Decision No. C24-0956-I

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 24A-0442E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2024 JUST TRANSITION SOLICITATION.

INTERIM DECISION ESTABLISHING REQUIREMENTS FOR SUPPLEMENTAL DIRECT TESTIMONY

Issued Date: December 31, 2024
Adopted Date: November 20, 2024 & December 18, 2024

TABLE OF CONTENTS

I. BY THE COMMISSION

A. Statement

1. On October 15, 2024, Public Service Company of Colorado ("Public Service" or the "Company") filed a Verified Application of Public Service Company of Colorado for Approval of its 2024 Just Transition Solicitation ("Application").

2. At the November 20, 2024 Commissioners' Weekly Meeting ("CWM"), the Commission conducted an initial discussion of potential topics for supplemental direct testimony ("SDT") that it would require Public Service to develop and submit. At that CWM, the Commission decided not to make any final determinations about SDT, choosing instead to further consider the record, invite party input on SDT topics, and to take up the matter again at a later date.[1]

3. By this Decision, considering the responses including from the Company, the Commission establishes the topics for the Company to address through supplemental direct testimony. As discussed below, the Commission confirms nine topic areas initially discussed at the November 20, 2024 CWM; includes three additional limited areas, specifically with regard to wholesale market and transmission considerations; and provides directives on specific directions

[1] Decision No. C24-0872-I, issued November 22, 2024.

from prior orders that were not yet included. Given the Company's representations, and consistent with Decision No. C24-0941-I addressing procedural matters, we require the Company file SDT filings on or before January 31, 2024.

B. SDT Topics Initially Considered at the November 20, 2024 CWM

4. As discussed below, we confirm nine directives from SDT topics initially discussed on November 20, 2024.[2]

1. Lower Load Growth Scenario

5. At the November 20, 2024 CWM, Chairman Blank suggested requiring the Company to model a load growth scenario significantly below the Base Case and Low load growth scenarios the Company presented in its direct testimony. Chair Blank suggested that this scenario would assume load growth consistent with the base case load growth scenario from the Company's 2021 Electric Resource Plan ("ERP") Proceeding,[3] and specified sales growing at a cumulative average growth rate ("CAGR") of 1.11 percent from 2024 through 2032, sales growth of 1.33 percent from 2024 through 2050, and peak load growth averaging 0.8 percent from 2024 through 2050. The Chair suggested that the Company be required to develop a full capacity expansion plan and dispatch based on these growth rates and to specify the differences by sector in sales and peak between this lower growth scenario and the Base Case for large new loads, electric vehicles and building electrification.

6. In its Response to Decision No. C24-0872-I ("Response"), the Company states it would need to create a new sales and demand forecast, new portfolio and generation modeling, new transmission analysis, and a new rate forecast. In order to make this more comparable to

[2] The Commission initially discussed, but declines to further require, specific procurement questions regarding DR and VPPs in SDT.

[3] Proceeding No. 21A-0141E.

existing scenarios, the Company suggests that this scenario should be based on changing the inputs to the Company's forecasts rather than attempting to pin forecast outputs to certain annual growth rates. The Company recommends making the following assumptions: (1) retail growth remains the same as its base case and low scenarios; (2) eliminate all incremental beneficial electrification ("BE"); (3) eliminate data center and manufacturing load growth beyond what is already approved; and (4) no further electrification of oil and gas operations.[4]

7. While we appreciate Public Service's initial response to the lower-low load forecast, we decline to adopt the Company's proposed inputs. We would also point out that Rule 3606(b) requires Public Service to provide three separate forecasts – a high, base, and low load growth forecast – which the Company declined to do here, providing only two forecasts. The purpose of the lower-load forecast request is to have the Company present a realistic view of the impacts on load, resource need, and rates if load growth were to continue at more historical growth rates, consistent with the assumptions used in the 2021 ERP. Adopting the Company's proposal to maintain the retail growth rates assumed in the Company's base and low scenarios but assume no incremental beneficial electrification growth would not accomplish this purpose and does not seem like a reasonably defensible alternative.

8. Thus, we direct the Company to develop a lower-low forecast with the following assumptions. First, the retail sales and peak demand growth shall be based on historical experience from 2010-2023 as presented in the 2021 ERP[5] and in this Proceeding.[6] In addition, the Company shall assume growth rates in beneficial electrification and transportation electrification consistent with what was assumed in the 2021 ERP. Likewise, the growth rate in the electrification of oil and

[4] Public Service Response at pp. 5-6.
[5] Proceeding No. 21A-0141E, Hr. Ex. 101, Attachment AKJ-2_Technical Appendix, Rev. 2, pp. 33, 35.
[6] Hr. Ex. 101, Attachment JWI-2, Volume 2, pp. 30, 32.

gas operations shall be consistent with the growth rate assumptions in the 2021 ERP. Generally aligned with the Company's proposed approach regarding data center and manufacturing load growth, we would require the Company to include only those individual new loads that have either already been approved by this Commission or have fully executed energy service agreements prior to the mailed date of this order.

2. Rate Impact Modeling

9. Chair Blank's second recommendation for SDT at the November 20, 2024 CWM included that the Company conduct rate impact modeling using the "lower low" scenario in the same format as the models already provided by the Company. This analysis would differentiate between the cost per kWh on large new loads such as QTS Aurora Infrastructure, LLC's data center[7] and all other ratepayers across all three demand growth scenarios, and assume that all new large loads receive the same rate treatments as QTS. Chair Blank further recommended asking the Company to provide metrics in terms of the new retail revenues required for each of the three categories (large loads, electric vehicles, and beneficial electrification) presented in Figure 2.2-5 on p. 44 of the Technical Appendix[8] that would allow the Commission to collectively understand what load growth in each individual category was needed to meet the rate impact targets on line 64 of the rate impact model under all scenarios.[9]

10. In its Response, Public Service states that it does not expect to provide a discounted rate to new large loads or data centers for the foreseeable future, so modeling accounting for impact of discounts is unnecessary.[10]

[7] *See* Proceeding No. 23A-0330E.
[8] Hr. Ex. 101, Att. JWI-2, Volume 2.
[9] These models are presented in Hr. Ex. 101, Attachments JWI-5 and JWI-6.
[10] Public Service Response at p. 6.

11. While the Company states it does not intend to provide a discounted rate to new large load or data centers in the foreseeable future, the example of QTS Aurora Infrastructure, LLC is the only one currently available to us and we continue to view this information in SDT as useful. We prefer, however, that as much information as possible be publicly available, and are concerned that using actual rates such as those approved in Proceeding No. 23A-0330E may require the resulting modeling to be confidential. In order to ensure that the rate impact analysis remains publicly available, we direct the Company to conduct the analysis using two assumptions: one in which all new large loads receive a discount of 17.5 percent, and the other in which new large loads receive no discount.

3. Expanding the RFP to Include Distribution-Connected Battery Energy Storage Bids

12. Chair Blank also suggested SDT to expand the Phase II RFP, related model contract, and other documents to solicit dispatchable distribution-connected battery energy storage ("BES") bids that can interconnect to the distribution system including at the high voltage side of distribution substations. Chair Blank emphasized that the goal with this request is to cast light onto how such resources could reduce the substantial transmission and distribution investment the Company anticipates needing.[11] Chair Blank specified that (1) the model contract should include a liquidated damages term to ensure that these resources perform when needed, (2) that payment structures be similar or identical to those for transmission-connected BES systems, (3) that the model contract should also include terms giving Public Service similar dispatch control and flexibility as it has for utility-scale BES, (4) that the Company be allowed to bid Company-owned BES as well; and (5) that the model contract be structured as an in-front of

[11] Hr. Ex. 101 (Attachment JWI-2), pp. 111-13.

the meter arrangement like transmission-interconnected BES. Commissioners Gilman and Plant expressed support for this proposal.

13. In Response, Public Service notes that while virtual power plants ("VPPs") have benefits, they are not very helpful for extended periods of low renewables output. The Company states that it is not aware of modeling capabilities that can link VPPs, localized distribution or transmission benefits and capacity reductions in the context of the modelling it conducts to support the ERP. The Company notes that its modeling platform, EnCompass, does not reflect material differences between storage connected on either side of the meter, but that the Company does believe that the resource benefits of distribution-sited storage may be stackable with local, distribution-sited benefits. However, it notes that there is currently no accepted methodology to credit locational distribution benefits to storage and opines that it would be difficult to develop such a methodology within this proceeding. As a result, the Company states that it could solicit distribution connected storage in Phase II, but the results might not price in the full benefits of these resources.[12]

14. In their responses to Decision No. C24-0872-I, UCA, the Coalition for Community Solar Access ("CCSA") and Colorado Communities for Climate Action ("CC4CA") all expressed an interest in SDT regarding the potential for distribution connected storage to offset transmission and distribution investment. To create a record enabling acquisition of dispatchable distributed generation, CCSA calls for an extensive modeling effort to be conducted as SDT.[13]

15. We acknowledge the current absence of a methodology to assess the locational value that generating assets can provide in offsetting or delaying otherwise needed distribution and

[12] *Id*. at pp. 6-7.
[13] UCA Proposals for Supplemental Direct Testimony at p. 8; CCSA Response at pp. 1-5; CC4CA Response at p. 4.

transmission investments, and hope to investigate this issue in the Company's Distribution System Plan proceeding and perhaps the forthcoming Denver Metro Certificate of Public Convenience and Necessity ("CPCN") application proceeding. This discussion highlights a potential weakness of the modeling in that it is unclear in how it values capacity added in the distribution system, as discussed in remaining requests for SDT and may be of significant concern as this Commission considers potentially enormous new distribution and transmission system investments in other contexts. Nevertheless, we continue to believe that, to the extent reasonably feasible, we should be considering generation, transmission, and distribution benefits and costs in siting new BES systems and seeking to put these systems in constrained locations.[14] We also note that § 40-2-130.5(2)(c)(II), C.R.S., directs the Commission to establish a methodology to assess this locational value. Despite the fact that the Company's current methodology may undervalue distribution-connected storage, we nonetheless direct the Company to expand the JTS all-source RFP document[15] and add an RFP and model contract to Appendix D10 to solicit BES bids that can interconnect to the distribution system through new greenfield development or by adding new BES to rooftop solar or CSGs.[16]

4. Disclosure of Other Locational Advantages and Disadvantages

16. At the November 20, 2024 CWM, Commissioner Gilman expressed concern about the fairness of the bidding process in the Company's last ERP proceeding and the need for all bidders to have a common understanding of any and all location-related advantages or disadvantages. Commissioner Gilman proposed requiring the Company to disclose any other

[14] As discussed in Decision No. C24-0941-I, we further require conferral through January 17, 2025, that includes potential inclusions of both the Distribution System Plan proceeding and anticipated Denver Metro CPCN application proceeding.

[15] Hr. Ex. 101, Att. JWI-3.

[16] We do not, however, pursue expansion at this time of the JTS to include modeling of DR and VPP load in this context through SDT.

location-related needs or system benefits, including any specifics on resource locations, generation types, reliability impacts, transmission or distribution costs or other preferences that the Company expects to express as part of its Phase II resource evaluation. Both Chair Blank and Commissioner Plant expressed support for this SDT, emphasizing that such information must be disclosed in Phase I of this Proceeding.

17. No parties provided substantive discussion or recommendations on this issue in their responses to Decision No. C24-0872-I.

18. Accordingly, we direct the Company to file as SDT narrative descriptions of any and all location-related advantages or disadvantages that could influence bid selection in Phase II of this proceeding. In addition to the factors listed above, we direct the Company to address whether variations in the availability of gas supply are likely to result in independent power producer ("IPP") gas-fired generation bids in certain areas being disfavored or eliminated from consideration due to inadequate gas supply, and if so, how and when bidders will learn of this possibility.

5. Detail impact of Electrification on Forecasts

19. At the November 20, 2024 CWM, Commissioner Gilman proposed requiring Public Service to provide detail to elucidate the relationship between the load growth due to the Company's most recent Transportation Electrification, Clean Heat, and DSM/BE plans[17] and the energy and peak load forecasts presented in this Proceeding, to ensure consistency between proceedings. Chair Blank and Commissioner Plant both expressed strong support for this proposal. None of the parties provided substantive comments on this proposal.

[17] Proceeding Nos. 23A-0242E, 23A-0392EG, and 23A-0589EG.

20. Accordingly, we direct Public Service to provide SDT identifying the contribution to annual energy sales and summer and winter peak load attributed to the plans cited above for the Company's forecasts and to separately identify any additional load growth contributions attributable to transportation electrification and beneficial electrification incremental to the levels approved in those plans.

6. Impact of Declining Retail Gas Sales on Gas-Fired Generators

21. At the November 20, 2024 CWM, Commissioner Gilman proposed requiring the Company to present modeling of the impact of future reduction in retail gas sales on cost allocation to gas-fired generation, and how this might impact the modeled or actual production costs of such generators over time. Both Chair Blank and Commissioner Plant supported this proposal.

22. Public Service states that modeling of this impact is complex and uncertain. It notes that future throughput is subject to individual customer decisions, and that the impact on rates is also highly uncertain given that the Commission will need to address impacts of declining usage in future rate cases. The Company opined that the current rate structure is not likely to be continued as consumption drops. It also noted that it will likely continue to transport gas for other local distribution companies that also have uncertain forecasts. The Company further commented that gas generation units using the Company's system may switch their gas supply to federally regulated interstate pipelines instead, which could mitigate the impact on electric customers. The Company states that it respectfully requests the Commission not order it to conduct any specific modeling, which it claims would create false precision. Company states that it is willing to address in SDT the Commission's questions on these topics, including the ability to perform a sensitivity using full tariff price on Colorado interstate gas as a proxy.[18]

[18] Public Service Response at pp. 8-9.

23. We appreciate Public Service listing various uncertainties regarding gas supply costs. While the Company argues that attempting to model future changes would create false precision, we note that assuming that no changes occur also results in false precision. The Commission directs Public Service to provide input in its SDT on the feasibility of setting in Phase I an annual firm gas supply cost escalator and using this cost escalator to run a sensitivity. The purpose of such a sensitivity would be to better understand potential cost impacts of gas service given potential future changes in the market that could impact cost allocation to gas generators. Public Service shall also discuss whether bidders should be asked to provide information regarding the cost to receive gas from an interstate pipeline instead of the Company's system and the associated cost differential with such an option both initially and over time.

7. Avoiding Future Contracting Delays

24. At the November 20, 2024 CWM, Commissioner Gilman proposed requiring the Company to provide a narrative describing actions that the Company has or plans to take to avoid the Phase II review delays and contracting delays that contributed to the resource adequacy concerns and cost overruns on resources selected as part of the approved portfolio through the 2021 ERP proceeding. This is particularly concerning given that the reasoning for many delays in the prior ERP was the number of bids, yet given the identified resource need, it is possible that the JTS will continue to see a high number of bids, which must be considered and dealt with in a timely manner. Chair Blank and Commissioner Plant both expressed strong support for this proposal.

25. None of the parties provided substantive comments on this proposal.

26. Accordingly, we direct the Company to provide its response to this question in its SDT.

8. Impact of Aggregated Distributed Energy Resources or Virtual Power Plants on Needed Gas-Fired Capacity

27. Commissioner Plant noted that in the JTS portfolios that model 900 MW of aggregated distributed energy resources, the Company indicates that there would be no impact on the gas-fired capacity selected in capacity expansion planning. Commissioner Plant proposed requiring the Company to submit SDT explaining why the Company's modeling had this counter-intuitive result. Both Chair Blank and Commissioner Gilman expressed support for this proposal.

28. Accordingly, we direct the Company to provide its response to this question in its SDT.

9. Distribution Capacity Procurement as a Means of Offsetting Transmission Capacity

29. At the November 20, 2024 CWM, Commissioner Plant proposed requiring the Company to submit SDT discussing opportunities for distribution system capacity investment to promote maximum load factor efficiencies on the distribution system that would offset the need for incremental investment in transmission capacity. Commissioner Plant noted that in a recent Settlement Agreement, Xcel's operating company in Minnesota committed to distribution capacity procurement for this purpose.[19]

30. Both Chair Blank and Commissioner Gilman expressed support for this proposal. Again, there were no substantive party comments on it. Accordingly, we direct the Company to provide its response to this question in its SDT.

[19] Xcel Energy's Joint Settlement Agreement filed in Docket No. E-002/RP-24-67 (MN PUC). As of the date of this Decision, the Minnesota PUC has not yet approved Xcel's proposed Joint Settlement Agreement.

C. Additional SDT Topics Discussed at the December 18, 2024 CWM

31. Eight parties filed recommendations for SDT in response to the Commission's invitation in Decision No. C24-0872-I. In its response, Public Service requested that the Commission limit additional SDT requests from intervenors, stating that these are better addressed in the discovery process and that such requests could delay this proceeding. While some party recommendations are supportive of the SDT concepts the Commission discussed at the November 20, 2024 CWM and there are some intriguing new concepts, we agree with the Company that the majority of the SDT requested by the parties would be properly posed as discovery questions and need not be required as SDT. The Commission does, however, require SDT on three additional topics.

1. Impact of Joining an Organized Wholesale Market

32. Subsection (2)(a) of § 40-5-108, C.R.S., requires that Public Service join an organized wholesale market ("OWM") by January 1, 2030 unless the Commission has determined that (1) no viable and available OWM exists on that date or (2) joining an OWM is not in the public interest. We note that January 1, 2030 falls one year into the three-year Resource Acquisition Period in this Proceeding, but that there is no discussion of participation in an OWM in the Company's direct testimony.

33. For the purposes of this Proceeding, we find it reasonable to assume that the Company will join an OWM no later than the beginning of 2030, and that doing so may have profound impacts on its resource acquisition and daily operations. While we recognize that it is difficult to specify such impacts with precision, we find it essential that these impacts be addressed in at least a qualitative manner. Accordingly, we direct Public Service to provide in SDT a narrative discussing the likely impacts of OWM participation on unit commitment and dispatch, reserve

sharing, effective load carrying capacity values, and the portfolios likely to emerge from optimized resource expansion planning. Additionally, this narrative should distinguish between the impacts of participation in a day-ahead market and an OWM that is, by statutory definition, a Regional Transmission Organization or Independent System Operator market.

2. Potential Impact of Dynamic Line Rating

34. In its response to Decision No. C24-0872-I, UCA recommends requiring SDT on the additional wind generation that could be accommodated on existing transmission lines if they were retrofitted with dynamic line rating ("DLR") equipment. We agree that DLR technology is potentially cost effective on transmission lines carrying significant amounts of power from wind generators. Accordingly, we direct the Company to report on the additional wind generation injection that could be enabled through DLR and the cost of implementing this technology on relevant transmission lines.

3. Modeling of Additional Transmission Connections

35. In addition to the above SDT, we direct the Company to conduct an alternative capacity expansion and dispatch optimization run to evaluate the benefits and costs of two potential new transmission lines. The first of these is the Three Corners Connector, a proposed 1.8 GW high-voltage direct current ("HVDC") transmission line running between the Comanche substation near Pueblo and the Guymon substation in Oklahoma (in the Eastern Interconnection), which is currently under development by a third-party developer.[20] For the purposes of this modeling, Public Service should assume that the project will be a joint rate base effort between Public Service and Southwest Public Service, with costs allocated consistent with the benefits to each utility service area.

[20] Grid United, *Three Corners Connector*, https://threecornersconnector.com/.

36. We would also require this modeling assume a new five-mile 345 kV line connecting the Lamar and May Valley substations as identified in the Colorado Electric Transmission Authority's recent Transmission Expansion Study.[21] For clarity, we expect that the modeling conducted will be a single joint study assuming both of these lines will be built, and that this will require a revised capacity expansion analysis.[22] The overall approach to benefits and cost allocation for these additional transmission connections should generally be consistent with the requirements in FERC Order 1920-A.[23]

D. Due Date for Supplemental Testimony on Distributed Generation Cost-Effectiveness

37. In direct testimony, Public Service states that it is developing model runs focused on Renewable Energy Standard program areas, pursuant to the Commission's finding in Decision No. C22-0678 that Rule 3615(a)(III) requires that any future program that cumulatively exceeds $30 million or 30 MW must be approved in an ERP proceeding.[24] The Company indicates that due to the press of business it was unable to complete these modeling runs prior to filing its application in this Proceeding, but that it will be filing supplemental testimony with these modeling results.

38. In its response to Decision No. C24-00872-I, the Clean Energy Industry ("CEI") opposed the admission of these modeling results into the record of this Proceeding, but requested that if the Commission were to determine that this information is required in this Proceeding, that

[21] Colorado Electric Transmission Authority, *Transmission Capacity Expansion Study for Colorado* (Dec. 2024), available at https://www.cotransmissionauthority.com/transmission-study.

[22] Implicit in this directive for a revised capacity expansion analysis, Public Service will need to evaluate and report on the new values of effective load carrying capability for each resource type as well as the new planning reserve margin value that would result from these lines being built.

[23] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920-A, FERC Docket No. RM21-17 (Nov. 21, 2024).

[24] Hr. Ex. 101, Direct Testimony of Jack Ihle, pp. 101-103.

it should direct the Company to file its supplemental testimony with sufficient time for intervenors to review and investigate this issue prior to the deadline for answer testimony.[25]

39. We agree with CEI that, if the Company expects it to be considered in the context of this Proceeding, this additional testimony must be submitted sufficiently in advance of the due date for answer testimony that parties will have the opportunity to effectively consider it, issue discovery and develop answer testimony. Accordingly, to the extent the Company plans to file additional modeling results related to distributed generation, we direct the Company to file this supplemental testimony no later than January 31, 2025.[26]

E. Unaddressed Directives from Proceeding No. 21A-0141E

40. There are three directives from Proceeding No. 21A-0141E that are not adequately addressed in the Company's direct testimony in this Proceeding. The first of these concerns aspects of the modeling conducted to develop the Company's planning reserve margin. In Paragraph No. 88 of Decision No. C22-0559, the Commission directed the Company not to limit modeled off-system purchases solely to its immediate neighbors and its historical purchases unless it could demonstrate that these modeling choices were consistent with best practice. In the same paragraph, the Commission directed the Company to respond to arguments the Conservation Coalition had raised about over-reliance on the reserve margin as a measure of reliability and the use of cost-benefit analysis to evaluate whether a 1-day-in-10-years loss of load expectation is optimal. While the Company's direct testimony addresses the practices of several other utilities, we are unable to locate testimony that is responsive to these directives.

[25] Clean Energy Industry Response at pp. 13-15.
[26] *See also* Decision No. C24-0941-I, ¶60.

41. The second area of unaddressed directives regards the discounting of the social cost of emissions ("SCE"). In Paragraph No. 302 of Decision No. C24-0052, the Commission directed the Company to confer with stakeholders and attempt to reach consensus on the issue of whether and how the SCE should be discounted. We have found no evidence in the Company's filing that it conducted the required stakeholder consultation, nor did we find any discussion of the Conservation Coalition's contention that a discount rate is already embedded in the SCE.

42. The final area regards the Commission's directive in Paragraph No. 182 of Decision No. C24-0161 for the Company to "explain its position" on Conservation Coalition's request to prohibit any reliability methodologies or metrics in Phase II of this Proceeding that were not approved in Phase I. While the Company has filed an explicit reliability rubric in its direct testimony, it has not explicitly "explained its position" on the use of any other methodologies or metrics in Phase II of this Proceeding.

43. Accordingly, we direct the Company to file responsive testimony to each of these three directives no later than the due date for SDT established by this Decision.

F. Co-Locating New Load and Generation in Just Transition Communities

44. We note the recently published report by Energy Innovation on co-locating new load and generation for the overall benefit of the system.[27] We also note that the Company has proposed bonus incentives for new generation located within transition communities and has indicated that it will facilitate discussions with just transition communities to site large new loads in those communities. However, the Company may have failed to adequately evaluate the benefits when new generation and new load are located together as outlined in the Energy Innovation

[27] Eric Gimon et al., *Energy Parks: A New Strategy to Meet Rising Electricity Demand* (Dec. 2024), available at https://energyinnovation.org/report/energy-parks-a-new-strategy-to-meet-rising-electricity-demand/.

report. We flag this issue as an area of interest for the forthcoming Denver Metro CPCN proceeding and note that we will be requiring the Company to quantify the benefit of adding load outside of the Denver Metro constraint.

II. ORDER

A. It Is Ordered That:

1. Public Service Company of Colorado shall file supplemental direct testimony consistent with the above discussion no later than Friday, January 31, 2025.

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

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING November 20, 2024 & December 18, 2024.

(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