysis: Did the project provide new service for customers in a disproportionately impacted community? If so, how many customers of disproportionately impacted communities did the Company estimate that the project would serve?

xvi. Ancillary benefits: provide an estimate of ancillary benefits the Company evaluated as a part of its decision to construct the project. Describe the methodology by which the company derived these estimates. Provide the following data for each project:

1. Lower energy bill
2. Home amenity
3. Quantified benefits to other customers in form of lower rates
4. Customer preference
5. Home builder preference
6. Lower cost of new home

xvii. Ancillary costs: provide an estimate of ancillary costs the Company evaluated as a part of its decision to construct the project. Describe the methodology by which the company derived these estimates. Provide the following data for each project:

1. Revenue requirement of new business project, including negative net salvage value

2. Unrealized upstream costs (including negative net salvage value of upstream gas infrastructure)
3. Administrative costs

xviii. Cost of Service/Rates Model: provide a copy of the Company's cost of service and rates model used when planning these projects, preferably in Excel with formulas intact. Please identify and explain how the 2022 and 2024 rate case projects changed the revenue requirement in each case. Is the expected amortization and depreciation for each of these projects the same? If not, please provide for each.

xix. Indicate if there are additional interrelated discreate new business or capacity projects that address a common risk to this project. If so, describe the interrelated project(s) and indicate the line item(s) that reflect(s) work orders meant to address the common risk shared with this project.

xx. Costs and benefits of alternatives: provide the costs and benefits of potential alternatives feasible at the time, including beneficial electrification, demand response, alternative infrastructure, and other utility actions.[12] For each cost and benefit requested, provide a dollar value. Please align the alternative costs and benefit categories as closely as possible with the EMTRC categories defined in the Company's Cost Benefit Analysis Handbook, with the modifications identified in Recommended Decision R25-0083 issued in Proceeding No. 24M-0261G, using the following cost and benefit categories:

1. New equipment cost: electric appliances (list the appliances and their assumed cost); any electrical panel upgrade; and any electricity distribution line upgrade
2. Existing equipment replacement cost, appropriately discounting based on average age of existing equipment in homes located in the area of the project
3. Administrative costs, considering expected change in costs over time as the Company gains experience with the NPA implementation.
4. Marginal generation capacity cost from peak hour demand gas reduction converted to electricity use accounting for a diversity of equipment operating at the peak hour (electric resistance backup and heat pumps) and load controllability in the peak hour. The NPA electricity use incorporated into this cost should only consider demand in excess of what is already needed for Company electrification plans and should be based on Xcel Encompass modeling and the most recent available price information and should consider the timing of this expense.

[12] Section 40-3-121(2) C.R.S. requires the Commission to identify alternatives to the infrastructure investments made by the Company and evaluate the costs and benefits of identified alternatives.

5. Marginal transmission capacity cost from peak hour demand gas reduction converted to electricity use accounting for a diversity of equipment operating at the peak hour (electric resistance backup and heat pumps) and load controllability in the peak hour. Costs should also consider the location of the NPA, equipment capacity temperature impacts depending on whether the peak hour is in the summer or winter, timing of this expense, and to what extent the NPA electricity demand necessitates transmission needs in excess of what is already planned by the Company in other proceedings.
6. Marginal distribution capacity cost from winter peak hour demand gas reduction converted to electricity use accounting for a diversity of equipment operating at the peak hour (electric resistance backup and heat pumps) and load controllability in the peak hour. Costs should also consider the location of the NPA, equipment capacity temperature impacts depending on whether the peak hour is in the summer or winter, timing of this expense, and to what extent the NPA electricity demand necessitates distribution needs in excess of what is already planned by the Company in other proceedings.
7. Ancillary service cost from peak hour demand gas reduction converted to electricity use accounting for a diversity of equipment operating at the peak hour (electric resistance backup and heat pumps) and load controllability in the peak hour.
8. Energy cost
9. Incremental line losses cost
10. Incremental generation long-run marginal emissions cost
11. Incremental generation methane leakage cost, considering the generation mix in hours of additional electric load
12. Winter mitigation cost (if applicable)
13. Incremental gas infrastructure cost (if applicable)
14. Federal, state, local, and other utility incentive benefits
15. Avoided gas commodity benefits accounting for avoided leakage
16. Avoided electric commodity benefits (*e.g.*, from improved efficiency of summer heat pump operation vs air conditioning in the summer)
17. Avoided methane leakage benefit
18. Avoided CO2 benefit, considering the combustion efficiency of a range of housing age and building code in the area of the NPA
19. Indoor air pollution reduction benefits

b. For Discrete Capacity Expansion Projects described in line numbers one (1) through four (4), seven (7), nine (9), 18, and 20 of Hearing Exhibit 105, Attachment ARG-6, submitted in Proceeding No. 24AL-0049G and line number five (5) of Hearing Exhibit 106 Attachment JHZ-5 submitted in Proceeding No. 22AL-0046G, provide:

   i. Residential units: provide the number of firm residential customers (or equivalents), separately: a. downstream of the identified project at the time the project was completed; b. added downstream of the identified project in the five (5) years prior to the time the project was completed; and c. at risk of an outage that necessitated the project and their aggregate peak day load.

   ii. Commercial units: provide the number of firm commercial customers (or equivalents) at risk of an outage that necessitated the project. Provide the square footage and aggregate peak day load of these customers.

   iii. Design day projected shortfall; provide the design day projected shortfall in Dth/day if the project was not completed.

   iv. Quantified outage risk percentage: provide the quantified outage risk percentage used to conduct the needs analysis for the project.

   v. Expected average daily throughput: provide the average daily throughput of the existing line prior to the capacity expansion project as well as the expected average daily throughput after construction.

   vi. Other benefits: provide a list of other benefits the Company evaluated as a part of its decision to construct the project. For each other benefit evaluated, provide a dollar value ascribed to that benefit.

   vii. Indicate if there are inter-related discrete new business or capacity projects completed within five (5) years of completion of this project addressing a common risk as this project. If so, describe the interrelated project and indicate the line item that reflects the work orders meant to address the common risk shared with this project.

   viii. Please indicate if any new business project was built downstream of this capacity expansion project in the last five years and identify that new business project, including its projected and actual loads on both an average and peak day basis.

   ix. Please provide, for each year back to 2020:

      1. The average day and peak day capacity that the Company holds on individual upstream interstate pipelines and the associated interconnection locations;

      2. Whether the Company held any discussions with any upstream interstate pipeline about subscribing to additional (a) firm capacity; (b) interruptible capacity; and (c) storage capacity, and if so, specify by how much for each category; and

3. The sum of all Company physical interconnection capacity with interstate pipelines.

x. Please provide, for each year back to 2020 for each of the Company's 12 Service Areas:[13]

1. The average day and peak day capacity that the Company holds on individual upstream interstate pipelines within the Service Area and the associated interconnection locations; and

2. Whether the Company held any discussions with any upstream interstate pipeline about subscribing to additional (a) firm capacity; (b) interruptible capacity; or (c) storage capacity within each Service Territory, and if so, specify by how much for each category.

xi. Actual throughput of completed projects: provide the observed peak throughput of the project in Dth/day for each full heating season the project was in service.

xii. Costs and benefits of alternatives: please provide information on potential alternatives to the capacity expansion project feasible at the time, including beneficial electrification, demand response, alternative infrastructure, and other utility actions using the same cost and benefit categories as the new business project alternatives described in paragraph 18(a)(xx) above.

19. The Hearing Commissioner is cognizant of the multiple ongoing proceedings that require support from the same team members from Public Service and the inherent complexity of the data request outlined in Paragraph 18 of this Decision. As a result, the Hearing Commissioner will set differing deadlines for some aspects of the data request with the goal of facilitating delivery of groups of information in as timely a manner as possible:

a. The Company shall provide data unrelated to the costs and benefits of alternatives to a project (defined in paragraph 18(a)(i)-(xix) and paragraph 18(b)(i)-(xi) of this Decision) by May 27, 2025. This aligns with the Company's suggestion in its reply to the Workplan Order to allow five weeks to provide data and comports with the Commission's anticipated receipt of the gas infrastructure plan filing in May 2025.

b. Recognizing the challenges with conducting a cost-benefit analysis for hypothetical alternatives to a project outlined in paragraphs 18(a)(xx) and 18(b)(xii) of this Decision, the Hearing Commissioner requires that the Company first provide a portfolio of non-pipeline alternatives, alternative infrastructure, service

[13] In "Public Service Company of Colorado's Supplemental Response to Commission Questions Posed in Decision No. C23-0566-I" filed September 22, 2023, in Proceeding No. 23M-0234G, the Company provided a map "that displays a state-wide view of the Company's twelve separate natural gas systems," at 15.

investments, or other utility actions for each project identified in paragraph 18(a) and paragraph 18(b) of this Decision to the Commission by June 9, 2025.

c. Upon review and approval of the alternative portfolios to be evaluated for each project by the Hearing Commissioner, by future decision, the Company should expect to be requested to submit the data required by paragraph 18(a)(xx) and paragraph 18(b)(xii) of this Decision.

20. The Company shall also provide written comments no later than May 27, 2025, indicating what type of review of it expects is possible with respect to the technical conference to be scheduled in this Proceeding.[14] Please indicate through written comments to what extent historical system condition data is available, including the ability to view and test assumptions of the hydraulic models used to identify system constraints for which the infrastructure investments encompassed in this study were planned to address, so that a future decision can better describe the process and requirements of the planned technical conference.

II. ORDER

A. It Is Ordered That:

1. Public Service Company of Colorado shall provide:

a. The information outlined in above paragraph 19(a) no later than May 27, 2025;

b. The information outlined in above paragraph 19(b) no later than June 9, 2025.

c. The information outlined in above paragraph 20 no later than May 27, 2025.

[14] Decision No. R25-0138-I indicated that a technical conference would likely include Company gas system modelers, and representatives from stakeholders as appropriate. The workshop will likely provide the Commission and stakeholders an opportunity to ask questions clarifying system conditions that the Company evaluated when determining the need for infrastructure investments as well as the Company's projections for whom the new infrastructure investments would serve.

2. This Decision is effective immediately upon its Issued Date.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

MEGAN M. GILMAN

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Hearing Commissioner