Decision No. C24-0161

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A-0141E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN.

COMMISSION DECISION ADDRESSING APPLICATIONS FOR REHEARING, REARGUMENT, OR RECONSIDERATION OF COMMISSION DECISION NO. C24-0052

Mailed Date: March 13, 2024
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I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Commission addresses the Applications for Rehearing, Reargument, or Reconsideration of Decision No. C24-0052 (RRR or RRR Applications) filed on February 12, 2024, by Public Service Company of Colorado (Public Service or Company), Staff of the Colorado Public Utilities Commission (Staff), Utility Consumer Advocates (UCA), the Colorado Energy Office (CEO), Colorado Solar and Storage Association and Solar Energy Industries Association (jointly COSSA/SEIA), Western Resource Advocates (WRA), and the

Natural Resources Defense Counsil and Sierra Club (collectively, the Conservation Coalition). Consistent with the discussion below, we grant, in part, and deny in part, the RRR Applications from Public Service, Staff, CEO, COSSA/SEIA, WRA, and the Conservation Coalition. We deny UCA's RRR Application.

2. Also through this Decision, the Commission grants the Motion for Leave to File a Response (Motion to Respond) filed by Public Service on February 26, 2024.

B. Background

3. As discussed in Decision No. C24-0052, issued January 23, 2024, (the Phase II Decision), Public Service initiated this Proceeding on March 31, 2021, by filing an application for approval of its 2021 electric resource plan (ERP) and clean energy plan (CEP). In accordance with § 40-2-125.5(4), C.R.S., the Company's CEP aims to reduce the Company's carbon dioxide (CO_2) emissions by a target of 80 percent by 2030 as compared to 2005 levels and seeks to provide customers with energy generated from 100 percent clean energy by 2050. As set out in Decision No. C22-0459 (Phase I Decision)[1] and Decision No. C22-0559 (addressing RRR to the Phase I Decision)[2] the Commission approved certain elements of the Company's CEP, including the Coal Action Plan that provides for early retirement and conversion of the Company's remaining coal facilities.

4. Though Phase II of this Proceeding the Commission authorized Public Service to further implement the requirements for approval of a CEP such that the Commission could continue evaluation of, among other things, the additional CEP activities, the actions and investments projected to achieve compliance with the clean energy targets in § 40-2-125.5(3)(a)(I)

[1] Issued August 3, 2022.
[2] Issued September 21, 2022.

and (3)(a)(II), and whether the CEP is in the public interest and consistent with the clean energy target in n § 40-2-125.5(3)(a)(I). The Commission's decisions in Phase I and Phase II of this Proceeding thus balance years of litigation, including thousands of pages in filings, to implement bold energy policies that transition Colorado towards a clean, renewable energy future.

5. Throughout Phase II of this Proceeding, Public Service showcased its Preferred Portfolio of resources as well as an Updated Preferred Portfolio of resources (or the UPP). The Company's Preferred Portfolio and the UPP were both projected to exceed statutory requirements for emissions reductions. Certain comments received from intervenors in this Proceeding, however, argued that the Phase II modeling overstates emissions reductions from the UPP and understates the ultimate costs that customers would pay.[3]

6. After considering comments from intervenors, as well as members of the public, and multiple deliberations on the significant record on January 23, 2024, the Commission issued its Phase II Decision in which it found that modifying the proposed CEP to include an alternative resource portfolio is necessary to ensure the CEP is in the public interest. The Phase II Decision explains that, not only is the Alternative Portfolio expected to exceed statutory requirements for emissions reductions, the Alternative Portfolio is supported by other statutory and public interest findings, including costs to ratepayers, reliability, future technology development, and transmission concerns.[4]

7. In addition to the resource portfolio, the Phase II Decision also gives directives to Public Service regarding things like the process for selecting backup bids, performance incentive

[3] *See, e.g.*, Phase II Decision, ¶¶ 84-89 (discussing party concerns, including regarding the Company's Preferred Portfolio).

[4] Phase II Decision, ¶¶ 90-144.

mechanisms (PIMs), future transmission investments, and future ERP proceedings, including the 2024 Just Transition Solicitation (JTS).

8. On February 12, 2024, the following parties filed RRR Applications: Public Service, Staff, UCA, CEO, COSSA/SEIA, WRA, and Conservation Coalition. In general, the RRRs seek clarifications to the Phase II Decision or request modifications to certain established processes, like the process for selecting backup bids or the calculations for the PIMs. Conservation Coalition was the only party that requests the Commission select a different portfolio of resources.

9. On February 26, 2024, Public Service filed a Motion for Leave to Respond and Response (Motion to Respond). Public Service states that it seeks to lodge a "targeted response" to allegations COSSA/SEIA makes in its RRR.

10. Since the Phase II Decision issued, the Commission has continued to receive comments from members of the public. Numerous comments urge the Commission to prohibit the construction of new natural gas plants for reasons such as climate change and air pollution. The Commission also received comments supporting the construction of a new transmission segment known as the May Valley Longhorn Extension (MVLE). Lamar City Council, the Board of County Commissioners of Prowers County, and Prowers Economic Prosperity all submitted comments in this regard.

C. Conservation Coalition Request on Resource Portfolio

11. Conservation Coalition spends the vast majority of its RRR Application urging the Commission to select a different resource portfolio. Specifically, instead of the Alternative Portfolio, Conservation Coalition asks that the Commission select the Inverse 1324 Portfolio or, in the alternative, the Least-Cost Portfolio or the Lower Dispatchable Portfolio. All of the portfolios that Conservation Coalition advances were constructed using the social cost of carbon

(or SCC) in the capacity expansion phase of modeling. In contrast, the Alternative Portfolio is a 0CO_2$ portfolio in that the SCC was not used in the capacity expansion phase of modeling.

12. Conservation Coalition sets forth numerous arguments supporting its position that the Alternative Portfolio the Commission selected is inferior to the Inverse 1324 Portfolio, the Least-Cost Portfolio, and the Lower Dispatchable Portfolio according to the five factors the Commission considers in the Phase II Decision: emission reductions, reasonable cost to customers, reliability, future technology development, and transmission concerns. More generally, Conservation Coalition argues that the Commission should not move forward with the Alternative Portfolio because it is a 0CO_2$ portfolio as opposed to an SCC portfolio.

13. Conservation Coalition's arguments present flawed logic and fail to recognize many complexities and nuances considered and addressed by the Commission's Phase II order in modifying the CEP by selecting the Alternative Portfolio.

1. Emissions Reductions

14. In its Phase II Decision, the Commission acknowledged that there were other portfolios that—at least as modeled—achieved greater emissions reductions.[5] While Conservation Coalition argues that there is no evidence supporting the conclusion that the cumulative emissions increase in the Alternative Portfolio is "slight" as opposed to "significant," the Colorado Department of Public Health and Environment's Phase II CEP Verification Report calculates that the Alternative Portfolio will have emissions reductions of 86 percent.[6] The Inverse 1324 Portfolio meanwhile will have emissions reductions of 87 percent.[7] The Alternative Portfolio and the Inverse 1324 Portfolio are likewise comparable when looking at the total Present Value Societal Cost (PVSC), which accounts for the net present value (NPV) of both SCC and the social cost of methane (SCM). The Alternative Portfolio has a PVSC of $50,858 million.[8] The Inverse 1324 Portfolio has PVSC of $50,236 million—a decrease of approximately 1.2 percent.[9]

15. Turning to curtailments, one of the primary motivations for the Commission's selection of the Alternative Portfolio was the fact that, as modeled, it is projected to have approximately one-third the renewable energy curtailment volume projected for the UPP. The Commission found that it "is reasonable to assume that curtailments that the model fails to capture will follow similar trajectories."[10] In other words, portfolios with high levels of modeled curtailments will likely have more actual curtailments compared to portfolios with lower levels of modeled curtailments, and the unmodeled curtailments (the differential between actual

[5] Phase II Decision, ¶¶ 97-98.
[6] CDPHE Phase II CEP Verification, pp. 4-5.
[7] CDPHE Phase II CEP Verification, pp. 4-5.
[8] 120-Day Report (Appendix S) Rev. 1, p. 26.
[9] 120-Day Report (Appendix S) Rev. 1, p. 3.
[10] Phase II Decision, ¶ 106.

curtailments and modeled curtailments) will result in costs and emissions that are not shown in the Phase II modeling.

16. Conservation Coalition argues the Commission's logic is flawed because there is no evidence that the relative difference between each portfolio will change. We disagree. In the 120-Day Report, Public Service explains that "the model primarily captures what is called 'bottoming' curtailments, *i.e.*, curtailment associated with excess generation above the hourly load obligation."[11] The Company goes on to note that "a large percentage of curtailment is the result of real time perturbations in the system that are not captured in the model, such as transmission line outages and orders from the transmission system operator … to solve local congestion or reliability events."[12] The Company also explains that substantial increases in the amount of weather dependent generation can be expected to increase curtailments, but that curtailments are expected to be maintained at manageable levels due to the large amount of existing and planned storage.[13] This evidence supports the conclusion that portfolios that rely on the delivery of large amounts of weather dependent generation will have more unmodeled curtailments relative to portfolios that replace some of the weather dependent generation with storage resources. Compared to the Alternative Portfolio, the Inverse 1324 Portfolio has 550 MW more solar and 1,706 MW more wind for a total of 2,256 MW more weather dependent generation. The Alternative Portfolio primarily replaces this 2,256 MW of weather dependent generation with an additional 678 MW of storage. If there is a transmission line outage or local transmission congestion, the portfolio that relies on the delivery of vast quantities of new generation will experience more unmodeled

[11] 120-Day Report, p. 95.
[12] 120-Day Report, p. 95.
[13] 120-Day Report, p. 95. Public Service goes on to argue that the model obtained the optimal economic balance of additional renewable generation and curtailments. As discussed in the Phase II Decision, however, the model does not optimize for the curtailments caused by transmission congestion or perturbations in the system. (Phase II Decision, ¶ 97).

curtailments compared to portfolios that have more dispatchable storage resources and fewer new generation resources.

17. The Commission's analysis of the evidence on this issue parallels the analysis that Staff provides in its Phase II Comments. For instance, Staff states that the high levels of curtailment that are likely to result from the Preferred Portfolio due to the combination of early development of generation resources, lower storage capacity, and later transmission in service dates (ISDs), are not accounted for in the NPV revenue requirement (NPVRR) and curtailment costs are likely to be significantly lower for the \$0CO_2 portfolios.[14] Staff states that the level and costs of curtailments in the Phase II modelling cannot be trusted, particularly regarding the Preferred Portfolio "and all other portfolios that add similar amounts of wind and solar."[15] Staff notes, however, that the higher levels of storage and lower amounts of modeled curtailments in \$0CO_2 portfolios suggest that these portfolios will have fewer unmodeled curtailments. In addition to the normal transmission line outages and congestion that cause unmodeled curtailments, Staff predicts that there will be "[v]ery high levels of curtailment" until the transmission network upgrade projects are complete and that while construction of the network upgrades is on-going there will also be very high levels of curtailment. Staff states that the lower level of renewable generation in the \$0CO_2 portfolios will likely result in fewer unmodeled curtailments from the transmission upgrade projects "as compared to the preferred plan and the other SCC portfolios."[16]

18. Turning more specifically to the transmission upgrade projects, Conservation Coalition criticizes as erroneous the Commission's assessment that most of the new renewable

[14] Staff's Comments, p. 50.
[15] Staff's Comments, p. 32.
[16] Staff's Comments, p. 32.

generation would be in service prior to the construction of the majority of the associated transmission upgrades. Conservation Coalition's analysis on this point focuses nonsensically on the simple *number* of projects completed. In essence, the Conservation Coalition's argument assumes that each of the 25 transmission network upgrade projects that Public Service lists in Appendix Q to the 120-Day Report will result in equal improvements to the transmission system such that as soon as the first 13 projects are completed, "the majority of the associated transmission investments" will be in place. Under this line of reasoning, the $1.7 million Greenwood Substation Bus Tie Uprate is equally able to deliver new generation as the $1.4 billion New Double Circuit 230 kV line from Harvest Mile-Chambers-Sandown-Cherokee.[17] While this simplistic view allows Conservation Coalition to dismiss the risk of high levels of unmodeled curtailments and their associated costs and emissions, the number of upgrade projects completed in a given year is an extremely poor barometer of the degree of incremental power deliverability provided.

19. In contrast, Staff's analysis of the 120-Day Report and the 25 transmission network upgrade projects listed in Appendix Q to the 120-Day Report remains compelling. Staff reiterates that in the 120-Day Report Public Service acknowledges that "all of the transmission required cannot reasonably be deployed within the same timeframe as the generation resources in the Preferred Plan" and the Company will maintain reliability by using tools such as curtailments.[18] Analyzing the 25 specific network upgrade projects, Staff notes that eight of the projects have ISDs after 2028 and that these eight projects represent over 85 percent of the estimated $2.3 billion dollars in transmission network upgrades.[19] Staff goes on to observe:

[17] *See* 120-Day Report (Appendix Q), pp. 32, 34.
[18] Staff's Comments, p. 43 (quoting 120-Day Report, p. 134).
[19] Staff's Comments, p. 43.

> [T]he Company provides … no explanation of how it will deliver energy from the generation portfolio when the transmission the Company identifies as necessary will not be on-line until years after the generation projects…. [I]f the Company can't deliver the power, it raises the question as to whether the generation project[s] should be brought on line as early as 2026 to 2028 if the power cannot be delivered and ratepayers are on the hook to pay for resulting curtailed energy.[20]

20. Moreover, the Phase II modeling assumes that Public Service will be able to complete all of this substantial transmission work on time. This too is doubtful. As Public Service explains in Appendix Q to its 120-Day Report: "Based on recent experience with transmission development, the Company anticipates risk to on-time completion of these projects because of the size and complexity of the transmission portfolio; construction sequencing and scheduling; local siting challenges and permitting timelines; … and labor constraints from competing projects."[21] The Company goes on to note that "project delays are likely to impact system dispatch and operations, resulting in increased curtailments until the full transmission portfolio can be completed."[22]

21. In sum, we are unpersuaded by Conservation Coalition's arguments regarding emissions reductions, transmission investments, and curtailments. The Phase II Decision correctly finds that while the UPP arguably provides greater emissions reductions than the Alternative Portfolio, the accuracy of these emissions reductions is questionable due to unmodeled curtailments and the expectation that the majority of the associated transmission upgrades will not be constructed until 2030. This analysis remains true when comparing the Alternative Portfolio to the portfolios that Conservation Coalition now advances in its RRR Application: the Inverse 1324 Portfolio, the Least-Cost Portfolio, and the Lower Dispatchable Portfolio. The Phase II modeling

[20] Staff's Comments, p. 44.
[21] 120-Day Report (Appendix Q), p. 21.
[22] 120-Day Report (Appendix Q), p. 21.

predicts the Alternative Portfolio will have 1,629 GWh of curtailments in 2028.[23] In contrast, the Inverse 1324 Portfolio has 5,558 GWh of curtailments in 2028, the Least-Cost Portfolio has 5,595 GWh of curtailments in 2028, and the Lower Dispatchable Portfolio has 6,091 GWh of curtailments in 2028.[24] Like the Inverse 1324 Portfolio, the Least-Cost Portfolio and Lower Dispatchable Portfolio have much higher levels of renewable generation and much lower levels of storage compared to the Alternative Portfolio. Thus, like the UPP, the evidence supports the conclusion that Conservation Coalition's preferred portfolios will have much higher levels of unmodeled curtailments than the Alternative Portfolio.

2. Reasonable Costs

22. We also are unpersuaded by Conservation Coalition's arguments regarding reasonable costs. The Phase II Decision observes that the Alternative Portfolio is less expensive than the UPP on a NPV basis.[25] The Phase II Decision cites the likely costs of unmodeled curtailments as further supporting the Alternative Portfolio.[26] Likewise, the Commission raises potential costs associated with Company-owned gas generation assets "including construction and operational cost overruns, decommissioning costs, and the potential that the gas resources will become stranded" as supporting the Alternative Portfolio (which has 200 MW fewer Company-owned gas resources).[27] Finally, the Commission states that a larger portfolio like the UPP eliminates opportunities to take advantage of future technology developments, including through a more robust use of demand side resources.[28]

[23] 120-Day Report (Appendix T), p. 23.
[24] 120-Day Report (Appendix T), pp. 3, 4, 6.
[25] Phase II Decision, ¶ 103.
[26] Phase II Decision, pp. 39-40.
[27] Phase II Decision, ¶ 108.
[28] Phase II Decision, ¶ 109.

23. Conservation Coalition's position that the Alternative Portfolio is more expensive than some of its preferred portfolios relies on a simplistic view of when transmission investments will be available to deliver power from new generation resources and the resulting impact of unmodeled curtailments. Because the model only considers bottoming curtailments and not curtailments relating to things like transmission line outages or local congestion, the NPV and emissions numbers that Conservation Coalition cites fail to include the likely substantial cost impact of unmodeled curtailments.

24. Putting aside the significant issue of unmodeled curtailments, Conservation Coalition is correct that the Phase II modeling estimates that the NPV of the Alternative Portfolio will be $86 million higher than the Inverse 1324 Portfolio and this number increases to $622 million when the social costs of emissions are included. However, these numbers must be viewed in context of the total estimated price of the various portfolios. Both the Alternative Portfolio and the Inverse 1324 Portfolio have a total present value revenue requirement (PVRR) of over $44 billion and a PVSC (which accounts for the social costs of emissions) of over $50 billion.[29] Again, these numbers assume—despite the record evidence to the contrary—that the Alternative Portfolio and the Inverse 1324 Portfolio will have the same amounts of unmodeled curtailments.

25. We likewise find Conservation Coalition's argument about Company-owned gas resources unavailing. The Phase II Decision raises several costs of Company-owned gas resources that do not appear in the Phase II modeling PVRR calculations, "including construction and operational cost overruns, decommissioning costs, and the potential that the gas resources will

[29] The Alternative Portfolio's PVRR is $44,285 million after accounting for the $288 million NPV increase that, according to Public Service's statements in Response Comments, would appear in virtually all portfolios. (Phase II Decision, ¶ 103). The Inverse 1324 Portfolio's PVRR is $44,199 million after accounting for the additional $288 million. (120-Day Report (Appendix S) Rev. 1, p. 3).

become stranded."[30] Conservation Coalition seems to summarily dismiss potential cost overruns that ratepayers might pay for Company-owned assets because these have "nothing to do with stranded assets."[31] This ignores the fact that ratepayers have traditionally faced significantly more risk of shouldering cost overruns for Company-owned projects compared to cost overruns for Independent Power Producers (IPP) projects.[32] The considerable effort the Commission has made in this Proceeding regarding PIMs does not eliminate this risk.

26. Regardless, the withdrawal of Bid 0235 largely moots this issue. At this time, it is unclear whether the gas assets under Conservation Coalition's preferred Inverse 1324 Portfolio will move forward as Public Service proposes in its RRR Application or whether one or more of the other gas resources (such as Bid 0510, Bid 0514, or Bid 1061)—all of which are existing, short-term Power Purchase Agreement (PPA) resources—will be used to replace Bid 0235.

27. Conservation Coalition additionally asserts that the Commission speculates about the availability of future technology in a way that is unlawful and bad policy. However, the Phase II Decision states that "acquiring a smaller portfolio of resources in this Proceeding creates more optionality in future proceedings for efficiencies and cost savings, including through a more robust use of demand side resources."[33] It is neither bad policy nor unlawful to expect that in the 2024 JTS the Commission will continue to improve efficiencies and find new ways to better incorporate demand side resources.

28. Finally, Conservation Coalition repeats numerous times throughout its RRR Application the argument that the Alternative Portfolio is more expensive on a dollar-per-MW

[30] Phase II Decision, ¶ 108.
[31] Conservation Coalition's RRR, p. 16.
[32] *See* Phase II Decision, ¶ 180.
[33] Phase II Decision, ¶ 109.

basis and that by selecting a larger portfolio like the Inverse 1324 Portfolio the Commission could be acquiring incremental generating resources at no incremental cost. This argument is meritless. To begin, despite its advocacy in Phase I regarding the appropriate effective load carrying capability (ELCC) for storage resources, Conservation Coalition's argument in RRR fails to acknowledge the difference between nameplate capacity and accredited capacity. The Inverse 1324 Portfolio has approximately 1,500 MW additional *nameplate* capacity as the Alternative Portfolio but has relatively similar amounts of accredited capacity.[34] Throughout this Proceeding, no party has suggested that 100 percent of the nameplate capacity of wind and solar resources can count towards reliably serving customer load, yet this is the rationale underlying Conservation Coalition's simplistic dollars-per-MW metric. Conservation Coalition treats unaccredited, nameplate capacity from wind and solar resources as equal to the nameplate capacity of dispatchable resources such as storage and gas. This is an unacceptable approach to resource planning.[35] As the Commission explains in the Phase II Decision, a 300 MW solar facility will be of no value to meeting customer load once the sun sets, but a 300 MW solar plus storage facility can be expected to continue contributing to the electrical system. Simply put, the addition of storage can contribute value in ways that are not reflected in the amount of nameplate capacity.[36]

3. Reliability

29. Regarding reliability, Conservation Coalition notes that Public Service has endorsed the Inverse 1324 Portfolio as reliable. Conservation Coalition thus argues that the Inverse 1324 Portfolio is just as reliable as the Alternative Portfolio.[37] In the alternative,

[34] 120-Day Report (Appendix S) Rev. 1, pp. 3, 26. The Alternative Portfolio has 1,562 MW of accredited capacity and the Inverse 1324 Portfolio has 1,613 MW of accredited capacity.
[35] *See generally*, HE 114 (Scholl Direct), pp. 12-22.
[36] Phase II Decision, ¶ 111, fn. 125.
[37] Conservation Coalition's RRR, pp. 20-21.

Conservation Coalition argues that the Commission should approve the Least-Cost Portfolio or the Lower Dispatchable Portfolio. Conservation Coalition acknowledges reliability concerns from Public Service regarding these portfolios but nonetheless asserts that the Least-Cost Portfolio and the Lower Dispatchable Portfolio meet all of the reliability metrics the Commission approved in Phase I.[38]

30. We take no issue with the argument that the Inverse 1324 Portfolio is generally just as reliable as the Alternative Portfolio. However, the same is not true for the Least-Cost Portfolio. To begin, Public Service has raised reliability concerns with both of these portfolios. The Least Cost Portfolio does not include the strategically located gas resources the Company asserts are necessary for transmission support.[39] We remain disappointed that the Company did not clearly communicate in Phase I the specific, locational reliability concerns underpinning the strategically located gas resources, but SB 19-236 prohibits the Commission from approving a plan that does not protect system reliability.[40] The Company has similarly raised concerns with the Lower Dispatchable Portfolio's use of Bid 1061.[41]

31. Even assuming that there was sufficient record evidence for the Commission to conclude that the Company's concerns regarding reliability are unwarranted, the Least-Cost Portfolio and the Lower Dispatchable Portfolio suffer the same flaws as the Inverse 1324 Portfolio. For example, the Least-Cost Portfolio's NPVRR is only $13 million lower than the Alternative Portfolio's NPVRR, while the Lower Dispatchable Portfolio is actually $195 million more expensive than the Alternative Portfolio.[42] These costs fail to include, however, the costs

[38] Conservation Coalition's RRR, p. 21.
[39] Public Service's Response Comments, p. 29.
[40] Phase II Decision, ¶¶ 124-25.
[41] Phase II Decision, ¶ 127.
[42] Conservation Coalition's RRR, p. 8.

associated with unmodeled curtailments. The modeling's projected emissions reductions likewise assume that there will be no unmodeled curtailments. As with the Inverse 1324 Portfolio, the evidence supports the conclusion that there will be substantially more unmodeled curtailments in the Least-Cost Portfolio and the Lower Dispatchable Portfolio compared to the Alternative Portfolio.

4. Future Technology

32. In the Phase II Decision, the Commission found that a smaller, less aggressive resource acquisition consistent with the Alternative Portfolio provides additional time for the Commission to better understand and take advantage of developing technologies to reduce costs.[43] The Phase II Decision lists distribution management and new demand response programs as examples of quickly advancing technologies.[44] The Phase II Decision further notes the large amounts of storage in the Alternative Portfolio marks the first step in a new approach to resource planning for a modern, cost-effective grid that avoids simply building increasing amounts of generation that results in high curtailments and high costs.[45]

33. Conservation Coalition's arguments focus on the deferral of roughly 1,500 MW of nameplate renewable generation capacity and the fact that the 2024 JTS is just months away to assert that future technology developments are unrealistic. However, these arguments fail to acknowledge that the Alternative Portfolio acquires relatively similar amounts of accredited capacity compared to the Inverse 1324 Portfolio. Contrary to Conservation Coalition's suggestions, the Alternative Portfolio does not simply eliminate renewable generation capacity. Rather, it replaces this generation capacity primarily with 678 MW of additional storage capacity.[46]

[43] Phase II Decision, ¶ 132.
[44] Phase II Decision, ¶ 137.
[45] Phase II Decision, ¶¶ 131, 137.
[46] Phase II Decision, ¶ 92.

This dispatchable storage capacity, which will remain on the system long past the 2024 JTS, could prove instrumental in allowing the Commission to incorporate more advanced demand side resources and distribution management technologies in future ERPs that are filed several years from now. In short, the Commission is not relying on ground-breaking technological developments to suddenly appear in time for the 2024 JTS. The additional storage resources in the Alternative Portfolio will create optionality well past the year 2030.

34. In addition, as noted above, the expectation that the Commission will continue to advance quickly developing technologies such as demand side resources beginning with the 2024 JTS is not speculative. This is especially so given the shortcomings of the Phase II modeling in this Proceeding. For instance, in the Phase I Decision the Commission directed Public Service to model a demand response (DR) sensitivity to show how higher amounts of DR influence resource selection. Although more DR in a portfolio would seemingly reduce the need for additional capacity additions, the DR sensitivity actually resulted in more resource acquisitions compared to the Preferred Portfolio.[47] Staff analyzed this anomaly and states that the modeling constraints that Public Service imposed in Phase II prevented additional amounts of DR from reducing the amount of capacity additions. Per Staff's Phase II Comments: "Staff concludes that additional DR could have a significant impact on capacity needs but the overly-constrained Preferred Plan made the Commission-ordered DR sensitivity ineffective."[48] Improving the Phase II modeling to better reflect the impact of increasing amounts of DR is an obvious example of how the Commission could better evaluate replacing supply-side resources with additional amounts of DR in the 2024 JTS.

[47] 120-Day Report, pp. 109-10.
[48] Staff's Comments, p. 35.

35. As the Phase II Decision notes, Staff is not the only party that raised issues with how Public Service conducted the Phase II modeling. In its Phase II Comments, Conservation Coalition lambasts Public Service's Phase II modeling, asserting that the Company's modeling violates the Phase I Settlement and the Commission's Phase I order.[49] At one point, Conservation Coalition states: "Given the serious problems with the Company's modeling that are described above, if this case had not already been delayed both in Phase I and II, we would strongly recommend that the Commission not approve any resources until the Company to reruns [*sic*] its modeling and the parties can litigate the new modeling methods the Company adopted in Phase II."[50] Conservation Coalition goes on to state, however, that it does not wish to delay approval of renewable and battery storage bids and associated transmission projects.

36. In Phase I of the 2024 JTS, parties will have the opportunity to litigate Public Service's modeling methods, and in Phase II of the 2024 JTS, the Company will rerun its modeling. If anything, deferring the acquisition of additional generation resources until the 2024 JTS will give parties and the Commission more confidence that the underlying modeling is accurate.

5. SCC Portfolio versus 0CO_2$ Portfolio

37. Finally, we disagree with Conservation Coalition's argument that the Commission should select a different resource portfolio because the Alternative Portfolio is a 0CO_2$ portfolio. The five statutory and public interest factors discussed above support the Alternative Portfolio, including as compared to Conservation Coalition's preferred portfolios. The fact that the Alternative Portfolio is a 0CO_2$ portfolio does not alter this analysis.

[49] Conservation Coalition's Comments, p. 2.
[50] Conservation Coalition's Comments, p. 10.

38. To be clear, the Commission has considered (and continues to consider) the social cost of emissions in our resource planning decisions. As the Phase II Decision states:

> Throughout this Proceeding and in selecting the Alternative Portfolio, the Commission has considered the PVRR of both the social cost of carbon (SCC) and the social cost of methane (SCM), which also helps in our considerations on emission reductions…. For the capacity expansion phase of the modeling, the Alternative Portfolio does not include the social cost of emissions. Post-modeling, however, in the 120-Day Report the SCC and SCM associated with the Alternative Portfolio are both presented. Moreover, the Coal Action Plan, which is critical to emissions reductions, is hardwired into the Alternative Portfolio. While there are other portfolios that have still greater reductions in SCC and SCM, notwithstanding the uncertainties around curtailment impacts to those figures, the Alternative Portfolio exceeds the 80 percent emissions reductions set forth in the statute while balancing other factors such as costs, reliability, and future optionality.[51]

39. As for Conservation Coalition's specific concern regarding the amount of gas \$0CO_2 portfolios contain, as presented the Alternative Portfolio contains 41 MW more gas resources than the Inverse 1324 Portfolio. With the withdrawal of Bid 0235, however, this number will likely change. For instance, if the Commission approves the Company's preferred replacement bid for Bid 0235 (Bid 1000), the Alternative Portfolio would only have 22 MW more gas resources compared to the Inverse 1324 Portfolio. If one or more of the other gas resources (such as Bid 0510, Bid 0514, or Bid 1061) replace Bid 0235, the Alternative Portfolio could end up having less gas resources than the Inverse 1324 Portfolio that Conservation Coalition now advances.

40. Aside from the differing amounts of gas resources, the record shows several benefits to a smaller \$0CO_2 portfolio in this Proceeding.[52] These benefits, such as fewer unmodeled curtailments with their associated costs and emissions impacts, have been discussed as part of the Commission's analysis of the five statutory and public interest factors.

[51] Phase II Decision, ¶ 98 (footnotes omitted).
[52] *See, e.g.*, Staff's Comments, p. 50.

41. Regarding the purported inconsistency between approval of SCC dispatch and the Alternative Portfolio, we note that the Conservation Coalition fails to acknowledge the limits of the SCC dispatch. SCC dispatch was part of the Phase I Settlement, but the Phase I Settlement contemplates that Public Service will only use SCC dispatch "until [the Company] enters an organized market structure of any kind, including, without limitation, an energy imbalance market."[53] The Phase I Decision notes that the time period for SCC dispatch will be significantly shorter than anticipated if Public Service joins the Western Energy Imbalance Service market in April 2023, per the Company's announcement.[54]

42. For the sake of argument, even if Public Service is still using an SCC value in the dispatch or commitment of resources, this does not warrant modifying the selected portfolio. Any inconsistency does not impact the evaluation of the five factors discussed above.

43. In conclusion, we reiterate our finding that modifying the CEP to include the Alternative Portfolio is necessary to ensure the CEP is in the public interest. Admittedly, none of the portfolios presented in Phase II are perfect, but the record evidence, including evidence regarding unmodeled curtailments and the numerous benefits of additional amounts of storage, show that the Alternative Portfolio is superior to the UPP as well as the three portfolios Conservation Coalition advances in its RRR Application. Likewise, no model is perfect, and the modelling often seems as far more of an art than a science. The projected costs and emissions set forth in the Phase II modeling have documented shortcomings, and we have seen in other contexts how forecasted cost and performance estimates deviate significantly from the reality that ratepayers must fund. Deferring certain resource acquisitions, maintaining optionality, and

[53] Phase I Decision, ¶ 411 (quoting the Phase I Settlement Agreement, ¶ 36).
[54] Phase I Decision, ¶ 412.

continuing our evaluation of these issues in the forthcoming 2024 JTS is a prudent, common-sense approach of moving forward in an environment characterized by enormous uncertainty.

D. Bid 1029

1. Background and Summary

44. On October 25, 2023, the Commission heard a government-to-government comment from William Walksalong, the Tribal Administrator of the Northern Cheyenne Nation and a descendant of the Sand Creek Massacre. Mr. Walksalong described the atrocities committed by the U.S. Volunteer Cavalry against 230 Cheyenne and Arapaho villagers, including women, children, and the elderly. He also described the significance of the site to descendants of the Sand Creek Massacre, who visit to pay homage and have worked carefully to commemorate the victims and repatriate remains.

45. During his address to the Commission, Mr. Walksalong encouraged the Commission to pursue potential rules that would protect sacred sites like the Sand Creek Massacre National Historic Site. Stakeholder processes with the Northern Cheyenne Nation have been underway with an intent to bring forward a notice of proposed rulemaking in the coming weeks.

46. In its Phase II decision, the Commission acknowledged that Bid 1029 has strong economics and allowed the Company to include Bid 1029 in the Alternative Portfolio. The Commission agreed with Public Service and CEO and rejected a request by Staff to exclude Bid 1029 from the Alternative Portfolio. In so doing, the Commission explained that this "is in no way an approval of the project, which must necessarily be vetted through continued stakeholder and community considerations."[55] The Commission also suggested that Bid 1016 (another Company-owned wind bid) serve as a backup to bid 1029 and directed Public Service to continue

[55] Phase II Decision, ¶ 205.

the process of engaging with the Northern Cheyenne Nation and to bring back more specific information if the project moved forward in its follow-on application for a certificate of public convenience and necessity (CPCN).

47. In its RRR, Public Service states that it is currently engaging with the developer for Bid 1029 and with Tribal governments. However, it seeks an explicit finding from the Commission that, should the Commission grant a CPCN for the project with changes to address viewshed and cultural impact issues, the PIM applied to Bid 1029 may be adjusted to account for any corresponding impacts to projected operations and economics. [56] In addition, Public Service seeks a specific approval of Bid 1016 as the backup for Bid 1029.[57]

48. Staff asks the Commission to reduce the risk of future confusion by confirming whether it intended to exclude Bid 1029 from a presumption of prudence by its statement that including Bid 1029 in the Alternative Portfolio "is in no way an approval of the project," which must continue to be vetted. [58]

49. UCA requests the Commission reject Bid 1029 outright because of its impacts to the viewshed of the Sand Creek Massacre National Historic Site, arguing that protection of the site is in the public interest and raising questions regarding appropriate stakeholder engagement in this and follow-on proceedings. While many of the questions UCA raises seem to relate to potential interests of the Northern Cheyenne Nation regarding the Sand Creek Massacre National Historic Site, UCA does not include whether it conferred with the Tribal Nation in making its filing.[59] In addition to its impacts to the Sand Creek Massacre National Historic Site, UCA argues that Bid

[56] Public Service's RRR, pp. 5-6.
[57] Public Service's RRR, pp. 5-6.
[58] Staff's RRR, pp. 4-5.
[59] UCA's RRR, pp. 4-7.

1029 would also trigger the need for expensive upgrades to the Denver Metro transmission system.[60]

50. Instead of Bid 1029, UCA supports the alternatives to Bid 1029 that Staff set forth in its Phase II Comments.[61] UCA also recommends replacing Bid 1029 with Bid 1024, which UCA asserts is much less expensive than Bid 1016. UCA acknowledges that the Company already intends to use Bid 1024 to replace Bid 0045[62] (a 375 MW Company-owned wind project), making Bid 1024 unavailable as a replacement for Bid 1029. With little analysis, UCA states that the Commission should use Bid 0562 (a 252 MW wind PPA) to replace Bid 0045, thereby allowing Bid 1024 to replace Bid 1029.[63]

2. Findings and Conclusions

51. At the outset, we agree with UCA's statements in RRR that there is no place in Colorado "more deserving of reverence, remembrance, and preservation of sanctity."[64] Considering the record in this case, including ongoing consultation between the Company and the Northern Cheyenne Nation, we address RRR Applications to best enable the Company to pursue appropriate mitigation efforts, but also to encourage the Company to pivot to a backup bid

[60] UCA's RRR, pp. 8-9.

[61] UCA's RRR, p. 7 (citing Staff's Comments, pp. 55-79). For context, in its Phase II Comments Staff explains that it ran three test scenarios in which it removed Bid 1029 from the resource portfolio. In test scenario 1, Bid 1029 was replaced by a 200 MW solar PPA (Bid 375). In test scenario 2, Bid 1029 was removed and no replacement bid was selected. In test scenario 3, Bid 1029 was replaced with Bid 1024 (a 603 MW Company-owned wind bid). Staff notes, however, that it was unable to test the reliability of these test scenarios. (Staff's Comments, pp. 58-59).

[62] Public Service confirmed in its RRR Application that Bid 0045 (and its variant Bid 0043) has failed and needs to be replaced with Bid 1024. (Public Service's RRR, p. 24; Notice of Errata to Public Service's RRR, p. 1).

[63] UCA's RRR, pp. 9-10.

[64] UCA's RRR, p. 3.

effectively should it no longer be cost-effective or appropriate to move forward with mitigation or local stakeholder processes and siting.[65]

52. Regarding the backup for Bid 1029, consistent with the Phase II Decision we agree with the Company that Bid 1016 is supported as an appropriate backup bid on this record. Approving the Company's backup bid request for Bid 1029 best helps the Commission maintain its Phase II determinations and will allow the Company to pivot quickly in the event it is necessary to adjust Bid 1029, given the unique situation.

53. The replacement bids that UCA offers as alternatives in its RRR Application are not supported as sufficiently and do not allow the Company to pivot as readily. For instance, while Bid 375 that Staff supported in its Phase II comments is included in the backup bid portfolio, Staff acknowledges that it did not run reliability testing on this replacement scenario, and it is far from clear that a 200 MW solar project (Bid 375) could seamlessly replace a 500 MW wind project (Bid 1029). We have similar concerns about UCA's proposal to use Bid 0562 to replace Bid 0045, and then use Bid 1024 to replace Bid 1029. Bid 0562 is not included in the backup portfolio and it is unclear that this smaller sized project could suitably replace Bid 0045; Bid 0562 is 252 MW while Bid 0045 is 375 MW.[66]

54. Regarding the Company's request to adjust Bid 1029's PIM to account for impacts to projected operations and economics resulting from changes made to address viewshed and cultural impact issues, we grant this request, in part. If the Company brings forward a CPCN for Bid 1029 and Public Service demonstrates verifiable costs associated with mitigating viewshed

[65] Notably, and as addressed in the Phase II Decision, the Commission's oversight in ERP processes does not abrogate the role of local governments to approve siting decisions for facilities, plants, or system. § 40-5-101(1)(a), C.R.S.

[66] *See* 120-Day Report (Appendix P).

and cultural impacts, the PIM for Bid 1029 may be adjusted to account for these verifiable costs—to a point. The adjusted PIM for Bid 1029 will be based on the cost and performance metrics of Bid 1016, as contemplated in the Phase II bidding. The details of the allowable adjustments, if necessary, can be worked out in the follow-on CPCN, but if Bid 1029 can proceed in such a way that addresses any impacts to the Sand Creek Massacre National Historic Site and is cost effective compared to the as-bid pricing of Bid 1016—customers and the Company should both win. However, if the adjustments to Bid 1029 would cause it to be more expensive than the as-bid pricing for Bid 1016, Public Service should be incentivized to simply switch to Bid 1016.

55. Ultimately, Public Service needs to ensure that if Bid 1029 goes forward, the Company has worked with interested stakeholders to address potential impacts to the Sand Creek Massacre National Historic Site. However, the Company must prudently use its discretion and pivot to Bid 1016 if that becomes the more economic option.

56. By approving an appropriate backup bid and addressing performance incentives, the Company is sufficiently supported in moving forward appropriately with Bid 1029 to the extent it remains viable and cost-effective. With these clarifications we therefore find UCA and Staff's requests are appropriately denied. Further clarification regarding our expectations is unnecessary. We also do not reject the bid outright. The Company in its ongoing conferrals with stakeholders, Tribal Nations, and local authorities is best situated to understand if mitigation efforts are cost-effective and possible regarding Bid 1029, or if it should move to a backup bid that becomes less costly relative to Bid 1029 as more certainty around mitigation and other costs develop.

57. The Company's RRR requests regarding Bid 1029 are granted, in part, consistent with the discussion above. UCA and Staff's requests are denied.

E. Backup Bids

1. Utility Owned Generation Backup Bid Selection Process

a. Summary of Phase II Decision

58. In the Phase II Decision, we found merit in the concerns raised by Staff, the Colorado Independent Energy Association (CIEA), and COSSA/SEIA regarding the Company's perverse incentives of replacing an IPP project with a backup Company-owned project. The Commission generally adopted Staff's suggested approach for selecting backup bids in which the Company retains the burden of proving that any Company-owned backup project was the prudent replacement and would provide a robust alternatives analysis as part of the follow-on CPCN proceeding.[67]

59. The Phase II Decision makes clear that these additional guardrails also apply when the Company uses its Right of First Offer (ROFO) to purchase a failing PPA project and when the Company replaces a Company-owned project with a Company-owned backup.[68] We emphasized, however, that this backup bid selection process must move quickly, especially in instances in which the replacement is like for like.[69]

b. Public Service's RRR Application

60. In its RRR, Public Service requests significant changes to the process for selecting Company-owned backup bid. The Company acknowledges concerns regarding sufficient process "when a Company-owned backup bid may replace an IPP project, in the event an IPP project

[67] Phase II Decision, pp. 93-94.
[68] Phase II Decision, pp. 93-94.
[69] Phase II Decision, p. 94.

cannot go forward"[70] but argues that these concerns must be counterbalanced with an efficient process to avoid an outcome where a prolonged CPCN process necessitates substantial modifications to a Company-owned backup project. To replace the process set forth in the Phase II Decision, Public Services proposes the following three steps: (1) a conferral with Staff; (2) the intended filing of a comprehensive CPCN package with all backup bids; and (3) the use of a notice process to activate a Company-owned backup bid in the event it is needed to replace a project that cannot go forward.[71]

61. Regarding the first step (conferral with Staff) the Company states that it would confer with Staff both before filing the packaged CPCN application in Step 2 and before advancing any specific Company-owned backup bid to meet a system need in Step 3.[72]

62. As to the second step (a packaged CPCN filing), Public Service states that it is "currently planning to commence a CPCN filing where all Company-owned backup bids are brought forward simultaneously for CPCN approvals."[73] The Company states that this "will be needed for current contractual commitments and in order to advance backup projects expeditiously."[74] The Company states that this packaged CPCN will set forth the specifics of each project and reasonably foreseeable replacement scenarios where the Company would need to activate a particular backup bid. Public Service asserts that this "provides the alternatives analysis the Commission requests." In addition, Company suggests that in this packaged CPCN filing it

[70] Public Service's RRR, p. 8. The Company fails to acknowledge the requirement in the Phase II Decision that additional protections are also warranted when the Company uses its ROFO and when the Company replaces a Company-owned project with a Company-owned backup. (Phase II Decision, ¶¶ 237-38).

[71] Public Service's RRR, p. 8.

[72] Public Service's RRR, pp. 8-9.

[73] Public Service's RRR, p. 9.

[74] Public Service's RRR, p. 9.

might request a "milestone payment recovery or similar structure" if necessary to preserve certain projects.[75]

63. As for the third step (notice), Public Service states that the Company will provide notice to the Commission prior to activation of the Company-owned backup bid approved in the packaged CPCN proceeding (step 2). The Company states that the notice would flag whether the activation is consistent with the analysis in the packaged CPCN process and, to the extent the circumstances changed, the Company would explain why a particular backup bid was being activated, and the Commission could quickly determine whether further process was necessary.[76]

64. Public Service argues that this three-step process is consistent with the backup bid process ordered by the Commission but is designed to make the process "nimble" to ensure appropriate timing to meet system needs.[77]

c. Findings and Conclusions

65. The Commission denies Public Service's request to modify the backup bid selection process. For context, pursuant to the backup bid selection process that the Phase II Decision approves, whenever a failed project (either Company-owned or IPP) is being replaced with a Company-owned project or the Company is exercising its ROFO, the Company must do the following:

a. Notify the Commission and provide additional evidence and detail regarding the steps taken to attempt to remediate the failed project;
b. Retain the burden to prove that the Company-owned project was the prudent replacement;

[75] Public Service's RRR, p. 9.
[76] Public Service's RRR, p. 10.
[77] Public Service's RRR, p. 10.

c. Provide robust alternatives analysis as part of the follow-on CPCN proceeding filed for the Company-owned generation project. In other words, such a generating resource would not qualify for a limited-scope CPCN application.[78]

66. Under the Company's RRR proposal, Public Service would not be required to show what attempts the Company made to remediate the failed project, the Company would only provide scenarios in which the Company-owned backup bid was activated, and the only CPCN proceeding would be the packaged CPCN in which several Company-owned backup bids are simultaneously evaluated together. Perhaps most troubling, the Company's proposed process does not seem to include an alternatives analysis regarding Company-owned backup bids versus available IPP backup bids. Without some analysis and transparency regarding why Public Service is moving forward with a Company-owned backup bid as opposed to an IPP backup bid, the Company's proposed process ignores the risk of perverse incentives that Staff, CIEA, and COSSA/SEIA raised in their comments to the 120-Day Report and which the Commission found persuasive in our Phase II Decision.[79] This is true even if the Company-owned backup bid would replace a Company-owned project.

67. We remain convinced that whenever the Company moves forward with a Company-owned backup bid, some process and explanation is necessary to show that the Company-owned backup bid is the most prudent alternative. This necessarily entails some type of alternatives analysis that compares the Company's proposed backup bid against IPP backup bids. Ideally, this alternatives analysis is grounded in the as-bid economics of the respective projects as depicted on Appendix P of the 120-Day Report.

[78] *See* Phase II Decision, ¶ 238; Staff's Comments, p. 66.
[79] Phase II Decision, ¶ 237.

68. The Company's proposed conferral with Staff does not remove our concerns. Private conferral with Staff is unsupported and potentially could cause delays. For example, it is unclear what information the Company would provide Staff, how much time Staff would have to analyze the information, and the options Staff would have if it had concerns. In addition to the transparency benefits, the Commission's Phase II backup bid processes can better be directed and expedited as necessary by the Commission.

69. With the limited exceptions for specific backup bid considerations supported on this record for the reasons discussed, the process approved in the Phase II Decision remains appropriate.

70. While we deny Public Service's RRR Application on this point, we acknowledge the importance of being able to quickly shift to backup projects as circumstances require.[80] In this vein, we invite the Company to provide a supported petition for a waiver of the backup bid selection process (preferably jointly with other stakeholders). While there is insufficient support here to waive the process as proposed by the Company, specific circumstances and a supported petition for waiver are in no way prohibited for consideration. We commit to both the Company and bidders to do what we can to quickly shift appropriately to backup bids when needed.

71. Finally, we note Public Service's indication in its RRR Application that it might seek "milestone payment recovery or similar structure" if necessary to preserve certain projects.[81] Although the Company does not present a specific milestone payment structure for our approval in its RRR Application, we are open to further exploring this concept in future proceedings for both Company-owned and IPP backup bids. Depending on the specifics of such milestone

[80] On this point, we reaffirm our conclusions in the Phase II Decision that the process must move forward quickly, especially in instances in which the replacement is like for like. (Phase II Decision, ¶ 238).

[81] Public Service's RRR, p. 9.

payments and after developing a robust record on the issue, this concept might be an appropriate tool to help both Company-owned and IPP projects remain viable.

2. IPP Backup Bid Selection Process

72. In its RRR Application, the Company seeks to clarify the selection process for IPP backup bids. The Company states that it understands that if the activated backup bid is an IPP, Public Service would simply notify the Commission and explain the circumstances and then commence negotiations with the IPP. The Commission would not need to issue any type of approval for the IPP backup bid.[82]

73. The Commission grants the Company's RRR on this point and confirms Public Service's understanding regarding the selection process for an IPP backup bid. When the Company activates an IPP bid, there is little risk of perverse incentive. The Company should thus have the flexibility to move forward quickly with an appropriate IPP backup.[83]

3. Bid 0235 (PPA Gas Unit) Replacement

a. Summary of Phase II Decision

74. Bid 0235 was a 219 MW gas IPP project that was the only non-Company-owned gas resource selected in the Alternative Portfolio. The Company's Preferred Portfolio and UPP only contain Company-owned gas resources. The inclusion of non-Company-owned gas resources in the Alternative Portfolio was a factor supporting our decision to modify the CEP. For instance, we found that diversifying the ownership of the gas resources reduces the risks that customers will be saddled with future costs associated with Company-owned gas resources.[84]

[82] Public Service's RRR, pp. 10-11.

[83] We acknowledge Public Service's statements regarding moving Bid 0151 (a 300 MW solar IPP bid) into the backup bid pool. (Public Service's RRR, p. 11.) The Company does not seek any specific relief in this regard, and we see no reason to comment on the Company's plans regarding Bid 0151.

[84] Phase II Decision, ¶¶ 108,

b. Public Service's RRR

75. Public Service states that on January 10, 2024, the bidder for Bid 0235 informed the Company that the bid was withdrawn, and the project would not be available for the Public Service system. Public Service further states that "[i]t is expected the project may be offered to a different off-taker."[85]

76. Reiterating that "reduction in dispatchable resources is not tenable" Public Service requests that the Commission approve the replacement of Bid 0235 and Bid 0997 with Bid 1000.[86] Public Service recounts that Bid 1000 is a Company-owned project with two 200 MW combustion turbines (CTs) that was included in the UPP. Bid 1000 would take the place of withdrawn Bid 0235 and also supplant the approved Bid 0997. (Bid 0997 is similar to Bid 1000 but only includes one Company-owned 200 MW CT). In other words, Bid 1000 contains both the standalone 200 MW of Bid 0997 the other 200 MW CT, for a total of 400 MWs. The Company notes that replacing Bid 0235 and Bid 0997 with Bid 1000 would modestly reduce the level of gas in the approved portfolio by 19 MW.[87]

c. Findings and Conclusions

77. We reject Public Service's request to replace—at this time—the 219 MW PPA gas resource (Bid 0235) with a Company-owned gas resources (Bid 1000). Public Service does not assert—let alone demonstrate through record evidence—that Bid 1000 is the most prudent option to replace Bid 0235. The Company shall go through the approved backup bid selection process in which the Company has the burden of establishing whether its Company-owned backup bid (Bid 1000) is more prudent than a combination of other available backup bids, such as Bid 0510 and

[85] Public Service's RRR, p. 2.
[86] Public Service's RRR, pp. 2-3.
[87] Public Service's RRR, p. 3.

Bid 0514.[88] In addition, we direct Public Service to address in this future process whether there are other PPA gas resources such as Bid 1061 that could also help contribute as a viable replacement for Bid 0235. We acknowledge that Public Service has raised reliability concerns in the context of Bid 1061 being the sole replacement for a new 200 MW CT,[89] but we want to further explore whether other viable options, including specifically Bid 1061, in combination with other resources could help serve system needs.

78. As set forth in the Phase II Decision, diversifying the ownership of the gas resources can help reduce risks to ratepayers and such diversification was seen as a virtue in the Alternative Portfolio. We therefore have a strong interest in evaluating whether there are other PPA gas resources that could replace Bid 0235, instead of reverting to the Company-owned Bid 1000. Thus, Public Service's request to move forward with Bid 1000 is denied until there is sufficient and consistent process establishing that this bid is the best available option to replace Bid 0235. The record in this case is closed, and Public Service has not established that backup Bid 1000 is the best available option where potential alternatives might exist.

79. Finally, we reiterate our openness to exploring in a future proceeding whether milestone payments or a similar payment structure could be beneficial for Company-owned and IPP projects. Although this concept would necessarily need to be fleshed out and supported, we are interested in evaluating whether such a structure could help keep projects viable, especially in instances like this where the preferred project has failed.

[88] Bid 0510 and Bid 0514 are both existing PPA resources that are available for relatively short-term extensions (*e.g.* Bid 510 is being offered with a PPA term of seven years). (120-Day Report (Appendix P), p. 1.)

[89] Phase II Decision, ¶ 127.

4. COSSA/SEIA Backup Bid Requests

a. Backup Bid Selection Sequence

80. COSSA/SEIA asks that the Commission direct Public Service to first replace failed projects with projects that were selected in the UPP but not the Alternative Portfolio and only after that use bids on the Company's backup bid list. COSSA/SEIA argues that the current approach established in the Phase II Decision is unnecessarily vague, leaves too much to Company discretion, and does not allow project developers to assess whether their project remains viable. COSSA/SEIA reasons the Commission should do this to ensure that bidders can evaluate the likelihood that their project will be selected.[90]

81. The Commission denies COSSA/SEIA's request to require Public Service to select backup bids based on whether they were selected in the UPP. The Company should use its discretion to select the most appropriate backup bid available, regardless of whether the backup bid appears in the backup portfolio or is one of the projects that was selected in the UPP, but not in the Alternative Portfolio. For similar reasons, we clarify that Public Service is not required to select backup bids on a like-for-like basis. Transparency and process regarding the use of the Company's discretion to select backup bids is more appropriate than a bright-line requirement to select like-for-like bids, which might result in the optimal backup bid being passed over.

b. Explanation of Failed Bids

82. COSSA/SEIA requests that the Commission require Public Service to explain any "failed" projects so that the Commission and relevant stakeholders can determine whether projects did not reach a final PPA because of developer-side issues or because the Company has adopted unworkable negotiation tactics. COSSA/SEIA argues that the Commission should adopt this

[90] COSSA/SEIA's RRR, pp. 11-12.

requirement because "the Company has illustrated that it is and will continue to act on the perverse incentives inherent in the final bid negotiation and backup bid processes."[91]

83. We deny COSSA/SEIA's request. As referenced above, under the approved backup bid selection process, whenever a failed project is being replaced with a Company-owned project, Public Service is required to provide additional evidence and detail regarding the steps taken to attempt to remediate the failed project.[92] In the context of this existing protection, COSSA/SEIA's request is unnecessary.

5. Public Service Additional Backup Bid Requests

a. Bid 0044 Replacement

84. Public Service notes that the Phase II Decision approves Bid 0254 as the backup bid for Bid 0044, but the Company notes that "the Commission may have overlooked Bid 0295, which was the Company's originally preferred option in the UPP."[93] The Company states that Bid 0295 is larger than Bid 0254 with 500 MW nameplate capacity as compared to 291 MW nameplate capacity for Bid 0254, but it also has a lower LEC. Given that Bid 0044 cannot move forward, Public Service asks that the Commission confirm whether it should be replaced with Bid 0254 per the Phase II Decision or Bid 0295, which is larger but less expensive on a Levelized Cost of Energy (LEC) basis.[94]

85. Bid 0254 is a 291 MW PPA wind bid with an ISD of 2026.[95] Bid 0295 is a 500 MW PPA wind bid with an ISD of 2026. Based on this record, we see no issue with authorizing Public

[91] COSSA/SEIA's RRR, p. 8.
[92] Phase II Decision, ¶ 238; Staff's Comments, p. 66.
[93] Public Service's RRR, p. 3.
[94] Public Service's RRR, pp. 3-4.
[95] Public Service's Response Comments, p. 27.

Service to move forward with Bid 0295 instead of Bid 0254 and therefore grant Public Service's request on this point.

b. Backup Bid for Bid 0011

86. As part of the change from the UPP to the Alternative Portfolio, the model selected Bid 011 (a 50 MW Company-owned gas resource in the Alamosa area) instead of Bid 0986 (a 28 MW Company-owned gas resource in the Alamosa area).

87. In its RRR, Public Service states that it is undertaking next steps to bring Bid 0011 to fruition but states that "it would be beneficial and efficient to designate a backup bid in the event that Bid 0011 cannot move forward."[96] Public Service requests that the Commission designate Bid 0986 as the specified backup bid.

88. The Commission sees no issue based on this record with designating Bid 0985 as the backup bid for Bid 0011. Both are Company-owned gas resources of similar size in similar locations. Given the Company's assertions that new firm dispatchable generation in the Alamosa area is necessary for reliability together with the fact that the available bids are Company-owned,[97] the Commission sees no benefit to requiring the Company to prove that Bid 0985 is the most appropriate backup bid for Bid 0011.

89. Although we grant the Company's RRR request on this point, Bid 0011 appears to have certain advantages over Bid 0985. In the 120-Day Report, Public Service notes that because of the unique design of Bid 0011, it is already capable of 100 percent clean fuel combustion and can switch between fuels like hydrogen, ammonia, and biogas "on the fly."[98] These characteristics

[96] Public Service's RRR, p. 4.
[97] 120-Day Report, p. 39.
[98] 120-Day Report, p. 124.

of Bid 0011 appear especially advantageous given Colorado's goal to achieve 100 percent clean energy.

c. Bid Reference Correction

90. One of the changes in the UPP that the Company notes in its Response Comments is the replacement of Bid 0045 (a Company-owned wind project) with Bid 1024 (another Company-owned wind project).[99] In the Phase II Decision, the Commission states that the Company may replace Bid 0045 with Bid 1024 without going through the established backup bid process.[100]

91. In its RRR, Public Service explains that the Alternative Portfolio does not contain Bid 0045 but contains its variant, Bid 0043. The Company states that, like Bid 0045, Bid 0043 cannot move forward and should be replaced with Bid 1024. For clarity of record, the Company asks that the reference to Bid 0045 in Paragraph 239 be changed to Bid 0043 given the move to the Alternative Portfolio.[101]

92. The Commission grants this requested clarification. The reference to Bid 0045 in Paragraph 239 of the Phase II Decision is changed to Bid 0043.

6. Staff's Additional Backup Bid Requests

a. Required List of Updated Projects and Backup Bids

93. The Phase II Decision approves the list of backup bids provided in the Company's Response Comments but also gives Public Service discretion to adjust the portfolio of backup bids as necessary given the switch to the Alternative Portfolio.[102]

[99] Public Service's Response Comments, p. 18.
[100] Phase II Decision, ¶ 239.
[101] Public Service's RRR, p. 24.
[102] Phase II Decision, ¶ 235

94. Noting the discretion the Commission afforded Public Service regarding the backup bid portfolio, Staff argues that the Company should be required to file in this Proceeding within 30 days a detailed list of projects in the approved portfolio plus an updated list of backup bids. Staff reasons that such a filing will help parties (including Staff) properly monitor the Company's activities as it implements the Phase II Decision.[103]

95. The Commission agrees with Staff and requires the Company to file in this Proceeding within 30 days, a list of the approved projects in the Alternative Portfolio as well as an updated list of backup bids.

96. In addition to Staff's request, we encourage Public Service to specify, to the extent practicable, the estimated sequence of backup bids. For instance, if there are four solar backup bids, we encourage the Company to try to provide guidance as to which backup bids it will likely turn to first if a project fails. This would address a concern raised by COSSA/SEIA in its RRR that bidders should be able to evaluate the likelihood of their backup bid ultimately being selected. We also encourage the Company, to the extent practicable, to refresh the backup bid portfolio for wind projects. Due to project failures, Bid 1029, and the elimination of the MVLE, the backup portfolio for wind projects appears to be depleted.

b. No Backup Bids on the MVLE

97. The Phase II Decision gives the Company discretion to adjust the backup bid portfolio given the switch to the Alternative Portfolio and notes that it "would be reasonable to include as a backup bid any bid within the UPP that is not in the Alternative Portfolio."[104]

[103] Staff's RRR, pp. 5-6.
[104] Phase II Decision, ¶ 235.

98. Staff argues that this allows the Company to include as a backup bid a project that interconnects to the MVLE, which would be inconsistent with other parts of the Phase II Decision. Staff asks that the Commission clarify that the Company cannot deem projects that interconnect to the MVLE as backup bids. [105]

99. We grant Staff's request on this point and clarify that projects that rely on the MVLE are ineligible for backup bid status for purposes of this Proceeding.

F. PPA Negotiations, Repricing, and ISD Extensions

1. Motion to Respond

100. In its RRR, COSSA/SEIA makes broad allegations that Public Service is mishandling PPA negotiations in an effort to expand the share of Company-owned projects. For instance, COSSA/SEIA alleges that after the 120-Day Report the Company has issued another, heavily redlined Model PPA and is presenting the modified PPAs on a take-it-or-leave-it basis.[106] COSSA/SEIA attaches redlined versions of the PPA purportedly showing the Company's "required" modifications and lists numerous specific examples of what it claims are problematic PPA provisions.[107] COSSA/SEIA stops short, however, of alleging that any of the PPA modifications violate a Commission rule or decision.

101. In its Motion to Respond, Public Service states that it seeks to provide a targeted response COSSA/SEIA's allegations in its RRR that the Company is mishandling PPA negotiations to expand the share of Company-owned projects. Public Service "categorically denies" these allegations.[108] In the Motion to Respond, the Company indicates that no parties to this Proceeding

[105] Staff's RRR, p. 5.
[106] COSSA/SEIA's RRR, pp. 2-4.
[107] COSSA/SEIA's RRR, pp. 5-7.
[108] Motion to Respond, p. 1.

oppose the Motion (including COSSA/SEIA) but that COSSA/SEIA and CIEA reserve their right to respond to the Motion.

102. Public Service goes on to assert that pursuant to Commission Rule 1506(b), the allegations in COSSA/SEIA's RRR warrant a response.

103. We grant the Motion to Respond and consider Public Service's Response to COSSA/SEIA's RRR Application in our determinations. The Motion to Respond appears to be unopposed, and no party filed response. In addition, Public Service demonstrates that COSSA/SEIA's RRR Application attempts to introduce facts not in evidence and thus there is good cause for a response pursuant to Rule 1506(b). More specifically, the attachments COSSA/SEIA includes with its RRR Application are replete with information that is not otherwise included in the record.

2. Commercially Reasonable PPA Negotiations

a. COSSA/SEIA's RRR Application

104. In its RRR Application, COSSA/SEIA asserts that the Company is refusing to allow IPPs to make any substantive modifications to PPA terms that the Company revised in Phase II and argues that—if allowed to continue—this will increase the likelihood that projects are rendered unfinanceable or that IPPs withdraw their bids. Accordingly, COSSA/SEIA requests that the Commission direct the Company to negotiate the terms of a final PPA in a commercially reasonable manner with project bidders, including a direction that the Company must reasonably consider revisions to or rejections of new terms that it has never previously described as non-negotiable. COSSA/SEIA also asks that the Company be prohibited from swapping a PPA bid for a backup

bid for the sole reason that the primary bidder refuses the Company's newly added model PPA terms, provided that the primary bidder is otherwise abiding by its bid price and other bid terms.[109]

b. Public Service's Response

105. Public Service asserts that it has no interest in seeing projects fail, regardless of business model, ownership structure, or generation type and that it "will negotiate in good faith to make projects a reality."[110] Nevertheless, the Company maintains that it will not accept "any counterproposal on any term."[111] The Company argues that IPPs must have an incentive to deliver and that in order to protect ratepayers there must be reasonable penalties if an IPP "walks away" from a project. Public Service explains that PPA terms that permit project failures, with little to no protection for customers, will ultimately cost customers and thus these types of terms are "non-negotiable."[112]

c. Findings and Conclusions

106. We will refrain from resolving discrete disputes about the PPA terms at this stage in the process and on this record. While some of the new provisions regarding unquantified change of law risk, force majeure, and forced labor requirements seem inappropriate and may cause financing concerns, taken as a whole they do not seem to rise to the level of bad faith. Indeed, some of the complaints that COSSA/SEIA raise seem overstated, including, for example, the issue regarding the Company's approach for determining the acceptability of corporate guarantees in light of the other two standard alternatives.[113] Given the context of requests and stage of proceedings here, the Commission does not insert itself into negotiations, or make specific

[109] COSSA/SEIA's RRR, pp. 7-8.
[110] Public Service's RRR Response, p. 5.
[111] Public Service's RRR Response, p. 5.
[112] Public Service's RRR Response, p. 7.
[113] *See* COSSA/SEIA's RRR, p. 6.

findings regarding terms presented by COSSA/SEIA in the documents attached to the RRR Application.

107. Ultimately, however, we grant COSSS/SEIA's request in so far as we direct the Company to engage in PPA negotiations in a commercially reasonable manner for the material changes it has proposed subsequent to the approval of the model contract. We note that the Company has already committed to "negotiate in good faith to make projects a reality."[114] This does not mean, however, that Public Service is required to accept any counterproposal on any term. Rejecting unreasonable modifications is still commercially reasonable. Along these lines, we reject COSSA/SEIA's related request to prohibit the Company from moving to a backup bid if an IPP refuses to agree to the Company's modifications. If an IPP is requesting unreasonable modifications, Public Service is in no way prohibited from moving on as appropriate and necessary.

3. New Transmission PPA Provisions

108. COSSA/SEIA asks the Commission to clarify that the Company's new PPA provisions addressing transmission delays that are different from the original model PPA included in the Company's Request for Proposals (RFP) are not non-negotiable and are open for and subject to negotiation.[115] COSSA/SEIA asserts that under the Company's modifications to the model PPA, transmission delays are no longer treated as force majeure events consistent with the Model PPA approved in Phase I. Instead, the revised PPA only offers limited schedule relief for transmission-related delays.[116]

[114] Public Service's RRR Response, p. 5.
[115] COSSA/ SEIA's RRR, p. 11.
[116] COSSA/ SEIA's RRR, p. 10.

109. The Commission grants COSSA/SEIA's request in part. IPPs and Public Service are not prohibited from further negotiating and modifying the most recent versions of the PPAs, but the Commission also does not require further negotiation. As noted in the Phase II Decision, Colorado currently does not have a conforming bid policy where bidders have to bid the model agreements "as-is." Although we have expressed interest in moving towards a conforming bid policy in the 2024 JTS, in this Proceeding there is no such requirement. Thus, Public Service and the respective IPPs have discretion to negotiate PPA terms as it sees fit, so long as the resulting PPA complies with the Commission's directives.

4. ISD Extensions

110. In the Phase II Decision, the Commission authorized Public Service to extend the ISDs of IPP projects by up to 75 days as well as any delays in transmission assets to which individual projects interconnect.[117] In addition, backup bids may have an ISD extension by the number of days after the Phase II Decision that the backup bid is approved to move to the selected portfolio.[118]

111. In its RRR, Public Service asks that the Commission clarify that all projects, regardless of ownership structure, have the same opportunity for ISD extension. The Company asserts that there is no credible reason to extend flexibility to IPP ISDs without correspondingly extending the same to Company-owned projects.[119] Public Service also seeks clarification that the ISD extension established in the Phase II Decision for backup bids applies to all backup bids,

[117] Phase II Decision, ¶ 272.
[118] Phase II Decision, ¶ 271.
[119] Public Service's RRR, p. 22.

including the "new" backup bids comprised of the projects included in the UPP that are not included in the Alternative Portfolio.[120]

112. The Commission grants the Company's requests. We see no reason to treat IPP bids and Company bids differently in this regard, and it similarly makes sense that all backup bids, including those originating from the UPP, have an ISD extension.

G. Transmission Caused Repricing and ISD Extensions

113. The Phase II Decision denies CIEA's request to allow backup bids to reprice but holds that "repricing is allowed for backup bids in the case where the transmission costs provided in the RFP have changed."[121] This was consistent with Public Service's Response Comments in which the Company "supports allowing price increases in the limited circumstance where a transmission cost estimate is different than the estimate provided as part of the Request for Proposal, but that is the only basis for change (notwithstanding force majeure) and equally applicable to any bid the Company moves forward with."[122]

114. In addition, the Phase II Decision authorizes Public Service to extend ISDs upon application by IPPs by up to 75 days as well as any delays in transmission assets to which individual projects interconnect.[123] This was also consistent with Public Service's position in Response Comment that "delays in generation resource ISDs … due to transmission-related delays, such as delays associated with interconnection, backfeed, and substation construction, shall be considered reasonable."[124]

[120] Public Service's RRR, p. 22.
[121] Phase II Decision, ¶ 275.
[122] Public Service's Response Comments, p. 41.
[123] Phase II Decision, ¶ 272.
[124] Public Service's Response Comments, p. 104.

115. COSSA/SEIA asks that the Commission revise the Phase II Decision to clarify that all bidders (not just backups) may reprice bids when a project suffers increased costs or delays that cause a missed commercial operation date (COD) due to overdue interconnection studies or the Company's failure to meet its own interconnection milestones. COSSA/SEIA argues that this modification is warranted based on the rigid terms that the Company is requesting in PPA negotiations and "the Company's own acknowledgement that transmission-related delays are all but certain."[125]

116. The Commission grants COSSA/SEIA's request, in part. Where a transmission cost estimate is different than the estimate provided as part of the RFP, both backup bids and selected projects should be able to adjust for this price increase on a one-for-one basis. Given that the Company is the entity responsible for the initial transmission estimates and has alternative mechanisms for recovering transmission-related cost increases, this one-for-one repricing opportunity only applies to IPP bids. Conversely, we deny COSSA/SEIA's related request to allow repricing whenever an overdue interconnection study or other interconnection delay causes a project to miss its COD. The Phase II Decision already permits ISD extensions based on transmission delays, but projects are not permitted to reprice for interconnection delays.

117. Finally, we expect and encourage the Company to track the accuracy of the transmission cost estimates it provides in the RFPs. We anticipate that in future ERP proceedings, information regarding the difference between the initial transmission estimates provided in the RFP and the actual transmission costs will be helpful for the Commission and parties. The accuracy of estimates is of importance as it relates to fair competition between IPP projects and utility-owned generation projects, as well as the broader cost-effectiveness comparison of bids,

[125] COSSA/SEIA's RRR, pp. 10-11.

to ensure the outcomes are properly optimized around total costs. We encourage the Company to include this information in its initial filings in the 2024 JTS.

H. PIMs

1. Landing Spot vs. Progressive Method

a. Summary of Phase II Decision

118. In the Phase II Decision, the Commission established a cost to construct PIM and an operational PIM. For the cost to construct PIM, there is a five percent deadband around the baseline in which Public Service earns no incentive or disincentive. Outside of the five percent deadband, however, the Company and ratepayers would share any cost overruns or savings based on three symmetrical tiers. For instance, if actual construction costs are more than five percent through ten percent of the baseline, Public Service would bear 40 percent of the cost overruns. If construction costs are more than ten percent through 15 percent of the baseline, Public Service would bear 50 percent of the cost overruns. The operational PIM follows a similar structure in which there is a five percent deadband around a baseline (the as-bid LEC of a project) with symmetrical tiers outside of the five percent deadband.[126]

b. Public Service's RRR Application

119. In its RRR, the Company characterizes the PIM methodology the Commission adopts for both the operational PIM and the cost to construct PIM as the "Landing Spot Method," because it applies a fixed sharing percentage to the difference between a project's point cost estimate or LEC and its actual final construction cost and achieved LEC. The Landing Spot Method makes no allowance for the five percent deadband or any previous cost sharing tier.

[126] Phase II Decision, ¶¶ 184, 186-88

The Company contrasts this with what it calls the "Progressive Method," in which the incentive or penalty would be calculated based on the difference between a project's point cost and its final construction cost, after first adjusting for both the deadband and any previous penalty/incentive tier.[127]

120. The Company points out that the Landing Spot Method has the shortcoming that a project that comes in at one dollar below the 95 percent to 105 percent deadband would be eligible for an incentive of 40 percent of the full difference from the point cost, whereas that incentive would not exist if the project cost just a dollar more. The Company notes that this method could result in ratepayers paying higher costs for a project that comes in farther below the baseline. The Landing Spot Method has the inverse shortcoming for cost overruns, where a small excursion above 105 percent of the point cost could trigger a disproportionate penalty. The Company states that this situation is also in violation of the Commission's articulated principle that PIMs "should establish penalties or incentives that scale with the degree of success or failure in achieving the pre-defined metrics, but should be neither excessively punitive nor lucrative and must be in conformance with existing law …."[128]

121. The Company argues that the above shortcomings and the perverse incentives for unproductive gamesmanship to achieve or avoid the next tier of incentives or penalties could be avoided by adopting the Progressive Method instead.[129]

c. Findings and Conclusions

122. The Commission denies Public Service's request and retains the Landing Spot methodology, for now. We are sympathetic to the Company's points about providing more linear

[127] Public Service's RRR, p. 12.
[128] Public Service's RRR, p. 13.
[129] Public Service's RRR, p. 13.

and gradual adjustments to the incentives and disincentives under the PIMs, and it appears that the Company's proposed Progressive Method would help accomplish this. However, under the Progressive Method, both incentives and disincentives are significantly reduced compared to what they would be under the Landing Spot Method, which was not properly addressed by the Company in the RRR to provide an alternative that would be comparable to the Commission's Phase II Decision on the PIMs. To achieve similar amounts of incentives and disincentives, the Commission would need to further modify the PIM calculations beyond what Public Service contemplates in its RRR Application. On this record, we decline from doing so.

123. While we will retain the Landing Spot Method for purposes of this Decision, we would be open to moving to the Progressive Method in the future. In future CPCN proceedings, Public Service could (preferably with other parties) request to implement the Progressive Method in such a way that is supported and roughly maintains the overall amounts of incentives and disincentives.

2. Timing PIM

124. In connection with the operational PIM, the Commission expressed a "strong interest" in a mechanism to incentivize timely completion of Company-owned projects per the timing anticipated in the modeling and bidding process. The Commission suggested that the operational PIM could be adjusted such that the LEC calculations commence on the as-bid ISD of the project.[130] The Commission stopped short of adopting a timing mechanism in Phase II but stated its intent to "evaluate in the follow on CPCN proceedings how best to align the Company's incentives regarding the completion of generation projects."[131]

[130] Phase II Decision, ¶ 193.
[131] Phase II Decision, ¶ 193.

125. In its RRR, the Company acknowledges that the Commission did not adopt a timing mechanism but nonetheless seeks assurance that "a separate timing PIM is not required for this ERP cycle because of the breadth of the PIM framework established by the Commission in Phase I and through the Phase II Decision and the incentives already created by the framework."[132]

126. The Company argues that cost to construct PIM and the future Emissions PIM already cover the timing element given that project delays will generally increase construction costs and—for renewable projects—project delays would hinder the Company's emission reduction progress. In addition, Public Service notes that the cost to construct PIM includes the allowance for funds used during construction and states that delays in project construction would increase capitalized interest costs, which ultimately could result in the Company absorbing a significant amount of money.[133] The Company thus argues that a standalone timing PIM would not only introduce unnecessary complexity but would duplicate already existing timing incentives.[134]

127. The Commission denies the Company's request as premature. In future CPCN proceedings, the Commission may want to consider a timing PIM based on the facts and circumstances at that time. We find unpersuasive the Company's arguments that any future timing PIM would duplicate existing timing incentives. It is far from clear that all project delays will increase construction costs. Moreover, Public Service has not yet proposed an emissions reductions PIM, so we cannot evaluate the timing incentives of that future PIM. In short, the Commission will be better able to determine the appropriateness of a timing PIM in the follow-on CPCN proceedings, so we decline at this time from an outright prohibition of any future timing

[132] Public Service's RRR, p. 14.
[133] Public Service's RRR, p. 14.
[134] Public Service's RRR, p. 15.

PIM, but acknowledge that any such PIM will need to reflect the facts and circumstances at that time.

3. Treatment of Curtailments

128. In the Phase II Decision, we included our intention to continue evaluating in the follow on CPCN proceedings unresolved details regarding how to make the operational PIM appropriately indifferent to curtailments. The Commission also notes, however, that we do "not intend for the operational PIM to somehow shift the risk of curtailments on to the Company."[135]

129. The Company seeks clarity regarding the Commission's intent to make the operational PIM "indifferent to curtailments," asserting that there is a potential for substantial litigation regarding the meaning of "indifferent."[136] Public Service warns that lack of clarity on this issue could easily derail a time sensitive CPCN proceeding and requests that the operational PIM not be a curtailment management PIM. The Company asserts that any implemented operational PIM must have a specified treatment for curtailments in which curtailed volumes are included as if they were generated for purposes of calculating the LEC comparison. Public Service asserts that this treatment is consistent with IPP contracting structures and avoids perverse incentives.[137]

130. In general, we agree with Public Service that the operational PIM should not be a curtailment-management PIM. We do not want to create a perverse incentive in which the Company is incentivized to curtail others but not itself. Our expectation is that the emissions reduction PIM will more holistically address the issue of curtailments. Nevertheless, curtailments should not be used to mask poor operational performance of Company-owned generation. If the

[135] Phase II Decision, ¶ 194.
[136] Public Service's RRR, pp. 15-16.
[137] Public Service's RRR, p. 16.

generating unit is unavailable for performance reasons, it should not be able to use curtailments to avoid the disincentives that would otherwise accrue under the operational PIM. Furthermore, with more robust load management capabilities, curtailments represent a valuable energy resource that could be used to serve load. In many cases, simply the fact of curtailments indicates shortcomings where the utility should strive to improve forecasting and the management of supply and demand resources. Ultimately, we grant Public Service's request on this point with the caveat that in follow on CPCN proceedings, the Commission may evaluate appropriate safeguards to ensure that curtailments are not used to mask poor operational performance potentially including a requirement to file availability data that can be easily cross-referenced with curtailments.

4. Additional PIMs

131. The Phase II Decision establishes a cost to construct PIM and an operational PIM for Company-owned generation projects arising from this Proceeding. While the cost to construct applies to all Company-owned generating projects regardless of the type, the operational PIM only applies to energy-based projects like wind and solar. The Phase II Decision excludes from the operational PIM capacity projects (like standalone storage and gas resources), noting that to do otherwise could have unintended consequences of incentivizing the overuse of dispatchable resources in order to avoid penalties or to accrue incentives.[138]

132. Staff asks the Commission to clarify that the Phase II Decision does not conclude that the cost to construct PIM is the only PIM that should be considered in the future for capacity projects. Staff notes that, like energy projects, capacity projects will incur ongoing operations and maintenance and capital costs and could experience performance issues that impact system costs and reliability. Staff therefore argues that it might be appropriate to develop a PIM that incentivizes

[138] Phase II Decision, ¶ 186.

the Company to meet the expectations for ongoing costs and performance that were assumed in the winning bids.[139]

133. The Commission grants Staff's request and clarifies that the cost to construct PIM is not the only PIM that can be considered in the future for capacity-based projects like storage and gas resources. Although the prior Phase II Decision was likely the best time to implement a new PIM, the Commission does not prohibit parties from raising PIM proposals in future CPCNs, especially since there will be more specific facts at that time to consider as applied to specific projects. We recognize that neither the cost to construct nor the operational PIM currently covers performance issues regarding capacity projects, yet performance issues from these projects can easily impact ratepayers. Future PIM proposals for capacity projects might involve a mechanism that better matches supply to demand, but will need to reflect the facts and circumstances that exist at that time.

5. Accelerated Cost Recovery

134. The Phase II Decision states: that all projects subject to the operational PIM "will receive cost recovery through the appropriate rider (RESA or ECA) from the ISD of the project until the project is rolled into base rates."[140]

135. Public Service asks the Commission to allow similar cost recovery treatment for projects that are covered by the cost to construct PIM such that "a project subject to any PIM, *i.e.*, the Cost to Construct PIM, the Operational PIM, or both PIMs, receive current cost recovery through the appropriate rider beginning on the ISD until it is rolled into base rates."[141] The Company argues that this approach treats Company-owned projects more similarly to IPP

[139] Staff's RRR, p. 3.
[140] Phase II Decision, ¶ 191.
[141] Public Service's RRR, p. 17.

projects and can help deter additional litigation and process on this topic in follow-on CPCN proceedings.[142]

136. The Commission grants Public Service's RRR on this point. We are persuaded by Public Service's arguments and see no reason to permit LEC projects to have accelerated cost recovery but not Levelized Cost of Capacity (LCC) projects.

6. Application of Operational PIM

137. Paragraph 186 in the Phase II Decision states: "Except for LCC-based projects like standalone storage and gas, the operational PIM will apply to all Company-owned generation arising from this Proceeding."[143] In the ordering paragraphs, the Phase II Decision states: "All Company-owned generation resources arising from the modified CEP are subject to both the cost to construct performance incentive mechanism (PIM) and the operational PIM, in accordance with the discussion above."[144]

138. In its RRR Application, Staff asserts that this is an inconsistency and recommends the Commission clarify that "the operational PIM only applies to Company-owned LEC projects."[145] Staff argues that this will help avoid future confusion.

139. We grant Staff's request and clarify that, in accordance with Paragraph 186 of the Phase II Decision, the operational PIM only applies to Company-owned LEC projects arising from this Proceeding.

[142] Public Service's RRR, p. 17.
[143] Phase II Decision, ¶ 186.
[144] Phase II Decision, p. 125.
[145] Staff's RRR, pp. 1-2.

7. Timeline for Operational PIM

140. Staff notes that when the Phase II Decision describes the evaluation timeline for the operational PIM, it does so in slightly different ways. Paragraph 189 describes the timeline as "a three-year rolling average after the third full operational year is complete and on a similar cadence thereafter." Paragraph 177 portrays the timeline as being one of "three-year intervals beginning with the first through third full calendar years of project operation." [146]

141. Staff asks the Commission to clarify this inconsistency. Staff states that because the Commission intended to adopt Public Service's suggestion, it should clarify that the phrase, "three-year rolling average," in Paragraph 189 should instead read, "three-year interval."[147]

142. The Commission grants Staff's RRR on this point and clarifies that the evaluation period for projects subject to the operational PIM will occur on three-year intervals. This is consistent with Public Service's suggestion in its Response Comments and the intent of the Phase II Decision.[148] While we grant Staff's request, we note that the ISDs and their interaction with any future timing PIM may be evaluated in future CPCN proceedings, which may have a bearing on the initial time interval under review.

8. Accelerated Cost Recovery Under CEP Rider

143. As referenced above, Paragraph 191 of the Phase II Decision states that all projects subject to the operational PIM in will receive cost recovery "through the appropriate rider (RESA or ECA)."[149]

[146] Staff's RRR, p. 2.
[147] Staff's RRR, p. 2.
[148] Public Service's Response Comments, p. 82.
[149] Phase II Decision, ¶ 191.

144. Staff asks that the Commission clarify that the CEP Rider (if approved) should also be on this list of appropriate riders. Staff reasons that—as determined in the upcoming CEP Rider advice letter proceeding—the CEP Rider might provide an additional pathway for cost recovery.[150]

145. We grant Staff's request and clarify that, along with the RESA and the ECA, the accelerated cost recovery that Paragraph 191 contemplates could also include the CEP Rider—depending on the outcome of the upcoming CEP Rider advice letter proceeding. For additional clarity and consistent with our rulings above, projects subject to either the operational PIM or the cost to construct PIM would be eligible for this accelerated cost recovery through the appropriate rider.

I. Transmission

1. MVLE and 2024 JTS

146. In Decision No. C22-0270 in Proceeding No. 21A-0096E (the Colorado Power Pathway CPCN), the Commission found that approval of a final resource plan in the 2021 ERP/CEP that includes the MVLE would demonstrate the need for the MVLE. Thus, the Commission granted Public Service a conditional CPCN for the MVLE that was contingent upon the MVLE being included in the approved resource plan in this Proceeding.[151]

147. In its RRR Application, Public Service states that "the most material difference" between the UPP and the Alternative Portfolio is that the Alternative Portfolio does not include the MVLE.[152] While Public Service does not advocate for the approval of the MVLE in this Proceeding, the Company requests that the Commission maintain the conditional CPCN for the MVLE as provided in Proceeding No. 21A-0096E through the 2024 JTS. Public Service argues

[150] Staff's RRR, pp. 3-4.
[151] Proceeding No. 21A-0096E, Decision No. C22-0270, issued June 2, 2022, ¶ 64.
[152] Public Service's RRR, p. 6.

that granting this request will allow certainty for bids connecting to the MVLE under the same conditions as in this Proceeding and will provide for the same mechanism to activate the CPCN if it is included in the approved portfolio.[153] The Company reiterates its view that the MVLE plays a key role in unlocking cost-effective and geographically diverse clean energy in the southeastern portion of Colorado.[154]

148. We grant Public Service's request and will maintain the conditional CPCN for the MVLE through the 2024 JTS. Consistent with what we contemplated in Proceeding 21A-0096E for the 2021 ERP/CEP, if the approved portfolio in the 2024 JTS includes the MVLE, the Company will receive a full CPCN for the MVLE. Given that the finding of need for the MVLE is inextricably linked to its cost, we direct the Company to present updated cost estimates for the MVLE in Phase I of the 2024 JTS. The proposed costs would be subject to litigation in Phase I and the final cost value would be used in modeling of any portfolio including MVLE-interconnecting bids in Phase II of the 2024 JTS.

2. ITA Scope of Work

149. The Phase II Decision directs Staff to initiate a stakeholder process to develop a scope of work for an independent transmission analyst (ITA). This stakeholder process will be "with UCA and CEO and in conferral with Public Service."[155]

150. Public Service seeks reconsideration of the stakeholder process to elevate the Company's status so that it is a stakeholder along with Staff, UCA, and CEO. Public Service argues that the process for determining a scope of work for the ITA, and identifying potential ITA candidates, should be a collaborative process where Staff, UCA, CEO, and the Company are all

[153] Public Service's RRR, pp. 6-7.
[154] Public Service's RRR, p. 6.
[155] Phase II Decision, ¶ 165.

"stakeholders."[156] The Company acknowledges that the ITA must maintain independence from Public Service, but argues that it should have more input than an after-the-fact conferral regarding the selection of the ITA and its scope of work.

151. In addition, the Company requests clear direction on how any ITA costs are recovered through existing adjustment clauses.[157]

152. The Commission grants Public Service's RRR request. Staff, UCA, CEO, and the Company are all stakeholders in the process to develop a scope of work for the hiring of an ITA. We reemphasize, however, our expectation set forth in the Phase II Decision that the ITA will work integrally with Staff and that the ITA must maintain independence from the Company. Although Public Service is a stakeholder in this process, the Company is not the sole or lead entity driving this process. The primary role of the ITA is building up the analytical capabilities of the parties, and particularly Staff, UCA, and CEO.[158]

153. As for cost recovery, we clarify that the Company will be able to seek timely recovery of all prudently incurred ITA costs through the transmission cost adjustment.

3. Denial of Transmission Investments

154. In Phase I of this Proceeding, the Company estimated a need for Denver Metro area transmission upgrades of approximately $250 million, but in the 120-Day Report the cost estimate for Denver Metro transmission upgrades had grown to approximately $2.2 billion. The Phase II Decision lists the large and unexpected transmission costs as one of many facts supporting the selection of the Alternative Portfolio.[159]

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[156] Public Service's RRR, p. 19.
[157] Public Service's RRR, p. 20.
[158] Phase II Decision, at ¶¶ 164-65.
[159] Phase II Decision, pp. 54-56.

155. In its RRR, the Company seeks clarification that the Commission is not affirmatively excluding any particular Denver Metro upgrade project in the Phase II Decision but instead simply expects supporting analysis establishing a need for such projects in future transmission CPCN proceedings.[160]

156. Consistent with Public Service's request, the Commission is not affirmatively rejecting any of the proposed transmission investments. It is our expectation, however, that Public Service will present a more holistic picture of the various transmission projects arising from this Proceeding, including an exploration of alternatives to the transmission investments and much more developed cost estimates. We further reiterate that (consistent with the Phase II Decision) the Denver Metro Transmission Upgrades are not part of the approved CEP.

4. Holistic Transmission Discussion

157. The Phase II Decision states that the Commission "needs to see a more holistic picture of the various transmission projects arising from this Proceeding" but leaves it to the Company's discretion on how best to present this type of analysis, both in timing and type of filings made.[161]

158. In its RRR, Staff argues that given the importance of the high-dollar transmission investments, Public Service should be required to file, within 30 days, an informational plan for developing and submitting the holistic information the Commission requests. Staff asserts that the Commission and parties will need to know this information as soon as possible because the Company will begin to file electric generation and transmission CPCNs later this year.[162]

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[160] Public Service's RRR, p. 21.
[161] Phase II Decision, ¶ 161.
[162] Staff's RRR, pp. 6-7.

159. The Commission grants Staff's request and required the Company to file an informational plan for how it will holistically present the various transmission projects arising from this Proceeding. To be clear, this does not impose a new requirement on Public Service to present the holistic picture of its transmission investments by a certain time or in a certain form. Rather, this simply requires the Company to make an informational filing describing the manner in which the Company plans to present the holistic picture. Public Service shall have 30 days within which to submit this informational filing in this Proceeding.

5. Regular RSC Reporting

160. In connection with its transmission-related request, COSSA/SEIA argues that, at the least, the Commission should require Public Service to regularly report on the Resource Solicitation Cluster (RSC) status for all selected bids. The first such report should be due within 30 days with subsequent reports issued on a quarterly basis thereafter.[163] COSSA/SEIA asserts that the Company has told winning bidders that its RSC process will take roughly two more years to complete and warns that such delays threaten the smooth implementation of the Alternative Portfolio.[164]

161. The Commission grants COSSA/SEIA's request. We see no issue with additional communication and transparency between the Company and the winning bidders regarding the RSC process. Public Service shall make file the RSC status reports in this Proceeding, consistent with COSSA/SEIA's request.

[163] COSSA/SEIA's RRR, p. 11.
[164] COSSA/SEIA's RRR, pp. 9-10.

J. Just Transition Solicitation

1. Scope of 2024 JTS

162. The Phase I Settlement contemplates, and the Phase I Decision approves, a process in which Public Service files a just transition plan for the Pueblo Unit 3 coal plant that includes a standalone competitive solicitation, or the JTS. While the focus of the 2024 JTS is the replacement of Unit 3 and the Pueblo community, the 2024 JTS is not geographically limited to the Pueblo area nor is the resource need limited to replacing Unit 3.[165] The Phase I Settlement Agreement fleshes out several procedural and substantive aspects the 2024 JTS but states that, to the extent not otherwise addressed, the 2024 JTS shall be treated as an interim ERP under Rule 3603(a).[166] The Phase II Decision contains several directives regarding this upcoming JTS, which Public Service will commence by June 1, 2024.

163. In rejecting arguments from CIEA and Interwest to use the 2024 JTS to rebalance the percentage of generation resources owned by the Company versus IPPs, Paragraph 297 of the Phase II Decision states that the "2024 JTS is an interim ERP that will largely be governed by the Commission's ERP rules."[167]

164. The Company seeks clarification that this statement is not designed to change or modify the numerous provisions in the Phase I Settlement Agreement setting forth the parameters and the scope for the 2024 JTS. Public Service is quick to acknowledge the Phase II Decision's directives and requests for information regarding the 2024 JTS and states that it is not seeking to alter any of those. The Company states that it simply wants to confirm that Paragraph 297 of the

[165] Phase II Decision, ¶ 52.
[166] Phase I Settlement Agreement, ¶ 43.
[167] Phase II Decision, ¶ 297.

Phase II Decision is not intended to modify Phase I Settlement or to require that the full set of ERP provisions required in the Commission's Rules apply to the 2024 JTS.[168]

165. The Commission grants this narrow clarification and confirms that Paragraph 297 of the Phase II Decision does not modify the Phase I Settlement Agreement in any way. The Phase I Settlement specifies that the 2024 JTS "shall be treated as an Interim ERP under Rule 3603(a) and shall otherwise comply with applicable ERP Rules for the first and second phases of the process" to the extent that any procedures or aspects of the 2024 JTS are not otherwise addressed in the Phase I Settlement.[169] Paragraph 297 of the Phase II Decision does not alter these provisions in the Phase I Settlement Agreement.

2. Non-Price Factor Bid Evaluation

166. In its RRR Application, WRA requests that the Commission direct the Company to propose a more transparent non-price factor bid evaluation process as part of its Phase I filing in the 2024 JTS. WRA argues that the Company does not explain how it compared and weighed non-economic factors or how each qualitative factor impacted the decision to eliminate a bid or progress it to computer-based modeling during the Phase II modeling process. Similarly, WRA notes the Commission's concern that the Company failed to notify bidders of any geographically targeted need for generation resources. WRA characterizes this as a qualitative factor that could have been evaluated in the non-price bid evaluation stage.[170]

167. WRA made a similar recommendation in its Phase II Comments. In its Response Comments, Public Service briefly acknowledged WRA's suggestion but argued that the

[168] Public Service's RRR, p. 23.
[169] Phase I Settlement, ¶ 43.
[170] WRA's RRR, pp. 7-8.

Commission can address the suggestion as part of a robust Phase I process in the 2024 JTS and the 2026 ERP.[171]

168. The Commission grants WRA's RRR on this point and directs Public Service to propose a transparent non-price factor bid evaluation process as part of its Phase I filing in the 2024 JTS. As WRA references in its RRR, non-price factors had significant impacts on the results of Phase II modeling, especially regarding the Company's determination that certain geographic areas had strategic locational benefits (*e.g.* the Alamosa area and within the Denver Metro area). In the Phase II Decision, we expressed our disappointment that "specific, locational reliability concerns were not clearly communicated in Phase I, which could have been informative to potential bidders and provided additional options."[172] Going forward, we certainly expect improvements in the 2024 JTS to ensure both a fair and transparent bidding process and cost-effective results. While the Commission refrains from deciding at this juncture how non-price factors will be evaluated in Phase II of the 2024 JTS, it is appropriate to require Public Service to consider non-price factors that might impact resource selection in the 2024 JTS and include as part of its Phase I filing a more transparent evaluation process.

3. Sequential Bid Solicitation

169. WRA requests that the Commission direct Public Service to bring forward a proposal to establish a schedule of sequential, rolling solicitations for a progression of years, and conduct a progression of RFPs. WRA cites the Independent Evaluator's Report that advocates for a similar recommendation for sequential bid solicitations, noting the magnitude of issues in this Proceeding as proof that the Commission's ERP process would benefit from refinement.

[171] Public Service's Response Comments, pp. 111-12.
[172] Phase II Decision, ¶ 124.

WRA states that the Commission's directive on this issue need not be overly prescriptive but that providing guidance prior to the Phase I decision in the 2024 JTS will allow for a more comprehensive proposal, especially to the extent that sequential solicitations interact with the identified resource need to be filled in the 2024 JTS.[173]

170. The Commission rejects WRA's proposal. Rule 3603 directs utilities to file ERPs every four years but notes a utility may file an interim plan more frequently than the required four-year cycle. We acknowledge that our ERP processes are constantly developing, and the concept of sequential bid solicitations may have merit. While we will stop short of requiring Public Service to bring forward a specific proposal as part of the 2024 JTS filing, we hope to continue evaluating this and other process updates in the 2024 JTS.

4. Rebidding into the 2024 JTS

171. WRA recommends the Commission direct Public Service to permit bids that were not selected in the 2021 ERP to re-bid and refresh their bid pricing in the 2024 JTS, for a smaller bid fee or without paying another bid fee entirely. Alternatively, WRA asks that the Company be required to present a proposal in the 2024 JTS that allows for either reduced bid fees or repeat bids.[174]

172. The Commission rejects WRA's request. We will not decide, at this juncture, the appropriate bid fees in the 2024 JTS. This issue would benefit from a more robust record developed in Phase I of the 2024 JTS. We thus deny WRA's main request as well as its alternative request to require Public Service to propose a reduced or eliminated bid fee. Parties to the

[173] WRA's RRR, pp. 8-9.
[174] WRA's RRR, p. 9.

upcoming 2024 JTS are encouraged, as always, to raise their respective positions on these and other areas of adjudication.

5. Gas Resource Bidding and Modeling Constraints

173. WRA asks the Commission to direct Public Service in future ERPs to more creatively pursue short-term extensions of existing gas PPAs. WRA notes that both the Alternative Portfolio and the UPP rely on the construction of new gas and did not select any existing gas units. WRA argues that selecting only a new-build PPA gas resource and the paucity of existing gas PPAs is a dilemma because it is unclear what remedies are available if it is subsequently determined that clean resources can contribute to system reliability without producing emissions.[175]

174. WRA similarly notes that in the Phase II Decision the Commission states an expectation that prior to the 2024 JTS the Company will strive to resolve modeling issues such as the reliability rubric, the lack of notification to bidders about the strategic locational value of certain gas resources, and parties' concerns about new gas resources generally. WRA respectfully requests that the Commission clarify that this expectation applies to the contents of the Company's Phase I filing for the 2024 JTS. [176]

175. The Commission grants, in part, and denies, in part, WRA's request. We share WRA's concern regarding increased optionality regarding new-build versus existing gas resources. Indeed, this issue was a central feature of the Phase I adjudication in this Proceeding and gave rise to guardrails such as the 25-year modeling restriction for new-build gas units. In addition, we urged Public Service to be flexible in applying requirements such as remote start capability, fast start capability, and fuel flexibility to existing gas units. The Phase I Decision requests that the

[175] WRA's RRR, pp. 10-11.
[176] WRA's RRR, p. 11.

Company use "good judgment when it evaluates the rebid of existing gas units to enable the continued use of these units over the construction of new units wherever possible."[177] Given the reliability concerns Public Service has raised with relying on short-term extensions of existing gas units, however, it is unclear how the Company would comply with a directive to "creatively pursue short-term extensions of existing gas PPAs." Thus, we refrain from issuing such a directive here but emphasize that we nevertheless expect to see a robust consideration of using short-term extensions of existing gas PPAs in the Phase I of the 2024 JTS, especially as we continue to move closer to Colorado's goal for 100 percent clean energy.

176. Conversely, the Commission agrees with WRA's related request and clarify that the Company must address in its Phase I filing in the 2024 JTS how it intends to resolve modeling issues such as the reliability rubric and the transparency regarding the strategic locational value of certain gas resources. These modeling issues were major issues in the Phase II process in this Proceeding, and the Company needs to fully address these issues in its Phase I filing in the 2024 JTS.

6. JTS Phase I Modeling and Portfolio Analysis Processes

177. COSSA/SEIA argues the Commission should order that key Company modeling frameworks be fully litigated in Phase I. Noting how the Phase II Decision requires the Company to confer with Staff and other interested parties prior to the 2024 JTS to develop more robust modeling processes regarding things like best-in-class modeling, the reliability rubric, and meaningful demand side resources options, COSSA/SEIA asserts that the Commission should go a step further and "ensure that the Company's decisions are thoroughly and formally vetted by

[177] Phase I Decision, ¶ 281.

ordering that Company decisions on approaches to modeling are fully litigated in Phase I of future planning proceedings."[178]

178. The Commission grants COSSA/SEIA's request in part and clarifies that, consistent with Rule 3617(c)[179] and the Phase I Settlement, key modeling frameworks will be litigated in Phase I of the 2024 JTS. For example, and consistent with our directives above, we fully expect that issues such as the best-in-class modeling, the reliability rubric, and meaningful demand side resources options will be adjudicated during Phase I of the 2024 JTS. We reaffirm, however, our finding in the Phase II Decision that "it would be premature on this Phase II record to specify how the next ERP process will resolve these modelling and process issues,"[180] and will refrain from using this Phase II Decision addressing RRR Applications to modify the Company's discretion in Phase II of the 2024 JTS.

7. Requiring Portfolios to Meet Minimum Reliability Requirements

179. Conservation Coalition asks the Commission to direct Public Service in the 2024 JTS to ensure that all portfolios the Company presents in modeling meet minimum reliability requirements. As support, Conservation Coalition argues that in this Proceeding the Company used reliability requirements to claim that the Preferred Portfolio and the Inverse 1324 Portfolio (a version of the Preferred Portfolio) were the only reliable Phase II portfolios.[181] Conservation Coalition states that the Company announced locational reliability requirements for the first time in the 120-Day Report but deliberately constructed only its Preferred Portfolio and

[178] COSSA/SEIA's RRR, pp. 12-13 (citing Phase II Decision, 286-87).

[179] Among other things, Rule 3617(c) specifies that in the Commission's Phase I decision, the Commission shall approve or modify the utility's plans for acquiring additional resources through a solicitation, the proposed evaluation criteria, and the alternate scenarios for assessing the costs and benefits from the potential acquisition of resources.

[180] Phase II Decision, ¶ 287.

[181] Conservation Coalition's RRR, p. 32.

related versions of the Preferred Portfolio to meet these new reliability requirements. Conservation Coalition asserts that because the Commission accepted the Company's statements regarding reliability, the construction and review of all of the other Phase II portfolios was "a huge waste of the Company's, the parties', and the Commission's time."[182]

180. Relatedly, Conservation Coalition asks that the Commission revise its Phase II Decision to specify that in the 2024 JTS "the Company should not use any reliability metrics and/or methodologies in Phase II unless they have been previously approved by the Commission either in its Phase I order or a subsequent order; and instruct the Company that the Commission will not tolerate the Company deviating from the modeling methodology and assumptions approved in a Phase I Order unless the Company has obtained prior approval from the Commission." [183]

181. The Commission denies Conservation Coalition's request, in part. Conservation Coalition raises valid concerns with the Company's construction of Phase II portfolios that the Company later deemed unreliable. Again, however, we reaffirm that it would be premature on this Phase II record to specify how the next ERP process will resolve modelling and process issues.[184] To ensure that there is a robust record on this issue in Phase I of the 2024 JTS, we direct Public Service to explain in its Phase I filing its position on whether all Phase II portfolios should meet minimum reliability requirements. It is our expectation that Public Service will address improvements to the process so that we avoid wasting time evaluating portfolios that the Company argues it cannot consider reliable.

182. Regarding Conservation Coalition's related request to prohibit the use of reliability metrics or methodologies in Phase II of the 2024 JTS that were not approved in Phase I, we

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[182] Conservation Coalition's RRR, pp. 32-33.
[183] Conservation Coalition's RRR, p. 33.
[184] Phase II Decision, ¶ 287.

similarly see merit to this proposal, but this directive is more appropriate in the Phase I decision in the 2024 JTS. Thus, we simply direct the Company to explain its position on Conservation Coalition's request in its Phase I filing in the 2024 JTS.

K. Depreciation of Gas Resources

183. CEO maintains its recommendation from its Phase II Comments that the Commission direct that Company-owned gas units arising from this Proceeding must depreciate consistent with the 25-year life used for Phase II modeling purposes. CEO argues that such a directive would be consistent with the Phase II modeling, numerous cost considerations regarding the gas units, and state climate and clean energy policies.[185]

184. CEO asserts that the "full cost of any Company-owned asset is greatly affected by the depreciation schedule approved by the Commission" and reiterates its argument set forth in its Phase II Comments that the depreciation schedule for approved gas resources must align with the State's 2050 goal of net zero emission.[186] CEO observes that the Phase II Decision does not establish a depreciation schedule for Company-owned gas units nor a timeline for the filing of depreciation study.[187]

185. In the alternative, CEO argues that if the Commission declines to set the depreciable life here, then the Commission should (1) order Public Service to file a depreciation study within 60 days and (2) establish when the Commission will decide on an appropriate depreciation schedule for these resources.[188] CEO further asks that the Commission require the Company to include in the depreciation study the following schedules: (1) a 25-year depreciation schedule as

[185] CEO's RRR, pp. 6-7.
[186] CEO's RRR, pp. 5-6.
[187] CEO's RRR, p. 6.
[188] CEO's RRR, pp. 7-8.

modeled in the 120-Day Report; (2) full depreciation by January 1, 2050; and (3) any additional schedules as determined by the Commission and the Company.[189]

186. We generally agree with the notion expressed by CEO that depreciation of gas unit assets should align with state policy timelines and emission reduction goals. However, this Phase II process is not the appropriate venue to affirm depreciation timelines and cost recovery in line with the 25-year modeled life. As noted throughout this Decision and our Phase II Decision, resource modeling in this Proceeding is expressly tied to best understanding our ERP and CEP goals and directives. Explicit findings and considerations of cost recovery, including appropriate depreciation of assets, is best litigated on a more targeted and robust record with actual numbers, such that we can address customer bill impacts and the affordability of electricity for customers, while reaching state emission reduction targets. Particularly where it is unclear if all of these gas assets will be pursued, and where many are not scheduled to be online for a number of years, depreciation and related bill impacts are best addressed in the context of rate case considerations or through separate, future filings.

187. The Commission therefore denies CEO's request to set a depreciation schedule through this Proceeding. We do find merit, however, in CEO's alternate request to provide a future depreciation study. As discussed throughout this Decision, upcoming proceedings will include further detailed consideration of rate impacts resulting from the implementation of this ERP. Therefore, we find it appropriate to require the Company to address depreciation of utility owned gas units included in the Alternative Portfolio and any backup bid processes in follow-on CPCN proceedings. CPCN proceedings will better address unit considerations as the Company moves forward with specific projects associated with the modified CEP. Examining depreciation in the

[189] CEO's RRR, p. 7.

CPCN process will allow the Commission better timing and considerations of cost impacts prior to customer billing, including with regard to any potential recovery in an associated rider.

188. In addition, we remain interested in the issue of better aligning depreciation of these or other units, including beyond the future CPCN processes. It is our expectation that the Company will be forthcoming with operational planning, including corresponding depreciation studies and proposed schedules, in the Company's next electric rate filings.

189. The Commission therefore grants, in part, and denies, in part CEO's RRR request. Prior to actual cost recovery for the gas unit assets, the Commission requires a review of robust filings regarding depreciation schedules and revenue requirement analysis, such that it can consider fully appropriate rate impacts to customers. Considerations of depreciation for the gas units should consider not just engineering life, but also the likely useful policy life and intent to minimize stranded asset risk for customers. Accordingly, Public Service shall include a robust analysis of depreciation rates and expenses in follow-on CPCN proceedings regarding any company-owned gas units that move forward.

L. Load Management Potential Study

190. WRA recommends the Commission explicitly direct the Company to provide an analysis of load management potential in its revised Demand Side Management (DSM) potential study to be filed as part of the Company's next DSM Strategic Issues filing in 2025. WRA notes that it shares the Commission's desire for more robust use of demand-side resources and argues that ordering such a study in the 2024 JTS or the upcoming 2025 Strategic Issues proceeding would be too late.[190]

[190] WRA's RRR, pp. 4-5.

191. WRA made this same recommendation in its Phase II Comments, and Public Service did not oppose the recommendation in its Response Comments: "The Company does not oppose WRA's recommendation and believes such a load management potential analysis would complement the other DSM potential study requirements regarding energy efficiency and beneficial electrification outlined in the Commission's Decision in Proceeding No. 22A-0309EG (Decision No. C23-0413)."[191]

192. The Commission grants WRA's RRR request on this point and directs Public Service to include an analysis of load management potential in its revised DSM potential study to be filed as part of the Company's next DSM Strategic Issues filing in 2025. This request is unopposed and aligns with the Commission's findings in the Phase II Decision: "[we] again urge the Company to come forward in future proceedings, including the 2024 JTS, with more developed demand side resources and other reliability solutions that do not involve new gas resources."[192] This directive also aligns with our directives in Proceeding No. 22A-0309EG.

II. <u>ORDER</u>

A. The Commission Orders That:

1. The Application for Rehearing, Reargument, or Reconsideration of Decision No. C24-0052 filed by Public Service Company of Colorado (Public Service) on February 12, 2024, is granted, in part, denied, in part consistent with the discussion above.

2. The Application for Rehearing, Reargument, or Reconsideration filed by Staff of the Colorado Public Utilities Commission on February 12, 2024, is granted, in part, denied, in part, consistent with the discussion above.

[191] Public Service's Response Comments, p. 109.
[192] Phase II Decision, ¶ 124.

3. The Application for Rehearing, Reargument, or Reconsideration filed by the Utility Consume Advocates on February 12, 2024, is denied consistent with the discussion above.

4. The Application for Rehearing, Reargument, or Reconsideration filed by the Colorado Energy Office on February 12, 2024, is granted, in part, denied, in part, consistent with the discussion above.

5. The Application for Rehearing, Reargument, or Reconsideration filed by Colorado Solar and Storage Association and Solar Energy Industries Association on February 12, 2024, is granted, in part, denied, in part, consistent with the discussion above.

6. The Application for Rehearing, Reargument, or Reconsideration filed by Western Resource Advocates on February 12, 2024, is granted, in part, denied, in part, consistent with the discussion above.

7. The Application for Rehearing, Reargument, or Reconsideration Natural Resources Defense Counsil and Sierra Club on February 12, 2024, is granted, in part, denied, in part, consistent with the discussion above.

8. The Motion for Leave to File a Response filed by Public Service on February 26, 2024, is granted.

9. The 20-day time period provided by § 40-6-114, C.R.S., to file an application for rehearing, reargument, or reconsideration shall begin on the first day after the effective date of this Decision.

10. This Decision is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING March 6, 2024.

(S E A L)

STATE OF COLORADO ★ THE PUBLIC UTILITIES COMMISSION ★ NIL SINE NUMINE

ATTEST: A TRUE COPY

Rebecca E. White

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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Commissioners