Decision No. C25-0024

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 GRANTING, IN PART, AND DENYING, IN PART, THE MOTION TO APPROVE THE CLEAN ENERGY PLAN DELIVERY PLAN

Issued Date: January 14, 2025
Adopted Date: December 16, 2024 and December 20, 2024

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I. BY THE COMMISSION

A. Statement

1. On September 6, 2024, Public Service Company of Colorado ("Public Service" or the "Company") filed a Motion to Approve Clean Energy Plan ("CEP") Delivery Plan and for Variances from Certain Commission Rules and Decisions ("CEP Delivery Motion").

2. Through this Decision, the Commission grants, in part, and denies, in part the CEP Delivery Motion. Our Decision allows the generation and storage projects included within the CEP to continue advancing despite changing market dynamics and geopolitical uncertainties, including importantly potential future changes in federal law. Advancing these generation and storage projects as part of the overall determinations made through the course of this Proceeding moves Colorado forward towards achieving aggressive state emission reduction targets. At the same time, while some amount of price flexibility is necessary, particularly given reliability and emission reduction considerations, our Decision also balances this price flexibility with several protections to ensure the CEP comes at a reasonable cost to customers. These protections include a two-stage process for clean energy projects that caps the amount of price relief and permits intervenor and Commission review as well as using existing regulatory processes for additional investigation and review of price increases associated with utility-owned projects. Similarly, this Decision finds that the record and abbreviated process associated with the CEP Delivery Motion are insufficient to make certain requested findings regarding additional thermal capacity and proposals to modify a demand responses ("DR") program. As set forth below, the Company is in no way prohibited from making appropriate filings to move these or other endeavors forward, particularly as it ensures reliability.

3. These determinations provide a process in consideration of the CEP Delivery Motion enabling timely review should federal changes in law arise that impact bid pricing, concurrent with guidance towards longstanding Commission processes. This careful balance and necessary flexibility to move towards significant emission reduction targets, while protecting Colorado ratepayers, including by allowing ongoing scrutiny, particularly of utility-owned projects not yet demonstrated as warranting a presumption of prudence.

B. Procedural History

4. Public Service initiated this Proceeding by filing its Verified Application for Approval of its 2021 Electric Resource Plan ("ERP") and CEP on March 31, 2021.

5. On August 3, 2022, the Commission issued Decision No. C22-0459 ("Phase I Decision"). Among other things, the Phase I Decision authorized Public Service to implement a competitive bidding process for acquiring cost-effective resources to meet its projected resource need from 2022 through 2028. The Commission also approved the process for evaluating bids to the competitive solicitation and established the modeling parameters, including inputs and assumptions, for the presentation and consideration of potential resource portfolios in Phase II of the Commission's ERP process. Pursuant to the terms of the Updated Non-unanimous Partial Settlement Agreement approved, in part, by the Phase I Decision, the Commission further authorized Public Service to initiate an interim ERP called the Just Transition Solicitation ("JTS") focused on meeting the projected resource need for the years 2029, 2030, and 2031.[1]

6. On January 23, 2024, the Commission issued Decision No. C24-0052 ("Phase II Decision"), approving the Company's CEP with modifications. Among other things, the Phase II

[1] Public Service filed an Application for Approval of its Just Transition Solicitation on October 15, 2024 in Proceeding No. 24A-0442E ("JTS Proceeding"). The JTS Proceeding is ongoing.

Decision authorized Public Service to pursue the acquisition of more than 5,800 MW of new storage and generation projects that were included in the approved resource portfolio with further due diligence and contract negotiations.[2] The approved resource portfolio includes 669 MW of thermal resources, consisting of four separate projects: Bid 0989 (a 200 MW Company-owned unit), Bid 0997 (a 200 MW Company-owned unit), Bid 0011 (a 50 MW unit that would be developed and constructed by a third-party but ultimately owned by the Company), and Bid 0235 (a 219 MW power purchase agreement ("PPA") unit). The Commission found that the inclusion of the PPA thermal resource (Bid 0235) was attractive in that it reduces the risk that customers will bear future costs associated with utility-owned gas resources, including the risks that utility-owned gas resources will become stranded.[3]

7. The Phase II Decision also established a cost-to-construct ("CtC") performance incentive mechanism ("PIM") for each utility owned generation and storage project in the approved resource portfolio. In the Phase II Decision, the Commission recounted how in other contexts, costs, performance, or scheduling issues have increased the costs of utility-owned projects relative to the initial estimates the Company provided.[4] The Commission opined that material changes to the cost and performance metrics of a project could impact the justification of the ERP need determinations. In addition, with competitive solicitation being the lynchpin of Colorado's ERP process, we opined that winning bidders should not be able to materially increase the price of bids without consequences.[5] To incentivize Public Service to build utility-owned projects at or below budget, the Commission established the CtC PIM that used the as-bid capital

[2] Phase II Decision, ¶ 92.

[3] Phase II Decision, ¶¶ 101 108.

[4] The Commission gave the specific example of the Company's representations in Phase I of the proceeding that the conversion of the Brush Coal Plant to burn gas would cost approximately $44 million. In the subsequent CPCN application, however, the Company's estimated costs had increased to $85 million. (Phase II Decision, ¶ 180).

[5] Phase II Decision, p. 125.

construction cost for each project as the baseline, set a five percent deadband around the baseline, and then set three symmetric tiers of costs sharing if the actual construction costs for a project were above or below the deadband.[6]

8. In the Phase II Decision, the Commission directed Public Service to file applications for Certificates of Public Convenience and Necessity ("CPCN") for all utility-owned resources within the approved resource portfolio. The Commission noted that, consistent with 4 *Code of Colorado Regulations* ("CCR") 723-3-3617(d) of the Commission's Rules Regulating Electric Utilities, Public Service's actions that are consistent with the Phase II Decision have a presumption of prudence.[7]

9. On March 13, 2024, the Commission issued Decision No. C23-0672 Addressing Applications for Rehearing, Reargument, or Reconsideration ("RRR") of the Phase II Decision ("First RRR Decision"). The First RRR Decision addressed several issues, including challenges to the approved resource portfolio, proposed modifications to the established CtC PIM, and the appropriate process for selecting backup projects. In addition, the First RRR Decision addressed the replacement of Bid 0235, which became unavailable after the Phase II Decision. The Commission specifically rejected the Company's request to replace Bid 0235 (a PPA project) with Bid 1000 (a utility-owned project). The Commission reiterated that diversifying the ownership of the gas resources can help reduce risks to ratepayers and expressed a strong interest in evaluating whether there were other PPA gas resources that could replace Bid 0235, such as Bid 0510, Bid 0514, and Bid 1061.[8]

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[6] Phase II Decision, ¶¶ 183-185.
[7] Phase II Decision, p. 125.
[8] First RRR Decision, pp. 34-35.

10. On September 6, 2024, Public Service filed the CEP Delivery Motion, along with the testimony of Jack Ihle and several attachments. Among other things, the CEP Delivery Motion puts forth a proposed procedural schedule and limited discovery rights to facilitate the Commission's review of the Motion.

11. On September 10, 2024, Climax Molybdenum Company ("Climax") filed a Response to Public Service's proposed procedural schedule, which the Office of Utility Consumer Advocate ("UCA") and the Colorado Energy Consumers ("CEC") join. In the Response, Climax acknowledges the urgency of the CEP Delivery Plan but argues for extending the deadline for intervenor responses and increasing the amount of discovery that parties can propound. In its Response, Climax further states it prefers to proceed with an evidentiary hearing.

12. On September 19, 2024, the Commission issued Decision No. C24-0678-I. Among other things, Decision No. C24-0678-I set a procedural schedule that required the Company to file supplemental information, followed by intervenor responses, and a reply from Public Service to those responses ("Reply Comments"). Decision No. C24-0678-I also established limited discovery rights and scheduled a two-day *en banc* evidentiary hearing. The procedural schedule and discovery limits were a compromise approach that balanced the need for expediency and the concerns that certain intervenors raised regarding the deadline for intervenor responses and the amount of discovery rights afforded.[9]

13. By Decision No. C24-0699-I,[10] the Commission addressed both UCA's request to shorten the timeline for Public Service to respond to discovery and certain recommendations regarding Plains End (an existing PPA thermal resource). In addition, we invited the parties to

[9] Specifically, the concerns set forth in Climax's Response to Public Service's proposed procedural schedule. As set forth above, Climax argued for extending the deadline for intervenor responses and increasing the amount of discovery. UCA and CEC joined Climax's Response.

[10] Issued September 26, 2024.

comment on a proposed approach to maintain competitive tension and directed Public Service to provide additional information regarding certain wind and thermal bids.

14. On October 4, 2024, Public Service filed supplemental comments and information, pursuant to Decision No. C24-0678-I. Included in this supplemental filing was Hearing Exhibit 166, Attachment JWI-17. This Attachment is a detailed report on the status of all bids and includes information from the bidders regarding whether they are able to move forward with their as-bid pricing and the scope of price relief many bidders assert they need to move forward with their projects. Public Service submitted a revised version of this Attachment on November 1, 2024.

15. On October 11, 2024, the following intervenors filed Answer Testimony to the CEP Delivery Motion: Staff, the Colorado Energy Office ("CEO"), UCA, and the Colorado Solar and Storage Association and the Solar Energy Industries Association ("COSSA/SEIA"). In addition, the following parties filed Comments on the CEP Delivery Motion: the Colorado Independent Energy Association ("CIEA"), Interwest Energy Alliance ("Interwest"), Western Resource Advocates ("WRA"), and CEC.[11]

16. On October 3, 2024, Mainspring Energy, Inc. ("Mainspring"), filed an unopposed motion to intervene out of time in this Proceeding ("Late Intervention"). Mainspring is the developer of Bid 0011, which is a 50 MW new-build thermal resource in the San Luis Valley. Mainspring has been negotiating a build-transfer agreement with Public Service in which the Company will ultimately own and operate Bid 0011. In its Late Intervention, Mainspring argues the CEP Delivery Motion could directly and substantially impact Mainspring.

[11] Climax as well as UCA support and join in CEC's comments.

17. By Decision No. C24-0736-I,[12] the Commission granted Mainspring's Late Intervention. The Commission found that Mainspring sufficiently demonstrated its interests in this Proceeding and noted that no party opposes the Late Intervention.

18. On October 11, 2024, Mainspring filed Answer Testimony from two witnesses.

19. In Decision No. C24-0746-I,[13] the Commission directed Public Service to provide additional information in its Reply Comments. The Commission required the Company's Reply Comments to include the relevant PPA and build transfer agreement provisions that would implement a change-in-law price relief mechanism as well as examples of the PPA provisions that allegedly pose an unacceptable level of risk to the Company.

20. On October 25, 2024, Public Service submitted its Reply Comments.

21. On November 1, 2024, Mainspring filed an unopposed motion requesting access to certain confidential and highly confidential information pertaining to Bid 0011 ("Unopposed Motion to Access Information").

22. By Decision No. C24-0805-I,[14] the Commission granted Mainspring's Unopposed Motion to Access Information.

23. On November 7, 2024, the Commission held a remote evidentiary hearing at which the following exhibits and associated attachments were admitted: Hearing Exhibits 166, 509, 1205, 2202, 2204, 2709, 2710, 2711, 2712, 2713, 2714, 2715, 2716, 2717, 2718, 2719, 2720, 2721, 2722, 2723, 2725, 2904, 3000, and 3001.

24. On November 18, 2024, the following parties filed statements of position ("SOPs"): Public Service, Staff, UCA, CEC,[15] CIEA, COSSA/SEIA, Interwest, Mainspring, and WRA.

[12] Issued October 11, 2024.
[13] Issued October 16, 2024.
[14] Issued November 6, 2024.
[15] Climax supports and joins CEC's SOP.

25. The Commission deliberated on the CEP Delivery Motion at the December 16, 2024 Commissioner's Deliberations Meeting ("CDM") and the December 20, 2024 CDM.[16]

C. Background of the CEP Delivery Motion

26. In the CEP Delivery Motion, Public Service argues that global and national geopolitical and market forces require some adjustments to the CEP to ensure the generation and storage projects contemplated in the approved resource portfolio can move forward.[17] Public Service categorizes its requests into three components. Component 1 consists of a two-stage process in which renewable energy and storage projects could request price relief.[18] Under this process as initially proposed, developers (including the Company) could individually submit requests to a newly appointed Independent Auditor ("IA") to increase the price of their projects based on things such as unexpected supply chain difficulties, recent changes in tariff policy, or future changes in federal law. The IA would then verify whether the requested price increase is justified and submit its verification decision to the Commission for review.[19]

27. Under Stage 1 of this first component, developers could base price increase requests on a broad set of circumstances such as known and pending tariffs or duties, supply chain issues, or any other impacts of current market conditions such as changes in costs of materials or labor.[20] As proposed in the CEP Delivery Motion, developers could receive Stage 1 price relief of up to six percent increase of the as-bid pricing. Under Stage 2 of Component 1, developers could submit price increase requests to the IA based on a specified changes in federal law such as new tariffs or

[16] The procedural history and background of this case are more fully set forth in the Phase II Decision and the First RRR Decision. Here, we provide only that background and procedural history necessary for this Decision.
[17] CEP Delivery Motion, p. 2.
[18] Hr. Ex. 166 (Ihle), p. 35.
[19] Hr. Ex. 166 (Ihle), pp. 40-41.
[20] Hr. Ex. 166 (Ihle), pp. 35-36.

the reduction or repeal of the currently available production tax credits ("PTCs") or investment tax credits ("ITCs").[21] Developers could receive additional price relief in Stage 2 up to a total of 15 percent, inclusive of any Stage 1 relief. Thus, if a project received a six percent price relief in Stage 1, it would only be eligible for up to an additional nine percent increase in Stage 2.[22]

28. Component 2 addresses the thermal resources contemplated in the approved resource portfolio. Similar to the renewable energy and storage projects in Component 1, Public Service argues that the thermal resources need price increases to address disruptions to supply chains, strong demand for thermal unit components and labor, and the length of time that has elapsed since the bids were initially submitted on March 1, 2023.[23] Public Service seeks the ERP presumption of prudence per Rule 3617(d) that moving forward with the thermal units at the new revised cost levels is prudent. In addition, Public Service asks that the CtC baseline for the utility-owned gas facilities be adjusted upward to match the new cost estimates.[24]

29. Component 2 includes the Company's request for Commission approval to replace Bid 0235 with Bid 1000. Bid 0235 (a 219 MW new-build PPA gas resource) was included in the approved resource portfolio but is no longer available. The Company also seeks authorization to not include the selective catalytic reduction ("SCR") system that it originally planned for Bid 0989 (a 200 MW, utility-owned gas unit).[25]

30. As an alternative to Components 1 and 2, Public Service suggests the Commission treat utility-owned projects as "a distinct portfolio." Under this alternative, the projects in the utility-owned portfolio would keep the same construction costs that the Phase II Decision

[21] Hr. Ex. 166 (Ihle), p. 52.
[22] Hr. Ex. 166 (Ihle), p. 51.
[23] Hr. Ex. 166 (Ihle), p. 57.
[24] Hr. Ex. 166 (Ihle), pp. 57-58.
[25] Hr. Ex. 166 (Ihle), pp. 88-89.

contemplates, but instead of several project-specific PIMs, there would be one portfolio-wide PIM with a five percent deadband.[26] PPA projects could continue to seek price relief under the proposed Component 1 process.[27]

31. In Component 3, the Company requests approval to take certain actions to address near-term resource adequacy concerns by increasing capacity. Specifically, the Company requests a PPA extension for Plains End (a 219 MW unit with a PPA that expires at the end of 2027)[28] and increasing the incentives in the interruptible service option credit ("ISOC") program in an attempt to boost DR capacity.[29] Initially, Public Service also requested as part of Component 3 an extension of Bid 1061 (a 76 MW PPA thermal resource).[30] However, Bid 1061 subsequently became unavailable.[31]

D. Component 1, Stage 1

1. Party Positions

32. As initially presented, in Stage 1 of Component 1, both utility-owned and PPA clean energy resources could obtain price increases of up to six percent due to current market conditions. To receive such pricing relief, developers would submit requests and supporting information to the IA, and the IA would make a project-specific determination of whether the price increase is legitimate reasonable or whether it was due to an unreasonably low bid estimate. In their SOPs, however, several parties, including Public Service, Staff, CIEA, and COSSA/SEIA argue the Commission should fundamentally modify the proposed Component 1, Stage 1 process by eliminating the IA review process.

[26] CEP Delivery Motion, pp. 2-3.
[27] Hr. Ex. 166 (Ihle), p. 90.
[28] Hr. Ex. 166 (Ihle), p. 114.
[29] Hr. Ex. 166 (Ihle), p. 101.
[30] Hr. Ex. 166 (Ihle), pp. 112-13.
[31] Hr. Ex. 166 (Attachment JWI-16), p. 20.

33. Public Service specifically recommends that the Commission apply a uniform one to three percent price increase, without further IA reviews. Public Service "suggests 2 percent but defers to the independent power producer ("IPP") trade associations on the specific level of relief."[32] For wind projects, Public Service recommends the Commission apply a six percent price increase.[33] PPA projects would receive the approved price increase if the bidder can provide an affidavit of a corporate officer for the IPP bidder supporting the causes of the price increase. Any project that takes a Stage 1 increase would remain eligible for a Stage 2 change-of-law adjustment, and no increase could exceed 15 percent in aggregate, as initially proposed in the CEP Delivery Plan.[34]

34. For utility-owned clean energy projects, Public Service "would provide sworn testimony in support of the increase to the CtC value in the CPCN proceeding…."[35] The individual PIMs would be built around this updated CtC value and the CtC baseline would be entitled to a presumption of prudence in the follow-on CPCN proceeding.[36] For the three utility-owned wind projects in particular, Public Service makes clear in its SOP that the Company's sworn testimony in the CPCN proceeding would support an increase in the CtC value, "which may not exceed 6 percent."[37] Consistent with its initial proposal, Public Service argues that the price increases should be based on the $/MWh or $/kW-month PPA rates for IPP projects and should be based on the construction costs for utility-owned projects.[38]

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[32] Public Service's SOP, p. 2.
[33] Public Service's SOP, p. 2.
[34] Public Service's SOP, p. 8.
[35] Public Service's SOP, p. 8.
[36] Public Service's SOP, pp. 8, 13.
[37] Public Service's SOP, p. 8.
[38] Hr. Ex. 166 (Attachment JWI-16), p. 13.

35. CIEA also recommends eliminating the use of the IA and instead requiring IPPs to submit affidavits signed by corporate officers supporting each CEP Project's repricing request. IPPs would provide the affidavits to Public Service, who could report the information to the Commission. Under this "fast-track" approach, CIEA would support a technology-specific reduced pricing flexibility of an up to three percent increase for solar, storage, or hybrid projects and up to six percent pricing flexibility for wind projects.[39]

36. As support for this position, CIEA argues that "[d]elay is the enemy" and that each month of delay causes cost increases.[40] CIEA argues that under Public Service's initially proposed IA process, the IA might not realistically complete its review of repricing submittal until approximately April 2025.[41] CIEA asserts that "the benefits of rigorous project pricing flexibility oversight via an IA and more regulatory process are outweighed by the risks of further increased project costs and decreased generation for resource adequacy in 2027 and 2028 due to project withdrawals or inability to meet as-bid [commercial operation dates]."[42]

37. COSSA/SEIA similarly argues against the IA approach in Stage 1. COSSA/SEIA acknowledges the IA may offer checks and balances and provide additional information but argues the IA process will introduce at least four additional months of delay.[43] Instead, COSSA/SEIA recommends the Commission authorize a three percent across-the-board price increase for solar, solar plus storage, and storage projects now based on the record associated with the CEP Delivery Motion filings. COSSA/SEIA argues this will avoid additional delays and price increases that could occur between now and March 2025. COSSA/SEIA states that it "is confident that increasing

[39] CIEA's SOP, p. 3.
[40] CIEA's SOP, p. 7.
[41] CIEA's SOP, p. 8.
[42] CIEA's SOP, p. 11.
[43] COSSA/SEIA's SOP, p. 3.

bid pricing by this amount will allow projects to get across the finish line toward contract execution."[44]

38. COSSA/SEIA questions the accuracy of the developer survey answers reflected in Hr. Ex. 166, Attachment JWI-17, Rev. 1, which reports the status of all of the projects and the scope of the requested price increases. COSSA/SEIA asks the Commission to refrain from exclusively relying on the information within this attachment, suggesting that the information is inaccurate and outdated.[45]

39. In its SOP, Interwest supports any plan that meets certain attributes that would help provide a quick path to project finalization. For Stage 1, Interwest's desired attributes include eliminating or minimizing the timeline and complexity of any IA process or additional regulatory review and incentivizing projects to sign agreements as soon as possible.[46]

40. In its SOP, Staff recommends adopting CIEA's initial proposal in which clean energy resources could request a price increase of between two to six percent by submitting affidavits of corporate officers to the Company, and the Company would then confirm this repricing in a compliance filing to the Commission.[47] Projects that do not require Stage 1 price relief should be expedited, remain eligible for Stage 2 relief (change of law), and could receive a one percent price increase without verification. Staff argues this option represents the best overall

[44] COSSA/SEIA's SOP, p. 11.
[45] COSSA/SEIA's SOP, pp. 6-7.
[46] Interwest's SOP, p. 1.
[47] While CIEA modified its position somewhat in its SOP, it initially proposed allowing IPPs to receive a price increase up to six percent in Component 1, Stage 1 without any IA review, with the understanding that such Stage 1 price increases could later be clawed back in Stage 2. Developers who are willing to execute PPAs right away could qualify for a one percent price increase without bidirectional Stage 2 exposure. (CIEA's CEP Delivery Response Comments, pp. 17-18).

approach to achieving price relief and that eliminating the IA will accelerate the development of all renewable projects.[48]

41. If the Commission moves forward with this approach, Staff argues two clarifications are necessary. First, the approach applies both to PPAs and utility-owned projects. For utility-owned projects, the Company would submit a filing with the Commission attesting to the need for the price increase. Second, Staff recommends the Commission specify that this price relief approach applies to projects in the approved portfolio. Only after an approved project has failed and the Company has gone through the established process for advancing backup bids could a backup bid also be eligible for Stage 1 price relief.[49]

42. In connection with its recommendation to approve pricing relief in Stage 1, Staff argues that the Commission should treat utility-owned generation and PPAs the same by applying a six percent price relief limit to the project's net present value ("NPV") for both ownership types as opposed to a six percent NPV for PPA projects and a six percent CtC baseline increase for utility projects. Staff argues the Commission should ignore the Company's protests and fashion the price relief for both PPAs and utility projects such that it is based on the NPV of the projects.[50]

43. In contrast to the parties arguing for the elimination of the IA, UCA recommends the Commission approve Public Service's initial Stage 1 proposal, including that the potential six percent cost increase would be confirmed by an IA.[51]

44. CEC asserts that the Commission must find a path forward that emphasizes transparency and scrutiny of any further cost increases. CEC does not oppose Public Service's initial proposal for an IA process so long as the IA process "is transparent and the results and IA

[48] Staff's SOP, pp. 3-4.
[49] Staff's SOP, pp. 4-5.
[50] Staff's SOP, pp. 6-7.
[51] UCA's SOP, p. 1.

decisions are subject to stakeholder investigation and challenge….”[52] In contrast, CEC “strongly opposes any proposal that would result in unnecessary and unverified automatic price increases not subject to scrutiny or verification through the IA or a similar process.”[53] CEC specifically includes in this opposition proposals to provide uniform cost increases to encourage projects to move forward, especially for those projects that have indicated that no price increase is necessary.[54]

45. CEC reasons that, while the Company’s initial proposal is not perfect, the third-party verification provided by the IA provides necessary customer protections and eliminate frivolous or unnecessary price increases.[55] CEC asserts that it is clear from the record that many solar and solar plus storage projects report the ability to execute PPAs at the as-bid PPA rate, assuming they could potentially obtain price relief from future changes of law.[56] CEC acknowledges the timing constraints but maintains the Company and Commission still have a responsibility to protect customers by providing cost increases only for actual and verifiable purposes and not provide unnecessary price increases.[57]

46. More specifically, CEC argues the Commission and Staff should have a role in selecting the IA to ensure that the IA is truly independent from the Company and bidders. In addition, CEC recommends expanding the process for Commission approval of an IA decision. CEC suggests that the 21-day review period be expanded and include an opportunity for intervenor

[52] CEC’s SOP, pp. 1-2.
[53] CEC’s SOP, p. 2.
[54] CEC’s SOP, p. 2.
[55] CEC’s SOP, p. 4.
[56] CEC’s SOP, p. 4.
[57] CEC’s SOP, p. 5.

comment before the Commission must issue a decision to ensure that interested stakeholders have an opportunity to review, audit, and weigh in on any proposed price increase. [58]

2. Findings and Conclusions

a. PPA Projects

47. The record contains considerable evidence that the current market dynamics and geopolitical environment have evolved since bids were submitted in March 2023 and factors such as supply chain constraints, policy uncertainty, and increased demand for clean energy projects have contributed to upward cost pressures.[59] Moreover, we agree with assertions from parties such as CIEA that further delay may cause additional price increases. We ultimately conclude that some amount of price flexibility is necessary to appropriately balance considerations of reliability, emissions reductions, and ensuring reasonable costs to customers.

48. The Commission agrees with Public Service, Staff, CIEA, COSSA/SEIA, and Interwest that the proposed IA-review process should be rejected for purposes of Component 1, Stage 1. The IA process will almost certainly result in several months of additional delays,[60] and additional delays will likely result in further price increases. Moreover, it is unclear how beneficial an IA would be in balancing the limited increases sought in Component 1, Stage 1 given the complexities of evaluating a variety of projects on an abbreviated basis. The risks that such a process would ultimately result in higher costs and the loss of important clean energy projects outweighs the benefits of a more robust project-by-project review of requested price increases. This is especially true for PPA projects, which do not require a subsequent CPCN proceeding.

[58] CEC's Comments on CEP Delivery, pp. 5-6.
[59] *See, e.g.*, Hr. Ex. 166 (Ihle), pp. 10-24.
[60] COSSA/SEIA's SOP, p. 3.

49. Thus, PPA solar, solar plus storage, and storage projects may receive a maximum price increase of one percent in Stage 1. The PPA wind project may receive up to a six percent price increase. This Stage 1 price relief flexibility for the PPAs is supported by the record evidence including the Company's testimony during the evidentiary hearing and especially the highly confidential updated pricing information contained in Hearing Exhibit 166, Attachment JWI-17, Rev. 1.

50. To receive the Stage 1 price increase, PPA developers must present to Public Service affidavits signed by corporate officers providing narrative descriptions supporting the requested increase and agreeing to the bidirectional nature of Stage 2 and the fact that Stage 1 and Stage 2 relief is considered in the aggregate. In other words, projects that receive a Stage 1 price increase could be subject to a price decrease in Stage 2.[61] Additionally, any Stage 1 price increase counts against the 15 percent cap on price increases possible in Stage 2. Thus, if a project obtains a six percent price increase in Stage 1, it would only be eligible for an additional nine percent price increase based on change of law in Stage 2. Projects that move forward without Stage 1 price relief would still be eligible for Stage 2 price increases but would not be subject to any Stage 2 price decreases. This strikes the balance of allowing bidders to move forward with contracts immediately if they currently have no price increase needs but allows for them to return if there is a change of law that significantly impacts their ability to deliver the project at the bid price. For clarity, and consistent with Staff's position, backup projects may also utilize the Stage 1 price relief mechanism but only after full efforts have been made to move forward with the approved projects and after the approved backup bid selection process is employed.

[61] This is directionally consistent with CIEA's initial proposal in which developers would "agree to the terms of a 'bidirectional' claw back of Stage 1 increases in its PPA, as well as liability for fraudulent statements." (CIEA's Comments, p. 17).

51. We recognize the arguments from CEC, UCA, and Climax that across-the-board price increases risk unnecessarily increasing costs to ratepayers and might constitute an unreasonable windfall for developers at ratepayer expense. However, a lengthy project-specific review might also unnecessarily increase costs through additional delay and threaten the viability of multiple clean energy projects, which could raise additional resource adequacy concerns. The cap on Stage 1 price increases together with the bidirectional nature of Stage 2 and the aggregate 15 percent cap for Stage 1 and Stage 2 price increases help weigh these concerns and reduce the risk that projects will obtain an unnecessary price increase in Stage 1. Further, our decision to defer consideration of the requested price increases for utility-owned projects until the CPCN proceedings as discussed below is consistent with arguments that there must be a project-specific review of each price increase.

b. Utility-Owned Projects

52. Given the differences between utility-owned projects and PPA projects, the Commission finds it appropriate to adopt a different Stage 1 approach for utility-owned clean energy projects. Contrary to Public Service's request, we defer granting a presumption of prudence for the proposed price increases or modifying the CtC PIM baselines until the appropriate CPCN proceedings. The Commission and interested stakeholders will be able to evaluate the validity of the requested price increases during the CPCN proceedings in much the same way that Public Service initially anticipated the IA would evaluate price increases. Because Public Service must still obtain CPCNs for the clean energy projects for which it now seeks price relief, withholding approval of the price increases until the CPCN proceedings will not result in any meaningful delay nor the associated concerns about additional price increases and resource adequacy related to further delay, making this distinct from the procedural path for PPA projects.

Moreover, it appears that Public Service is prepared to file CPCN filings for its wind projects in the near future. During the hearing, the Company represented that CPCNs for Bid 1015 and Bid 1024 should be filed about a week after hearing, while the CPCN for Bid 1029 would be filed in early December.[62]

53. Our decision to defer consideration of the requested price increases for utility-owned clean energy projects is similar to the requests of Staff and CEO for the Commission to defer consideration of price increases for the Company's thermal units,[63] and is directionally consistent with Public Service's alternative proposal for those thermal projects.[64] As determined in the respective CPCN proceedings, costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and operational PIM baselines. For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing may potentially constitute extraordinary circumstances within the terms of the CtC PIM (*i.e.*, unforeseen costs that could not have been known at the time the bid was made), subject to future adjudication by the Commission following development of the relevant project. Similarly, although potentially less applicable, the same would be true for the operational PIM. Moreover, prudently incurred costs associated with each of the projects will be eligible for recovery; provided, however, that this in no way impacts the application of the PIMs. For instance, the Company may earn a disincentive under the CtC PIM regardless of whether the underlying costs are imprudent.

54. In addition to the above findings, we clarify that utility-owned clean energy projects are subject to the same price cap as the respective PPA projects. Thus, the Company-owned wind

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[62] Hr. Tr. November 7, 2024, pp. 138-39.
[63] Staff's SOP, p. 9; Hr. Ex. 1204 (CEO Response Testimony), pp. 20-21.
[64] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 19.

projects are only eligible for up to a six percent Stage 1 price increase in the CPCN proceedings, consistent with the Company's SOP,[65] and the utility-owned storage project would only be eligible for up to a one percent Stage 1 price increase in the CPCN proceeding. Importantly, this maximum six percent increase and maximum one percent increase shall be applied to the NPV of the respective projects, consistent with the price increases permitted for PPAs, and not on the CtC as the Company requests.

55. On this last point, we find Staff's arguments persuasive. Public Service's proposal to apply the percentage price increase to the project's construction costs for utility-owned clean energy projects but only to the NPV for PPA projects puts utility projects and PPA projects on an unlevel playing field. This unequal treatment could result in utility-owned projects receiving a larger price increase than an otherwise equivalent PPA project.[66] Public Service's own filings demonstrate the issue. A six percent increase on the construction cost of a wind project "translates to a higher percentage increase when compared to the smaller PTC-adjusted cost."[67] More precisely: "the 'six percent of baseline' cost increase divided by a smaller denominator (the PTC cuts approximately half of the cost of the project) ends up at about 12 percent on the PTC-adjusted costs."[68]

56. Public Services raises several arguments against Staff's proposal to limit the percentage price increases to an NPV basis, none of which are persuasive. For instance, the Company argues there are material distinctions between utility-owned and PPA projects and that converting an NPV adjustment to a new CtC baseline is complex.[69] While we agree that material

[65] Public Service's SOP, p. 8.
[66] Hr. Ex. 2709 (Staff Response), p. 20.
[67] Hr. Ex. 166, Attachment JWI-16 (Supplemental Comments), p. 13.
[68] Hr. Ex. 166, Attachment JWI-16 (Supplemental Comments), p. 13.
[69] Hr. Ex. 166, Attachment JWI-19 (Reply Comments), pp. 9-10; Public Service's SOP, p. 7.

differences exist between utility-owned and PPA projects, the Company has not established how any of these differences justify additional price flexibility for utility-owned projects. Public Service knew of these differences and presumable accounted for them when the Company formulated its Phase II bids that now serve as the baseline for the Company's projects. As for the complexity of converting an NPV adjustment to a new CtC baseline, Staff asserts that the Company "grudgingly admits" that it could calculate the NPV for utility projects. According to Staff, all of the necessary information to perform this calculation is contained in the project-by-project updated revenue requirements that Staff obtained in discovery.[70] Moreover, interested parties and the Commission will be able to work through these details in the follow on CPCN proceedings.

57. In its Reply Comments, Public Service makes two alternative requests if the Commission adopts Staff's NPV approach. First, the Company states the NPV approach results in reduced CtC baselines and thus asserts the Commission should modify the methodology used to calculate the incentives and disincentives under the CtC PIM. Specifically, the Company requests the Commission adopt the progressive method as opposed to the landing spot method.[71] Second, the Company argues the Commission should "convert the maximum NPV increase (such as 6%) to a revised CtC for each project, thus setting a new baseline CtC now and avoiding the need for recalculating NPV in the future."[72]

58. We decline to adopt the Company's two alternative requests at this time. Regarding the first request, in the First RRR Decision we rejected the Company's request to switch to the progressive method on the basis that doing so would significantly reduce the level of potential incentives and disincentives under the CtC PIM.[73] In its CEP Delivery Motion filings, the

[70] Staff's SOP, pp. 6-7.
[71] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 11.
[72] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 10.
[73] First RRR Decision, ¶¶ 122-23.

Company does not address this shortcoming with the progressive method. Consistent with our earlier

First RRR Decision, in the CPCN proceedings Public Service may request to implement the progressive method in such a way that is supported and roughly maintains the respective amounts of incentives and disincentives.

59. Similarly, we defer the Company's second request to convert the NPV increase to a revised CtC baseline to the respective CPCN proceedings. In the CPCN proceedings, the Commission and parties can evaluate the actual reasons behind the Company's price increases and the appropriate amount of price relief. The Company's suggestion may be reasonable, but it is unnecessary and premature to rule on the proposal at this time.

E. Component 1, Stage 2

1. Party Positions

60. As proposed, Stage 2 of Component 1 would allow developers to seek additional price relief based on changes of federal law. The Stage 2 process would be initiated by a motion filed by the Company, Staff, or by the Commission on its own motion, describing the change in law and explaining why Stage 2 relief is appropriate. After considering responses to the motion, the Commission would determine whether to initiate a Stage 2 relief process. After Stage 2 is initiated, any requests for relief must be completed through submittal to the IA no later than December 31, 2025, or 18 months prior to the project's commercial operation date ("COD"), whichever is later.[74] In addition, bidders would be required to submit requests and documentation to the IA within 30 days of any Commission decision approving Stage 2 relief. After the IA makes its verification, it would then submit all materials to the Commission. The Commission would

[74] Hr. Ex. 166 (Ihle), p. 52.

have 21 days to review the IA's verification and, at the Commission's discretion, suspend the requested relief. If the Commission suspended the requested price relief, then there would be a 10-day intervenor comment period, a seven-day Company and bidder response period, and a Commission decision to approve or reject the requested relief within 14 days after the Company response.[75]

61. Stage 2 relief would provide up to a 15 percent total price increase, inclusive of any prior approved increase in Stage 1.[76] Stage 2 is also bidirectional. For example, if PTC/ITC benefits increase, or if current tariffs are repealed, the Company could file for a reduction to the underlying PPA rates (for IPP bids) and CtC PIM baseline costs (for self-build and build-transfer bids).[77]

62. In the event the Commission or the IA rejects all or a portion of a requested and verified Stage 2 increase, a project with an executed PPA would be able to terminate the PPA and receive a 75 percent refund of its Security Fund under Article 11 of the Model PPA if it so elects within 14 days of the Commission decision. Similarly, a build-transfer project could terminate its contract with the Company by paying 25 percent of the Termination Payment.[78] Public Service proposes to implement the Stage 2 process by incorporating the proposed PPA language in Hearing Exhibit 166, Attachment JWI-20.

63. Although Public Service proposes to eliminate the IA in Stage 1, in its SOP the Company continues to support the Stage 2 IA process as initially presented. Public Service reasons that the IA concept "continues to have merit in Component 1, Stage 2, where the time pressures may not be as acute as the current ones and where the required assessments would be more discrete

[75] Hr. Ex. 166 (Ihle), pp. 43, 53.
[76] Hr. Ex. 166 (Ihle), p. 51.
[77] Hr. Ex. 166 (Ihle), p. 51.
[78] Hr. Ex. 166 (Ihle), p. 53-54.

and less subjective."[79] Public Service "requests approval of a Stage 2 process for all PPA and [utility-owned] projects with the same timing and triggers as proposed in the CEP Delivery Plan."[80]

64. In its SOP, Public Service argues the Stage 2 price relief mechanism "would not cover all potential changes in law, such as a full and immediate repeal of the Inflation Reduction Act ("IRA") or repeal of relevant tax credits made available or extended by the IRA."[81] The Company states it is committed to working with developers to address such scenarios, including how posted security is treated under these types of circumstances. In addition, Public Service requests guidance from the Commission as to whether it anticipates using an IA for determining price changes in the event Stage 2 is triggered. The Company asserts an IA could assist the Commission in confirming the project-specific impacts of changes of law in an objective, expedient manner that would significantly reduce the burden on the Commission.[82]

65. In Staff's SOP, Staff largely agrees with the Stage 2 price relief concept. Staff argues that whether Stage 2 price relief is permitted and the level of that price relief should be at the Commission's discretion, up to a maximum of 15 percent inclusive of Stage 1 relief. Consistent with CIEA's initial recommendation, Staff argues that Stage 2 price relief should be bidirectional, except for those projects that agree to go forward with only a one percent increase in Stage 1. For those projects, Stage 2 price relief should only be upward.[83] CEO likewise generally supports the Company's proposed process for Stage 2 pricing relief.[84]

66. In its SOP, CIEA argues for a more generous Stage 2 price relief structure. CIEA reasons the election has changed the calculus regarding the likelihood and scope of potential

[79] Public Service's SOP, p. 6.
[80] Public Service's SOP, p. 14.
[81] Public Service's SOP, p. 14.
[82] Public Service's SOP, p. 16.
[83] Staff's SOP, p. 16.
[84] Hr. Ex. 1204 (CEO Response Testimony), p. 17.

changes of law. According to CIEA, projects that move fast may lock-in existing PTCs, but further delays risk changes of law.[85] While CIEA continues to support the general concept of an IA review of change of law impacts in Stage 2, it argues that several modifications are now necessary. CIEA states it is "imperative" that the Commission allow developers to recover 100 percent of their security payments if projects must withdraw due to a change in law that causes cost increases of over 15 percent for any project. CIEA asserts that if the PTC/ITC is repealed, costs could rise by 100 percent. CIEA similarly argues that even short of a full repeal, partial repeals or changes in tax credit values or tariff amount could all devastate clean energy projects.[86]

67. If the PTC/ITC is repealed or a change in law results in a price increase of more than 15 percent, CIEA also asks that the Commission request full repricing from all CEP projects without the 15 percent Stage 2 limit.[87] CIEA further asks that the Commission extend by one year the December 31, 2025, deadline for bidders to request Stage 2 price relief. CIEA states that changes in law are likely to pass in 2026, so the deadline should be December 31, 2026.[88] CIEA does not oppose the bidirectional nature of Stage 2 but argues developers should be allowed to defend against a downward Stage 2 reduction by showing that their projects did not benefit from a price reduction.[89] Finally, CIEA provides redlined modifications to Public Service's proposed PPA language in Hearing Exhibit 166, Attachment JWI-20. CIEA makes it clear that it "does not request Commission approval of such modified language but provides the redline as an example to demonstrate IPP concerns about potential large, more structural changes of law that now must be taken into account."[90]

[85] CIEA's SOP, pp. 14-15.
[86] CIEA's SOP, p. 16.
[87] CIEA's SOP, p. 5.
[88] CIEA's SOP, pp. 5, 15.
[89] CIEA's SOP, p. 5.
[90] CIEA's SOP, p. 5.

68. In its SOP, COSSA/SEIA strongly supports the Stage 2 price relief for changes in law. COSSA/SEIA further supports retaining an IA to review any requests for Stage 2 price relief, reasoning that "there will be more time for successful bidders to request price relief, for the IA to review the request, and for the Commission to approve that price relief."[91] Nevertheless, COSSA/SEIA does request changes to the Stage 2 process. COSSA/SEIA asks for an appeals process in which a developer could request Commission review of a price increase that is denied by the IA. COSSA/SEIA asserts the appeal should take place in a separate Commission proceeding so that individual developers could seek Commission review of an unfavorable IA decision.[92] COSSA/SEIA also argues against the PPA language Public Service proposes in Attachment JWI-20. COSSA/SEIA asserts the Company's current language forces developers to bear all the risk, including losing their security deposit, if the IA or the Commission denies the requested price relief. COSSA/SEIA does not propose specific changes but asks that the Commission "adopt language that directs the Company to renegotiate bid security terms in any situation where Stage 2 price relief is denied by the Commission."[93]

69. More generally regarding PPA provisions, COSSA/SEIA argues the Commission "should refrain from making any determinations regarding the reasonableness or acceptability of any particular PPA provision."[94] COSSA/SEIA particularly cautions against any Commission finding related to the security provisions in Hearing Exhibit 166, Attachment JWI-21. COSSA/SEIA argues that PPA terms cannot be viewed in isolation but must be seen in the context of the larger give-and-take negotiation.[95]

[91] COSSA/SEIA's SOP, pp. 3-4.
[92] COSSA/SEIA's SOP, p. 4.
[93] COSSA/SEIA's SOP, p. 4.
[94] COSSA/SEIA's SOP, p. 6.
[95] COSSA/SEIA's SOP, p. 5.

70. Interwest argues that quick decision making and a fair and robust opportunity for project developer level input is critical if there are any future changes in law or tariff.[96]

71. In its SOP, UCA recommends the Commission approve the Company's plan for a potential 15 percent price increase in Stage 2.[97] UCA opposes, however, the Company's proposal to partially refund security deposits or other walk-away provisions. UCA reasons that security deposits provide a substantial incentive for developers to go forward with their projects or to minimize the requested price increase. UCA argues that developers knew their security deposits were at risk when they submitted their bids, and the security deposits should not be reduced or lost.[98]

2. Findings and Conclusions

72. The general concept of a Stage 2 process to addresses changes in law has widespread party support and appears to be critical for most, if not all, of the clean energy projects.[99] The Company's proposed Stage 2 process is a useful structure that will encourage developers to move forward with projects even though future tariffs or changes to tax credits might impact the projects' financials. Therefore, the Commission adopts the Company's proposed Stage 2 process for both PPA and utility-owned projects, subject to the below modifications and clarifications.

73. Although a project-specific IA review in Stage 1 is inappropriate for the reasons discussed above, we agree with several of the parties that an IA review in Stage 2 appears useful and efficient. We find persuasive the Company's arguments that an IA review has merit in Stage 2, "where the time pressures may not be as acute as the current ones and where the required

[96] Interwest's SOP, p. 3.
[97] UCA's SOP, p. 9.
[98] Hr. Ex. 509 (UCA Testimony), pp. 26-27.
[99] Hr. Ex. 166, Attachment JWI-17, Rev. 1.

assessments would be more discrete and less subjective."[100] Consistent with the Company's request in its SOP for more guidance regarding the role of the IA, we clarify that the IA will ideally provide independent analysis of the documentation provided by the various developers and will produce initial determinations as to whether price modifications are appropriate. The methodology underlying these determinations should be consistent across all relevant projects, regardless of technology or ownership type.

74. To ensure the IA is ready and available if and when needed, Public Service shall confer with Staff and UCA on the selection of an IA and development of a scope of work. The Company must submit a motion to approve the proposed IA together with an IA scope of work no later than March 31, 2025. Public Service's proposal to defer costs associated with the IA and recover them through the ECA seems reasonable, but Public Service must set forth the specifics of its proposed cost recovery mechanism in the March 31, 2025 motion. Parties to this Proceeding would have 14 days to file any responses to the Motion. Establishing this process at the outset will hopefully save time if and when Stage 2 is triggered.

75. Consistent with CEC's arguments for additional transparency, the Commission finds that certain modifications to the proposed IA review process are necessary. First, intervenors should have an opportunity to review and comment on the IA's Stage 2 determinations prior to a Commission decision. Intervenors shall have 21 days to review the IA's initial determination. Public Service and any impacted developer would then have seven days to file response comments. The IA's determination would not go into effect until the Commission decision, which would be issued in due course.

[100] Public Service's SOP, p. 6.

76. We generally agree with the Company that any requests for Stage 2 relief should be submitted to the IA no later than December 31, 2025, or 18 months prior to the project's COD. We empathize, however, with concerns from CIEA that changes in law might occur in 2026. Thus, while we adopt the Company's proposed deadline at this time, parties may petition for an extension as necessary.

77. Consistent with our discussion above, we emphasize that the Stage 2 process is bidirectional for any projects that received Stage 1 price relief. Projects that did not pursue and receive Stage 1 price relief are still eligible for Stage 2 relief, but only in the upward direction.[101] We agree with CIEA that pricing relief obtained in Stage 1 would be "[s]ubject to downward adjustment in Stage 2."[102] We further agree with CIEA, however, that developers are permitted to argue via the established Stage 2 process that their projects should not be subject to a price reduction.

78. We recognize the importance of clarifying the consequences if a developer does not obtain the requested Stage 2 relief or if such relief is insufficient to address the change in law. The Commission adopts the Company's initial approach in which developers could terminate the PPA/build-transfer agreement if their Stage 2 price relief was denied and only pay 25 percent of the security deposit/termination payment, so long as the developer elects to do so within 14 days of the Commission decision. Adopting the contrary approach supported by CIEA and COSSA/SEIA and allowing developers to terminate their contracts with no financial consequences if any portion of their Stage 2 request is denied would incentivize all developers to request the full 15 percent price relief and would put significant pressure on the IA and Commission to approve

[101] Public Service's SOP, p. 15.
[102] CIEA's SOP, p. 6; *see also*, CIEA's Comments, p. 17.

the Stage 2 requests without modification. In contrast, requiring developers to pay at least 25 percent of the security deposit/termination payment incentivizes developers to move forward with the projects at or below the 15 percent price cap. PPA provisions that allow bidders to renegotiate bid security terms or walk away with more than 75 percent of the security deposit/termination payment if any portion of a bidder's Stage 2 request is denied would be contrary to this Decision.

79. While the Commission empathizes with UCA's request that developers be required to pay 100 percent of their security deposit if they withdraw, the Company's 25 percent threshold is a more balanced approach. UCA's request ignores the substantial uncertainty that future changes in law pose to CEP projects. Allowing developers to recover 75 percent of their security deposit/termination payment will encourage serious projects to execute PPAs/build-transfer agreements, despite the uncertain future.

80. A related issue is CIEA's argument that developers be allowed to recover 100 percent of their security payments if projects must withdraw due to a change in law that causes cost increases of over 15 percent for any project. In the event there is an established change of law that exceeds the 15 percent cap, we agree that developers should be allowed to terminate their PPAs and recover 100 percent of their security payments. Allowing this type of flexibility in the event of a significant change in federal law will again encourage developers to execute PPAs and attempt to develop their projects. To be clear, this full return of the security payment would not be allowed whenever a developer claims that a change in law increased prices by more than 15 percent. Rather, this option would only be available after a developer establishes to the

Commission's satisfaction that a project experienced a legitimate price increase of more than 15 percent and this price increase is directly caused by a change in law.[103]

81. We decline from approving at this time CIEA's request that the Commission request repricing from all CEP projects without the 15 percent Stage 2 cap if there is a significant change in federal law. At some point, the Commission may be better off allowing impacted CEP projects to fail and relying on the JTS to reestablish the market price for clean energy projects.

82. Finally, we find COSSA/SEIA's request to establish a separate appeals process for bidders to be unnecessary and duplicative of existing avenues. Under the Stage 2 process established above, bidders already have an opportunity to provide input in the seven-day response period.[104] With the established Stage 2 IA process and the Commission's existing provisions for third parties to file a complaint to initiate a new proceeding, we do not see the need to create an additional appeals process per COSSA/SEIA's request.

F. Other Component 1 Issues

1. Selection of Additional Solar and Solar Plus Storage Bids

83. In addition to its other arguments regarding Component 1, UCA argues the Commission should consider selecting additional solar and solar plus storage bids. UCA asserts the large increase in future capacity need shown in the Company's initial JTS filings in Proceeding No. 24A-0442E supports taking additional capacity in this Proceeding.[105] UCA recommends the Company investigate whether the lowest-cost solar and solar plus storage projects are able to go

[103] For purposes of determining whether a project can recover 100 percent of its security deposit, the 15 percent threshold is based on the project's initial as-bid price, even if a project obtains a price increase in Stage 1. For instance, if a project received a six percent price increase in Stage 1, the developer would still be required to show more than a 15 percent price increase due to a change of law—even though the project would only be eligible for a nine percent price increase in Stage 2.

[104] *Supra* ¶ 75.

[105] UCA's SOP, pp. 4-5.

ahead under the proposed price increases proposed in Component 1. UCA specifically focuses on Bids 0718, 0649 and 0651 (all solar projects) and Bid 0567 (a solar plus storage).[106]

84. The Commission denies UCA's requests to investigate whether additional solar and solar plus storage projects can move forward under the Component 1 price relief mechanism. It is far from clear on this record that the additional bids UCA flags could move forward under Component 1 or that there should be a presumption of prudence for their acquisition. For instance, it is uncertain whether the interconnections for these new projects could be timely achieved. While we ultimately deny UCA's recommendation, we note that Public Service could always seek authorization to pursue such additional projects outside of the JTS Proceeding, especially if the Company sees a potential cost-savings or reliability benefit.

2. Presumption of Prudence for Incremental Cost Increases

85. CEC raises the additional argument that any incremental cost increase in Component 1 should not be afforded the presumption of prudence per Rule 3617(d). CEC reasons the proposed Component 1 cost increases "would occur outside of the Commission's competitive solicitation rules" and thus any approved cost increases should be subject to prudence challenges.[107] CEC further argues that escalating CEP costs were foreseeable and predicted by the Independent Evaluator Report.

86. We reject CEC's argument regarding the application of Rule 3617(d). Given the competitive bidding process underlying the initial selection of these bids, the evidence put forth regarding the need for price increases, and the process and protections inherent in the Stage 1-Stage 2 mechanisms, price increases awarded under Component 1 will carry a presumption of prudence

[106] UCA's SOP, p. 6.
[107] CEC's SOP, p. 3.

per Rule 3617(d). This will help provide Public Service the regulatory certainty it needs to quickly pursue these clean energy projects and avoid future delays and cost increases.

G. PPA Execution and Requests for Rule Variances

1. Party Positions

87. In its CEP Delivery Motion, Public Service seeks variances from Rule 3613(i) and Rule 3613(j). Under Rule 3613(i), a utility must execute contracts for resources within 18 months after the utility's receipt of bids to receive the presumption of prudence per Rule 3617(d). This deadline was September 1, 2024. Public Service seeks a six-month extension so that the new regulatory deadline to execute contracts is March 1, 2025. [108] Under Rule 3613(j), a utility must file a proposal within 14 months after the receipt of bids that addresses the public release of all confidential and highly confidential information related to bids. The deadline for this filing was May 1, 2024. Public Service proposes to extend this deadline by at least 11 months to April 1, 2025. Public Service states that the bids are in a very sensitive state and may change based on the relief contemplated in the CEP Delivery Motion.[109]

88. CIEA, COSSA/SEIA, and Interwest all argue the Commission should act to prevent further delays in executing PPAs. CIEA asserts Public Service's delay in PPA executions is a contributing factor for the need for price increases and that Public Service appears to be "understaffed and overwhelmed."[110] In its Response Comments, Interwest states that "timeliness" is the most critical factor in achieving the goals of the CEP and that the available time to complete

[108] CEP Delivery Motion, p. 14.
[109] CEP Delivery Motion, p. 15.
[110] CIEA's CEP Delivery Comments, p. 20.

projects and meet CODs is becoming prohibitively short.[111] Interwest further asserts there have been significant delays during contract negotiations due to the Company's own action.[112]

89. To prioritize PPA execution going forward, CIEA recommends the Commission require Public Service to submit by December 31, 2024, a filing updating the Commission on all PPA negotiations, and every month thereafter. CIEA also suggests the Commission direct the Company to prioritize quicker PPA execution over holding the line on withdrawal "outs" and penalties for IPPs. That said, CIEA expressly asks that the Commission take no action on the specific terms of PPAs presented by Public Service at this time.[113]

90. COSSA/SEIA critiques the Company's requested variance of Rule 3613(i) in the context of delayed PPA execution. COSSA/SEIA argues that Rule 3613(i) puts pressure on the Company to execute PPA and build-transfer contracts swiftly. According to COSSA/SEIA, granting the Company's requested variance would reward "the bad behavior and foot-dragging that occurred from the Company not executing contracts in a timely manner."[114] COSSA/SEIA recommends the Commission deny the requested variance and reserve its decision to grant or deny the presumption of prudence until after the CEP Delivery bids are finalized.[115] In the alternative, COSSA/SEIA argues that if the Commission grants the variance, the revised deadline for compliance should be as short as possible and a firm deadline that is not subject to additional delays. COSSA/SEIA suggests the extended deadline should be December 31, 2024. COSSA/SEIA also asks that the Commission confirm that bid prices will become public on that date.[116]

[111] Interwest's Comments, pp. 2-3.
[112] Interwest's Comments, p. 6.
[113] CIEA's SOP, p. 7.
[114] COSSA/SEIA's SOP, p. 9.
[115] COSSA/SEIA's SOP, p. 9.
[116] COSSA/SEIA's SOP, pp. 9, 12.

91. In its Reply Comments, Public Service asserts it is negotiating in good faith with all bidders and warns the Commission against relying on the unattributed statements from COSSA/SEIA and CIEA. Public Service asserts several PPA are in near-final draft form and that this demonstrates the Company's ability to reasonably negotiate with IPPs. For other bids, Public Service says there are issues outside of the Company's control, such as a developer's need for price relief or insistence on receiving a Component 1, Stage 2 relief mechanism.[117] The Company states that negotiations of long-term, multi-million-dollar contracts are always challenging and that while it agrees on the importance of executing PPAs, the timeframe for these negotiations is not atypical.[118] The Company asserts that no IPP developers were able to execute a PPA given the need for either direct pricing relief or assurances of relief in the event of future changes in tariffs or the availability of tax credits.

92. Ultimately, Public Service proposes to submit monthly reports, beginning in January 2025, on the status of negotiations for all PPA and IPP build-transfer projects. The Company states that these reports will be similar in form to Table 1 in the Company's October 4 Supplemental Filing, Hearing Exhibit 166, Attachment JWI-16HC. The Company commits to continue this monthly reporting until all PPAs for the CEP are executed.[119]

2. Findings and Conclusions

93. The Commission agrees that timeliness is a critical factor for the CEP's success. Indeed, this urgency is one of the main factors supporting our decision to eliminate the IA process in Stage 1 of Component 1 for PPA projects. Our decisions providing bidders and the Company

[117] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 30.
[118] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 28; Public Service's SOP, pp. 16-17.
[119] Public Service's SOP, p. 17.

more certainty regarding Component 1 price relief processes and the extent to which bidders can recover their security deposit should also help accelerate the negotiation process.

94. Nevertheless, the Commission denies CIEA's suggestion to direct Public Service to prioritize quicker PPA negotiations over penalties if IPPs walk away from the PPA. Apart from our earlier decisions regarding the recovery of security deposits, we see little value in issuing vague directives to focus on executing PPAs at the expense of other contested terms. As to CIEA's request that the Commission take no action on specific PPA terms, we agree that there is no need for the Commission to approve specific PPA provisions at this time.

95. Regarding CIEA's request for monthly updates from Public Service on all PPA negotiations, it appears that Public Service largely agrees with this concept. Consistent with the proposals from CIEA and Public Service, we direct the Company to submit monthly reports in this Proceeding on the status of negotiations for all PPA and IPP build-transfer projects. These negotiation reports shall be due on the fifth of every month,[120] and will continue until all PPAs and build-transfer agreements for the CEP are executed. Public Service shall confer with the individual bidders on the negotiation status that the Company intends to provide in the negotiation report. Conferral confirmation must be provided in the report to the Commission.

96. Turning to COSSA/SEIA's opposition to the Company's requested variance of Rule 3613(i), we agree that Rule 3613(i) ideally should incentivize Public Service to execute PPAs swiftly. We disagree, however, with COSSA/SEIA's primary recommendation to deny the variance and defer granting a presumption of prudence until after bids are finalized. Removing regulatory certainty in this way might cause additional delays. COSSA/SEIA's alternative

[120] The first report requirement shall commence the fifth of each month following issuance of this Decision, with an initial report for January of 2025 provided as soon as practicable following issuance of this Decision.

recommendation of a December 31, 2024 deadline is not feasible. Therefore, we grant the Company's requested variance and adopt the March 1, 2025 deadline the Company proposes in the CEP Delivery Motion. We clarify, however, that any request to extend the March 1 deadline must be accompanied with a detailed description of Public Service's efforts specific to each individual PPA and build-transfer agreement. Similar to the monthly negotiation reports but with more detail, Public Service shall confer with the individual bidders on the information the Company intends to provide regarding efforts to finalize PPAs, and conferral confirmation must be included.

97. We also grant Public Service's variance from Rule 3613(j) regarding the public release of bid information. We agree with the Company that the bids are in a "sensitive state" and it is too soon to publicly release confidential information regarding such as bid prices. The April 1, 2025 deadline is a reasonable amount of time for Public Service to submit a proposal for the public release of such information.

H. JTS Proceeding

1. Party Positions

98. Several parties recommend the Commission take certain actions regarding the ongoing JTS Proceeding in light of the challenges presented in the CEP Delivery Motion. For instance, Staff argues that in the JTS Proceeding, the Commission should consider consequences for bids that have failed in this process from reappearing in the JTS Proceeding. Such consequences could include higher bid fees or stricter walkaway provisions.[121] Staff suggests the Commission consider consequences for bids that have failed in this process that reappear in the JTS Proceeding (*e.g.*, higher bid fees or stricter walkaway provisions). Staff does not

[121] Staff's SOP, p. 17.

recommend setting such consequences here but encourages the Commission to inform bidders that withdrawing an approved bid submitted in this ERP only to re-bid the same project in the JTS Proceeding may result in heightened review or financial scrutiny.[122] CEO similarly suggests that bids that receive Component 1 price relief only to pull out of this process and bid into the JTS Proceeding could be subject to higher bid security fees, stricter walk-away provisions, or other measures that will increase the surety of future contracts.[123]

99. UCA opines that the Company and the Commission have been lax in ensuring that IPPs are not advantaging Colorado's ERP system. UCA recommends that any projects that pull out of this Proceeding from this point forward be ineligible to bid in the JTS Proceeding.[124]

100. COSSA/SEIA and CIEA make sweeping suggestions for how to reform the JTS Proceeding. For instance, COSSA/SEIA suggests setting a deadline in the JTS Proceeding for the expiration of bid pricing after which bidders would be allowed to refresh pricing.[125] One of CIEA's suggestions is for the Commission to consider a "best and final" pricing opportunity in the JTS Proceeding for IPPs to sharpen their pencils and adjust pricing after the levelized cost screening.[126]

101. Interwest states that the extended timelines in the Proceeding are putting investment at risk. Interwest warns that if development risks in Colorado are not reduced in future solicitations by trimming delays "the state may risk losing its appeal as a key focus for renewable project development."[127] According to Interwest, it is critical for the Commission to be able to fully investigate the Company's management of the CEP resource solicitation such that the problems in this Proceeding are not repeated in the JTS Proceeding and that "[the Company's] rhetoric be

[122] Hr. Ex. 2709 (Staff Response), p. 26.
[123] Hr. Ex. 1204 (CEO Response Testimony), p. 16.
[124] Hr. Ex. 509 (UCA Testimony), p. 11.
[125] Hr. Ex. 2202 (COSSA/SEIA Response Testimony), pp. 34-36.
[126] CIEA's Response Comments, pp. 26-27.
[127] Interwest's Comments, p. 3.

reviewed through a factual lens."[128] Interwest accordingly requests that the Commission make numerous changes to the JTS Proceeding. For instance, Interwest ask that Public Service be required to submit a separate filing in its JTS Proceeding with an analysis of every point in the CEP where any delay could have been avoided and suggestions for preventing similar delays in the JTS Proceeding.[129] Interwest also recommends the Commission require Public Service to include a bid price expiration deadline and to develop a PIM that would reward Public Service for conducting timely portfolio reviews and executing contracts efficiently.[130]

2. Findings and Conclusions

102. We reject the various suggestions to use this Proceeding to set new requirements for the currently ongoing JTS Proceeding. The intervenors in the JTS Proceeding are welcome to propose modifications in that proceeding, where they can be adjudicated by all parties in the JTS Proceeding.

103. We similarly deny suggestions from Staff, CEO, and UCA that there should be some type of predetermined consequence in the JTS Proceeding if a bidder abandons a project that was proposed in this Proceeding given all the difficulties, delays, and challenges that have occurred. That said, parties in the JTS Proceeding are free to argue that a particular bidder or a bidder's pricing is unreliable because of past actions. The Commission will consider such arguments as they come before us, but we decline from using this Proceeding to decide how bidders in the JTS Proceeding will be evaluated.

[128] Interwest's Comments, pp. 3-4.
[129] Interwest's Comments, p. 7.
[130] Interwest's Comments, pp. 8-9.

I. Replacement for Bid 0235

1. Party Positions

104. In the CEP Delivery Motion, Public Service seeks authorization to replace Bid 0235 (a 219 MW new-build PPA thermal resource that was included in the approved resource portfolio but is no longer available) with Bid 1000 (a Company-owned thermal resource). The Company separately seeks authorization to extend the PPA for Plains End (an existing 219 MW PPA thermal resource) to add additional capacity to its system.[131] Public Service argues the additional capacity it seeks in the CEP Delivery Motion is reasonable given the already tight summer capacity positions the Company is facing. The Company further reveals it has updated its methodologies for the planning reserve margin ("PRM") and effective load carrying capability ("ELCC") values and is developing a new base load forecast in advance of the JTS. Based on these new assumptions, the Company asserts it is facing real and substantial capacity needs in the coming years.[132]

105. CEO opposes the Company's proposal and recommends the Commission approve the Plains End PPA extension as the replacement for PPA Bid 0235. CEO notes that in the Phase II Decision, the Commission approved 669 MW of nameplate thermal capacity via Bids 0989, 0997, 0011, and 0235. Public Service now asks that the Commission approve 869 MW of nameplate thermal capacity via Bids 0989, 0011, and 1000, and by extending the Plains End PPA contract.[133] CEO argues that the Company does not need to secure an additional 200 MW of capacity at this time.[134] CEO asserts that the Commission's decision should be based on the facts that have been litigated in the instant proceeding.[135]

[131] CEP Delivery Motion, p. 9.
[132] Hr. Ex. 166 (Ihle), pp. 106-10.
[133] Hr. Ex. 1204 (CEO Response Testimony), pp. 21-22.
[134] Hr. Ex. 1204 (CEO Response Testimony), p. 22.
[135] Hr. Ex. 1204 (CEO Response Testimony), pp. 26-27.

106. WRA similarly recommends that the Commission approve the Plains End PPA extension as a replacement for Bid 0235 instead of Bid 1000.[136] WRA raises significant concerns about the Company's thermal proposals but notes that due to the nature of this filing and associated procedural schedule, the Commission and parties are unable to effectively investigate the Company's claims regarding resource adequacy issues. According to WRA, there are significant differences in the Company's capacity position if it is viewed through the lens of the currently approved ELCC and PRM conventions, as compared to the Company's new and unvetted methodologies.[137] WRA characterizes the issues as follows: "should the Commission approve the acquisition of additional thermal capacity to address resource adequacy concerns outside the RAP of this proceeding, that are based on ELCC and PRM methodologies that have not yet been litigated."[138]

107. WRA argues that with the updated ELCC/PRM methodologies, Public Service is attempting to justify its proposal to extend the Plains End PPA and pursue a larger self-build thermal bid. WRA observes that one factor influencing the capacity position shortage under updated methodologies appears to be the updated treatment of DR resources. Under current conventions, where DR is treated as a load reduction, DR contributes between 651 MW to 787 MW of load reduction, depending on the year. Under the Company's new methodologies, however, DR is included in the generation category, with capacities ranging from 335 MW to 372 MW. WRA reiterates its claim that the Commission and parties have extremely limited evidence about the factors driving the Company's resource adequacy claims and how these factors manifest in the loads and resources table.[139]

[136] WRA Comments on CEP Delivery, pp. 8-9.
[137] WRA Comments on CEP Delivery, p. 10.
[138] WRA's SOP, pp. 2-3.
[139] WRA Comments on CEP Delivery, p. 14.

108. Staff is more deferential to the Company's obligation to evaluate the reliability of its generating portfolio but ultimately notes the same issues that CEO and WRA raise. In its Response Testimony, Staff acknowledges that the Company retains the obligation to evaluate the reliability of its generating portfolio but states that Staff struggles to see the need for additional thermal capacity in 2028. Staff implores the Company to provide a robust discussion of this issue in its responsive comments and asserts that, without such complete explanation, Staff will not support the acquisition of an additional 200 MW of thermal generation.[140] Conversely, Staff states it will support the Company's position if it can fully demonstrate and explain the reliability concern necessitating the acquisition of the additional 200 MW of thermal capacity.

109. In its SOP, Staff references the load and resources ("L&R") table from Volume 2 of the JTS that Public Service provides in its Reply Comments (JTS Table 2.9-1) as illustrating a significant capacity shortfall through 2033 (e.g., 646 MW in 2025 and 534 MW in 2026). Staff moreover asserts that this L&R Table underestimates the capacity shortfall in that some of the assumed CODs have been pushed back and a solar bid has failed.[141] Nevertheless, Staff stops short of endorsing the Company's proposal.

110. If the Commission determines that the Company has not provided sufficient support for its reliability concerns, Staff states there are two options. First, the Commission could retain the two thermal projects currently in the approved resource portfolio (Bid Nos. 0989 and 0997) and simply add Plains End. Second, the Commission could replace both Bid 0989 and 0997 with Bid 1000 as well as Plains End. Staff's preference is the second option, given that Bid 1000 appears more economical than Bid 0989.[142]

[140] Hr. Ex. 2709 (Staff Response), p. 35.
[141] Staff's SOP, p. 15.
[142] Staff's SOP, p. 15.

111. In its Reply Comments, Public Service asserts that using the Plains End PPA extension as the replacement for Bid 0235 is untenable. Public Service proffers two arguments in support of is position. First, the Company asserts that replacing a new-build thermal asset with the existing Plains End unit does not work from a reliability perspective. Second, the Company argues that forgoing new thermal capacity now is not an option given anticipated resource needs.[143] More bluntly, Public Service states that "[t]he Company will not sign the [Plains End] extension if doing so is conditioned on removing Bid 1000—the best available option to replace Bid 0235—from the portfolio, as some intervenors suggest."[144]

112. Regarding the need for a new-build combustion turbine ("CT") from a reliability perspective, Public Service asserts that it undertook the alternatives analysis the Commission required in its First RRR Decision for the replacement of Bid 0235 and that the preferred result is acquiring Bid 1000 as the replacement for Bid 0235. "Public Service strongly believes that a full portfolio of *new* thermal assets, i.e., at or near 669 MW, is required to continue the energy transition in a reliable manner."[145] The Company asserts an extension of the Plains End unit, which is 20 years old, "is not a substitute for a new CT unit, which the Commission has already approved."[146] Public Service further alleges that "[t]he approval of the acquisition of three new CTs in the Phase II Decision to meet reliability needs is a closed issue," noting that "[n]o party challenged this need on [RRR]."[147] The Company references the Phase II Decision in which the Commission stated that it "cannot simply carve out from a modeled resource portfolio some or all of the firm dispatchable resources that Public Service maintains are necessary for reliability."[148]

[143] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 17-18.
[144] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 26.
[145] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 18 (emphasis in original).
[146] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 21.
[147] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 25.
[148] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 24-25 (quoting Phase II Decision, ¶ 125).

Similarly, Public Services references its earlier arguments in its Response Comments to the 120-Day Report when it stated that "eliminating gas units or taking the shortcut of substituting suboptimal and questionable short-term PPA extensions . . . makes the plan less reliable and risks reliability."[149]

113. On the other hand, Public Service emphasizes that it is not arguing against the Plains End PPA extension. The Company states that Plains End is valuable to the Company from capacity, black start, and transmission support perspectives.[150]

114. As to its argument that foregoing additional thermal capacity is not an option, Public Service argues that a five-year extension of Plains Ends is temporary and creates a hole that will need to be filled when the PPA expires. The Company asserts that it cannot count on any capacity from Plains End after the five-year extension expires, making the PPA extension "an inferior option from a reliability perspective."[151]

115. Referencing its direct case in the JTS Proceeding, Public Service asserts that it has substantial and growing capacity needs due to projected load growth and its revised ELCC and PRM studies.[152] Public Service acknowledges interveners' concerns that the JTS L&R table has not been litigated. Public Service argues, however, that "the appropriate question is not whether the updated load forecasts and ELCC and PRM studies have been approved, but whether it represents the best information available to the Company when making choices in a challenging environment."[153] Referencing the recently-filed JTS Proceeding, the Company states it is "confident of substantial needs for new generation—including both new renewable generation and

[149] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 26 (quoting Public Service's Response Comments to the 120-Day Report, pp. 28-29).
[150] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 26-27.
[151] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 25.
[152] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 27.
[153] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 27.

new firm dispatchable generation—above and beyond anything we have seen in Colorado."[154] Based on this new modeling, Public Service argues that it is prudent to approve the Company's Component 2 portfolio and to extend the Plains End PPA to meet demand in a dynamic environment. Conversely, the Company argues it would be imprudent to simply ignore the best-available information and hope that capacity needs will remain flat.[155]

116. In its SOP, Public Service maintains its position, arguing that it has performed an analysis of all available thermal alternatives and "the Commission has approved the need to build a total of three new [CT] units" in addition to a thermal project in the San Luis Valley.[156] Public Service also states that "Plains End is not a substitute for the new thermal capacity the Commission approved in Phase II."[157]

2. Findings and Conclusions

117. As presented through this CEP Delivery Motion process, Public Service has failed to meet its burden of proof that Bid 1000 is the appropriate replacement for Bid 0235. We therefore deny applying the ERP presumption of prudence under Rule 3617(d) to the Company's proposed replacement for Bid 0235. Instead, the presumption of prudence is limited to the combination of the Plains End PPA extension, Bid 0011, and *either* Bid 1000 or Bid 989 (discussed further below). If the Company insists that the extension of the Plains End PPA, Bid 0011, Bid 0989, *and* Bid 1000 are all necessary for reliability, it can proceed with that option and retain its burden to show in subsequent proceedings the prudency for the incremental thermal capacity (*i.e.*, Bid 1000 or Bid 989) and any associated costs.

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[154] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 18.
[155] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 28.
[156] Public Service's SOP, p. 9.
[157] Public Service's SOP, p. 11.

118. The arguments Public Service puts forth for why the Plains End PPA extension cannot be used to replace Bid 0235 are unpersuasive. Starting with the Company's assertions regarding reliability of Plains End compared to a new-build thermal resource, we note the Company raises no concerns with the location of the Plains End unit compared to the Bid 0235 nor points to any known reliability issues with Plains End. Indeed, Public Service states that the Plains End PPA extension "is valuable to the Company from capacity, black start, and transmission support perspectives…."[158] Instead of raising specific reliability concerns with Plains End, Public Service seems to argue that anything less than three *new* CTs is per se unreliable. For instance, the Company asserts that "[t]he approval of the acquisition of three new CTs in the Phase II Decision to meet reliability needs is a closed issue,"[159] and that "Plains End is not a substitute for the new thermal capacity the Commission approved in Phase II."[160] These statements imply that the Commission found in the Phase II Decision that approximately 650 MW of *new-build* thermal resources is necessary for reliability.

119. We disagree with the Company's characterization of our findings regarding new-build thermal resources. While the thermal resources within the approved portfolio were admittedly all new builds, for reasons unknown to the Commission, the Company did not identify the potential to extend the Plains End PPA as an option until the CEP Delivery Motion. Public Service cannot now argue that failure to include such PPA extensions in the approved portfolio is a finding that such resources are inappropriate. Indeed, existing PPA units *were* included in the approved backup thermal portfolio, and Public Service never contested that these approved backup resources could not replace a new-build resource. In fact, in the First RRR

[158] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 26-27.
[159] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 25.
[160] Public Service's SOP, p. 11.

Decision we rejected Public Service's request to replace Bid 0235 with Bid 1000 because there was no analysis as to whether the existing PPA units such as Bid 1061, Bid 0510, and Bid 0514 could serve as the replacement.[161] Public Service never sought RRR on this point.

120. Contrary to the Company's assertion that the existing Plains End unit cannot be a substitute for the new-build thermal resources initially in the approved portfolio, we see existing PPA units such as Plains End as providing valuable ownership diversity and protection from additional costs. In our Phase II Decision, we noted that Company-owned thermal resources subject ratepayers to the risk of construction and operational cost overruns, decommissioning costs, and the potential that the gas resources will become stranded. We found the approved resource portfolio more desirable than the Company's preferred portfolio in part because the approved portfolio contained a PPA thermal resources, which "reduces the risks that customers will be saddled with future costs associated with Company-owned gas resources."[162]

121. The Company's second argument regarding growing resource adequacy concerns is also unconvincing. We acknowledge the Company's new L&R Table put forth in the JTS shows significant capacity shortfalls through 2033. Ultimately, however, we agree with CEO and WRA that our decisions regarding resource adequacy should be grounded in the evidence that has been litigated in this Proceeding. The resource need projections on which the Phase II Decision relies have been thoroughly vetted throughout this long Proceeding. We are disinclined from adopting the Company's eleventh-hour change in its resource adequacy forecasts as a justification to acquire an additional 200 MW of thermal resources.

[161] First RRR Decision, ¶¶ 77-78.
[162] Phase II Decision, ¶ 108.

122. To be clear, we are not prohibiting the Company from moving forward with the requested incremental thermal resources. We simply conclude that Public Service has not earned a presumption of prudence in this Proceeding, particularly based on the relatively truncated and late-stage process associated with the CEP Delivery Motion. If the Company is convinced it needs additional thermal resources above those approved in this ERP Proceeding, it has other methods of obtaining regulatory certainty before construction, including through a CPCN proceeding. Public Service is ultimately responsible for ensuring reliability. In this vein, we encourage Public Service to continue moving forward with actions it reasonably believes are necessary to ensure the Company has the resources it needs to ensure reliability. This may include, for example, development and permitting work associated with all of its proposed thermal resources.

123. As for the thermal resources for which the Company does enjoy a presumption of prudence, we ultimately provide the Company discretion to pursue either of the two options put forth by Staff. In Option 1, Public Service would enjoy a presumption of prudence for the following thermal resources: the Plains End PPA extension, Bid 0989, Bid 0997, and Bid 0011. In Option 2, Public Service would enjoy a presumption of prudence for the following thermal resources: the Plains End PPA extension, Bid 1000, and Bid 0011.[163]

124. We agree with Staff that Option 2 appears more attractive given the cost advantages of Bid 1000. Moreover, Option 2 avoids the complexities associated with Bid 0989 as discussed below. Nevertheless, we acknowledge there are additional factors that might impact the appropriateness of the two options, such as the timing of when various resources can come online

[163] If, for example, the Company decides to move forward with the Plains End PPA extension, Bid 1000, Bid 0011, *and* Bid 0989, then Bid 0989 would be incremental to Option 2 and thus would not enjoy a presumption of prudence. The other thermal resources would enjoy a presumption of prudence.

and the locational differences of the various resources. Based on the record before us, Public Service is in the best position to determine which option is preferable.

J. Thermal Resource Price Increases

1. Party Positions

125. As part of the CEP Delivery Motion, Public Service seeks the ERP presumption of prudence per Rule 3617(d) that pursuit of the thermal units at the new revised cost levels is prudent. In addition, Public Service asks that the CtC PIM baseline for the utility-owned thermal facilities be adjusted upward to match the new cost estimates.[164]

126. Several intervenors disagree with the Company's request regarding the proposed price increases of the thermal units. For instance, Staff recommends that the Commission not grant the Company the specific price relief, arguing there is simply not enough time and information to ascertain whether the requested relief is reasonable.[165] Staff's strong preference would be for the Company to present its financial analysis in the CPCN proceedings to appropriately allow parties time to examine the Company's estimates, changed circumstances, financial accounting, *etc*. Such CPCN proceedings could appropriately re-establish the individual CtC baselines after careful consideration of the detailed information.[166]

127. In its SOP, Staff argues that the "the Commission must insist upon properly vetting the significantly increased cost projections" and reiterates its recommendation to do so in follow-on CPCN proceedings.[167] Staff argues that Public Service provides little more than the "limited and cursory explanations for the increases in the right-hand column of Hearing

[164] Hr. Ex. 166 (Ihle), pp. 57-58.
[165] Hr. Ex. 2709 (Staff Response), p. 39.
[166] Hr. Ex. 2709 (Staff Response), p. 40.
[167] Staff's SOP, p. 9.

Exhibit 2718HC."[168] Staff further asserts that neither the Commission nor any of the intervenors have had an adequate opportunity to vet the reasons the Company gives for the surges in projected costs. [169]

128. In its Response Testimony, CEO similarly argues that Public Service has not provided detailed information demonstrating which costs have increased, by how much, and why. Without this information, CEO argues, the Commission cannot reasonably determine if the new baseline costs the Company proposes are reasonable. CEO asserts that more detailed cost comparisons and explanations should be provided in future CPCN proceedings, where any prudency requests can be addressed.[170]

129. Interwest recommends that the Commission require Public Service to treat all projects equally in the CEP Delivery Plan to ensure fairness, transparency, and system reliability. According to Interwest, utility-owned projects should be treated in the exact same manner as IPP owned generation, and thermal generation should be treated in the exact same manner as renewable generation. [171]

130. CEC and UCA argue the Commission should retain the project-specific CtC PIMs with no adjustment to the baseline. CEC asserts that modifying the CtC PIM at this juncture would fundamentally disrupt the purpose of the CtC PIM and set a precedent that utilities can simply dodge PIM disincentives if project costs increase. According to CEC, customers should be protected from the cost increases that the IE Report predicted.[172] UCA similarly argues the CtC

[168] Staff's SOP, p. 8.
[169] Staff's SOP, pp. 8-9.
[170] Hr. Ex. 1204 (CEO Response Testimony), pp. 20-21.
[171] Interwest's Comments, pp. 6-7.
[172] CEC's Comments on CEP Delivery, pp. 8-9.

PIM is intended to protect customers against price increases and thus it would be unreasonable to adjust the baseline for a CtC incentive for a price increase.[173]

131. In its Reply Comments, the Company continues to argue that application of Rule 3617(d) and its presumption of prudency to the updated costs for Bid 0989, Bid 1000, and Bid 0011 is appropriate. The Company reasons that it has presented updated pricing with more detail and background than is typically provided in a Phase II process, and this is an ERP where Rule 3617(d) applies to projects receiving approval. Public Service states that a presumption of prudence would provide the Company regulatory certainty to move forward with CPCN filings for these units where the costs can be examined in more detail and a final determination regarding the costs for the project, including the CtC baseline, can be established by the Commission. [174]

132. Nevertheless, the Company acknowledges that several intervenors raise concerns with this concept.[175] If the Commission declines to apply Rule 3617(d), the Company proposes an alternative pathway that it states is responsive to the proposals from Staff and CEO to use the CPCN proceedings reestablish the individual CtC baselines. The Company alternative proposal is for the Commission to make the following findings:

> Finding 1: Prudently incurred costs associated with each of the projects will be eligible for recovery.
>
> Finding 2: Costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and Operational PIM baselines, as determined in the CPCN proceeding.
>
> Finding 3: For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing are—if established by the utility to have cost impacts on the project as delivered compared to the CtC baseline—extraordinary circumstances within the terms of the CtC

[173] Hr. Ex. 509 (UCA Testimony), pp. 27-28.
[174] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 18-19.
[175] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 18.

> PIM, subject to future adjudication by the Commission following development of the project in question. Similarly, although potentially less applicable, the same would be true for the Operational PIM.[176]

133. Public Service states that, in the absence of a Rule 3617(d) application to the updated cost estimates, making the above three findings offers an alternative path forward.[177]

134. In its SOP, Public Service does not discuss the alternative approach of making certain findings prior to CPCNs. Instead, Public Service argues the Commission should move forward with the Company's primary recommendation to approve CtC baseline adjustments consistent with the Company's presentation in the CEP Delivery Motion. The Company asserts that intervenors "have conducted extensive discovery relating to these projects over the last two months, and will have an opportunity for additional review in future proceedings as the projects are brought online."[178]

2. Findings and Conclusions

135. We agree with Staff and CEO that the requested cost increases for the thermal resources should be examined in follow-on CPCN proceedings before deciding whether the incremental costs are entitled to a presumption of prudence or warrant adjustments to the CtC PIM baseline. The Commission finds unpersuasive the Company's arguments that it has presented updated pricing with more detail and background than is typically provided in a Phase II process and thus is entitled to Rule 3617(d)'s presumption of prudence. In a typical Phase II process, there is competitive tension and various resource options. These elements are largely lacking in the context of the CEP Delivery Motion's requested price increases for thermal units. Moreover, it is

[176] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 19.
[177] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 20.
[178] Public Service's SOP, p. 9.

far from clear that Public Service has presented detailed information regarding the requested price increases; Staff's assertions support the opposite conclusion.[179]

136. On the other hand, we disagree with CEC and UCA's suggestions to decide in this Proceeding that no adjustments to the CtC baselines are warranted. Public Service appears to raise legitimate claims that thermal generating equipment has seen significant increases in demand and cost. If established in follow-on CPCN proceedings, such cost increases may warrant adjusting the CtC PIM baseline. Similarly, we decline from adopting at this juncture Interwest's position that thermal resources should be treated the same as renewables.

137. In connection with our decision to evaluate the proposed cost increases in the follow-on CPCN proceedings, we largely agree with Public Service's alternative proposal to make certain findings regarding how such cost increases will be evaluated going forward. The thermal projects that have earned a presumption of prudence in this Proceeding will advance to the CPCNs with this presumption of prudence intact as to the project's as-bid amounts. In the CPCN proceedings, the Commission could determine the incremental costs above the project's as-bid amounts potentially constitute extraordinary circumstances and accordingly adjust both the CtC baseline and the level of costs that carry a presumption of prudence.

138. For clarity, we adopt the Company's three requested findings, with the below modifications. As determined in the respective CPCN proceedings, costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and operational PIM baselines. For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing may potentially constitute extraordinary circumstances within the terms of the CtC PIM (*i.e.*, unforeseen costs that could not have been known at the time the bid was

[179] Staff's SOP, p. 8.

made), subject to future adjudication by the Commission following development of the relevant project. Similarly, although potentially less applicable, the same would be true for the operational PIM. Moreover, prudently incurred costs associated with each of the projects will be eligible for recovery; provided, however, that this in no way impacts the application of the PIMs. For instance, the Company may earn a disincentive under the CtC PIM regardless of whether the underlying costs are imprudent.

K. Bid 0989

1. Party Positions

139. As part of the CEP Delivery Motion, Public Service requests Commission approval to remove the SCR system from Bid 0989.[180] The Company argues the SCR system is not required for environmental permitting and that its removal will result in cost savings and operational advantages.[181]The Company explains that it initially assumed the unit would need an SCR to meet environmental permitting requirements. After further examination, based on permitting requirements, projected capacity factor and operating characteristics, Public Service now maintains that the SCR is not necessary and the unit can be permitted and operated without it. Public Service acknowledges that removing the SCR will likely lower the unit's permitted capacity factor, but the Company states that the lowered capacity factor is still above the range it expects to need for this unit.[182]

140. Public Service states it needs certainty from the Commission on this point in order to commence the air permitting process with the Colorado Department of Public Health and the Environment ("CDPHE"). Public Service asserts that if the Commission defers deciding whether

[180] CEP Delivery Motion, p. 9.
[181] Hr. Ex. 166 (Ihle), p. 75.
[182] Hr. Ex. 166 (Ihle), pp. 75-76.

to remove the SCR, the Company would need to proceed with the SCR for permitting reasons, which would result in "unnecessary costs to customers."[183]

141. In its SOP, Public Service clarifies that the Company is not asking the Commission to either approve anything regarding the permitting of Bid 0989 or approve operational characteristics for Bid 0989. Instead, "the Company simply requests the Commission acknowledge that moving forward without the SCR is permissible in light of the fact that this is a difference from the as-bid configuration."[184]

142. Staff argues the Commission should proceed with caution regarding the removal of the SCR device. Staff notes that the Company's Phase II modeling and bid assumed that an SCR would be installed for this unit. Staff is particularly concerned about the Company's representations regarding the capacity factor at which the unit can operate without the SCR. Staff argues the Commission should find a way forward in which it can quickly vet the Company's cost-reduction claims as well as to verify potential operational concerns associated with removing the SCR. To do this, Staff suggests the Commission direct parties to address the removal of the SCR as part of an operational PIM proceeding.[185]

2. Findings and Conclusions

143. We share Staff's concern that removing the SCR from Bid 0989 might change how Public Service can operate the unit as compared to the Phase II modeling. Public Service has testified, however, that the lowered capacity factor the unit would have without the SCR is not expected to change Public Service's use of the plant and that there is insufficient time to fully

[183] Hr. Ex. 166 (Ihle), p. 76.
[184] Public Service's SOP, p. 10.
[185] Staff's SOP, p. 11; Hr. Ex. 2709 (Staff Response), p. 44.

evaluate the operational changes before Public Service must initiate the permitting process with CDPHE.

144. Based on the Company's representations in testimony, the Commission grants the Company's clarified request in its SOP and acknowledges that moving forward without the SCR is permissible even though doing so is different than the as-bid configuration. Public Service has put forth evidence that removing the SCR will save ratepayers considerable money without interfering in the planned operation of the unit nor the value it is expected to provide ratepayers. CDPHE is tasked with determining the exact impacts that removing the SCR will have on the plant's operations.

145. Nevertheless, if Public Service moves forward with Bid 0989, the issues surrounding the SCR device will need to be more closely examined in the follow-on CPCN proceeding. Public Service's position that the SCR device is unnecessary is based on assumptions regarding how the Company will use the unit. However, there are several uncertainties that might impact the planned use of the unit, including developments with beneficial electrification, large new loads, and the potential entry into a regional market. If such changes alter the calculus for whether the additional operational flexibility granted by use of the SCR device is beneficial, the Commission will scrutinize whether any incremental costs should fall on Public Service's ratepayers.

146. Similarly, we intend to examine in any future CPCN for Bid 0989 whether there should be a mechanism (*e.g.*, a PIM) to ensure the accuracy of the Company's representations regarding the capacity factor of the unit and the role the unit has in the system. One of the primary purposes of thermal units such as Bid 0989 is to help ensure Public Service has the capacity it needs when the system is peaking. If the Company's removal of the SCR device were to impact

the unit's ability to serve its purpose, we would have significant concerns as to whether ratepayers are receiving the intended benefits of the unit and may find the need to guard against this eventuality at the onset of the project.

L. Bid 0011

1. Party Positions

147. Bid 0011 is a 50 MW thermal resource in Alamosa County. The project is being developed and built by Mainspring, but as bid, Public Service would purchase, own, and operate the unit. As with the other thermal units in the approved Alternative Portfolio, Public Service now seeks price flexibility regarding Bid 0011.[186] However, unlike the other thermal units, Bid 0011 claims designation as a "Section 123 resource" as explained in the Phase II Decision.

148. UCA recommends the Commission reject Bid 0011. UCA asserts the life of the Mainspring generators is unknown given that the Mainspring's first commercial units were deployed in 2020. UCA also points to hearing questions that show Mainspring only has about 20 MW of projects in the field.[187] UCA goes on to assert that the price of Bid 0011 is excessive and not competitive with other projects, especially if Bid 0011 fails to qualify for ITC tax benefits. As an alternative, UCA recommends the Commission approve extending the life of the existing Alamosa CTs as a bridge to the JTS.[188] UCA also suggests that some of the Plains End units could be moved to the San Luis Valley to replace the capacity from Bid 011 at a much lower cost.[189]

149. Mainspring submitted testimony that Bid 0011 would reduce CO2 emissions compared to the existing plants in Alamosa County by approximately 59 percent and NOx

[186] Hr. Ex. 166 (Ihle), pp. 27-28; CEP Delivery Motion, p. 9.
[187] UCA's SOP, pp. 6-7.
[188] UCA's SOP, pp. 7-8.
[189] Hr. Ex. 509 (UCA Testimony), pp. 20-21.

emissions by approximately 99 percent on a per MWh basis.[190] Mainspring further asserts that its linear generator technology has the ability to switch between various gaseous fuels, including, but not limited to, natural gas, hydrogen, propane, and biogas. The linear generator uses a low-temperature reaction without a spark or flame, which results in near-zero emissions of nitrogen oxides. [191] With its project's fuel flexibility and ability to seamlessly change fuels without hardware or software updates, Mainspring argues the project does not have stranded asset risk of traditional thermal units. [192]

150. Mainspring notes that when it developed its bid, it did not expect that Public Service would require a third-party engineering study, and the associated cost and schedule impacts were not reflected in the bid. Mainspring argues there are similar requirements related to Bid 0011's status as a Section 123 resource that have forced Mainspring to reasonably deviate from its bid assumptions and associated pricing.[193]

151. In its SOP, Mainspring reiterates the positive attributes of Bid 0011 and notes that due to the plant's new, clean technology, it is a Section 123 resource, to which the Commission must give the "fullest possible consideration to the cost-effective implementation" of the project.[194] Mainspring additionally argues that Bid 0011 will not unreasonably shift risk to ratepayers. Mainspring asserts it has the necessary experience deploying its linear generators, noting the other projects its development team has done and the fact that the Department of Energy recently awarded Mainspring an $87 million grant to build a manufacturing facility to produce its linear generators.[195] Mainspring also states the Commission and parties will be able to evaluate

[190] Hr. Ex. 3001 (Igo Testimony), p. 5.
[191] Hr. Ex. 3000 (Hennessy Testimony), pp. 4-5.
[192] Hr. Ex. 3000 (Hennessy Testimony), p. 8.
[193] Hr. Ex. 3001 (Igo Testimony), pp. 8-9.
[194] Mainspring's SOP, p. 7.
[195] Mainspring's SOP, p. 10.

the build-transfer agreement with Public Service in the CPCN proceeding. According to Mainspring, a core component of the negotiations with Public Service has been reducing risk for ratepayers. Mainspring further notes that it has made substantial investments in the project that will not be recoverable if the Commission ultimately does not approve Public Service's acquisition of Bid-0011.[196]

152. In addition, Mainspring argues that advancing Bid 0011 is the best available option to meet the needs of the San Luis Valley. If the Commission removes Bid 0011 in place of other options that were not competitively bid, Mainspring argues it would undermine the entire Phase II process and potentially chill future competitive solicitations in Colorado. Such a result would also arguably violate Commission Rule 3605(h)(II)(A), which provides that in an ERP proceeding, a Phase II decision "shall establish the *final* cost-effective resource plan."[197] Mainspring specifically critiques UCA's recommendation to move some of the Plains End units to the San Luis Valley as a replacement for Bid 0011. Mainspring asserts there is no analysis on the feasibility of this option and, because Plains End will emit more emissions than the linear generator, such a move would be contrary to the Commissions statutory obligation to account for and help correct the historical inequities faced by disproportionately impacted communities in Colorado.[198] Mainspring also adds the record does not support extending the life of the existing Alamosa CTs.

153. Although Staff initially recommended eliminating Bid 0011 due to its price increase, Staff changed its position after reviewing Mainspring's testimony. In its SOP, Staff now asserts the Commission "should no longer consider dropping Bid No. 0011."[199] Staff recommends the Commission vet the projected cost increases in the CPCN proceeding, arguing that determining

[196] Mainspring's SOP, p. 10.
[197] Mainspring's SOP, p. 13 (emphasis in original).
[198] Mainspring's SOP, pp. 13-14.
[199] Staff's SOP, p. 9.

whether the price increase drivers truly constitute justifiable projected cost increases is an ideal topic for a CPCN proceeding.[200]

154. In Public Service's SOP, the Company continues to recommend moving forward with Bid 0011 at the requested price increase. The Company appreciates Staff's recognition of the importance of Bid 0011. Public Service states that the alternative—life extensions of the existing units at Alamosa—is not preferable, given that they leave the same location-specific capacity hole after 2030.[201]

2. Findings and Conclusions

155. The Commission generally agrees with Public Service, Staff, and Mainspring. Consistent with the other approved thermal resources, Public Service may advance Bid 0011 to the CPCN proceeding, and Rule 3617(d)'s presumption of prudence will remain intact as to the project's as-bid amounts. The Commission will evaluate in the CPCN proceeding whether the incremental costs of the project also warrant a presumption of prudence and whether the CtC PIM baseline for the project should be adjusted as set forth above.

156. We reject UCA's recommendation to use the existing CTs as a bridge until new resources can be acquired in the JTS. The existing thermal resources in Alamosa are aging, and Public Service raised reliability concerns with these plants in the 120-Day Report. UCA's recommendation simply delays when a replacement thermal resource is constructed in Alamosa, with no guarantee that future thermal resources would be more cost effective. We likewise reject UCA's suggestion to move some of the Plains End units to the San Luis Valley. There is insufficient record support for this proposal.

[200] Staff's SOP, p. 10.
[201] Public Service SOP, p. 11.

157. Although Public Service may move forward with Bid 0011 consistent with the other approved thermal resources, we are concerned about the price and size of Bid 0011 and the associated risks to ratepayers. At the same time, we continue to acknowledge the potential fuel flexibility associated with this plant and the potential for benefits in that regard. Accordingly, we direct Public Service to present in the CPCN proceeding as a potential alternative an approach in which the size and costs of the project are reduced. As an example of this alternative option, the Company could consider structuring the build-transfer agreement more as a purchase option and pre-construction development asset with Mainspring. Under such an approach, the Company might have a unilateral option to purchase the project at an agreed upon matrix of prices, with flexibility to adjust the final size of the project. In return for this option, and in addition to the purchase price, the Company could compensate Mainspring for all of its verifiable reasonable third-party development costs at the time the option was signed. Public Service may be able to request accelerated cost recovery of these expenses through the electric commodity adjustment. We encourage the Company to explore and negotiate further this and other potential options regarding Mainspring, with the overarching intent of reducing costs and limiting risks to ratepayers.

M. Purchase of Plains End

1. Party Positions

158. In the CEP Delivery Motion, the Company states that its preferred approach is to extend the Plains End PPA. As a secondary approach, the Company suggests it could pursue purchasing the unit.[202]

[202] Hr. Ex. 166 (Ihle Testimony), p. 115.

159. In their Answer Testimony, Staff and UCA initially both urged the Commission to direct Public Service to purchase Plains End, arguing that purchasing the unit provides substantial cost advantages. UCA in particular characterized the cost-benefit of owning the plant as "massive."[203]

160. In its Reply Comments, however, Public Service argues that requiring the Company to immediately purchase Plains End is not a prudent path. The Company reasons that before purchasing an asset like Plains End, the Company would need to conduct extensive due diligence. Public Service states that it "could not commit to purchasing the unit prior to conducting due diligence without strong and unambiguous assurances that any unforeseen issues … would not be a basis for intervenor disallowance recommendations."[204] If the Company's preferred approach is approved, the Company proposes to report annually, beginning in the March 2025 ERP annual report, on the status of a potential acquisition of Plains End. [205]

161. After reviewing the Company's Reply Comments, UCA and Staff both change positions regarding the purchase of Plains End. In its SOP, Staff now argues against requiring Public Service to purchase Plains End. Staff instead recommends the Commission adopt the Company's preferred approach in which it extends the PPA. In connection with this recommendation, Staff argues the Commission should (1) require Public Service to carry out due diligence regarding the potential acquisition of the unit, and (2) direct the Company to seek Commission approval to purchase or decline from purchasing Plains End in an application filing that contains the Company's due diligence.[206]

[203] Hr. Ex. 2709 (Staff Response), pp. 29-30; Hr. Ex. 509 (UCA Testimony), pp. 16-17.
[204] Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 22.
[205] Public Service's SOP, p. 12.
[206] Staff's SOP, p. 13.

162. UCA similarly recommends that Public Service extend the PPA and perform due diligence on the condition of the plant and the costs for the Company to operate it. Depending on the results of the due diligence, UCA recommends the Company purchase Plains End as soon as possible.[207]

2. Findings and Conclusions

163. We approve the Company's preferred approach of extending the Plains End PPA and then conducting due diligence into a potential acquisition of the unit. To be clear, as argued here, we find that the Company has met its burden and extending the Plains End PPA is entitled to a presumption of prudence.

164. Consistent with the Company's position, Public Service shall report annually, beginning in the March 2025 ERP annual report, on the status of a potential acquisition of Plains End. We also adopt Staff's additional proposal and require Public Service to carry out the due diligence and direct the Company to seek Commission approval to purchase or decline from purchasing Plains End in an application filing that contains the Company's due diligence.

165. While we ultimately agree with Public Service's preferred approach regarding Plains End, the Company's decision to wait until September 2024 to seek regulatory approval regarding Plains End is incredibly frustrating. If the Company would have brought Plains End to the Commission earlier, there might have been additional options for cost savings for ratepayers. There is insufficient information to address that concern raised by parties here. While the Company's preferred approach appears to be the only prudent presented option moving forward based on this record and at this very late stage, our determination only addresses prudency of extension given the record before us. In a subsequent proceeding stakeholders may argue whether

[207] UCA's SOP, p. 2.

Public Service fails to demonstrate the prudency of its decisions to delay seeking regulatory approval regarding Plains End.

N. Alternative Thermal Proposals

1. Party Positions

166. In its Response Testimony, UCA puts forth an alternative thermal proposal that includes Bid 1000 but then adds a another two CTs at an existing gas-fired generator station. UCA argues that adding CTs at this existing site provides important transmission support as an existing gas-fired generator, Cherokee 4, retires. UCA asserts that its thermal proposal provides 1,019 MW of economical thermal capacity.[208]

167. UCA continues to advance its alternative thermal proposal in its SOP, reiterating the importance of adding additional generation at Cherokee. Relatedly, UCA asks that the Commission direct Public Service to delay the Cherokee 4 retirement date by a year. UCA argues that delaying the retirement will improve the reliability of the Company's system and help address the projected capacity shortfall in 2028.[209]

168. CEC offers a similar, but broader, recommendation that the Commission consider extending existing thermal generation capacity as necessary to meet load growth and maintain reliability in the face of lost capacity from withdrawing clean energy projects. CEC asserts that Xcel Energy affiliate Southwestern Public Service Company has turned to extending thermal generating units as it transitions its generation fleet to meet New Mexico's emissions reduction goals. CEC argues the Commission should require Public Service to explore similar opportunities here.[210]

[208] Hr. Ex. 509 (UCA Testimony), pp. 20-21.
[209] UCA's SOP, p. 3.
[210] CEC's Comments on CEP Delivery, p. 8.

169. Another alternative proposal from UCA is that the San Luis Valley should have enough capacity to allow it to be "islanded" if the two transmission lines connecting the San Luis Valley are lost. UCA asks the Commission to direct Public Service to provide summer and winter load and gas-pipeline capacity data for the San Luis Valley, with the load data also showing how much load could be curtailed in case the transmission lines are lost. UCA recommends Public Service provide a plan for how much capacity, including gas, storage, and demand management, is needed to island the San Luis Valley if the transmission lines are lost.[211]

2. Findings and Conclusions

170. The Commission denies UCA's alternative thermal proposal and recommendation to require Public Service to delay the retirement of Cherokee 4. There is insufficient record support for UCA's proposals. We likewise decline CEC's recommendation to require Public Service to explore extending the lives of existing thermal units. Public Service is responsible for reliability and should already be evaluating all potential options to ensure resource adequacy.

171. We also do not support UCA's recommendation to require Public Service in this Proceeding to submit an analysis of the amount of additional capacity that would be necessary to island the San Luis Valley. UCA can always advocate for such an analysis in the JTS if it wishes to do so.

O. Expansion of ISOC Incentives

1. Party Positions

172. Public Service seeks authorization to increase the incentives under the ISOC program to encourage more DR capacity. Public Service argues that expansion of this program is most likely to produce incremental growth in short term DR. The ISOC program uses direct-load

[211] UCA's SOP, pp. 8-9

control and provides a minimum of ten minutes notice to customers prior to controlling the customer's load. Legacy or "grandfathered" customers receive a foundational bill credit of $15.97/kW-mo, but new customers currently receive a bill credit of only $11.27/kW-mo. At this lower incentive, however, Public Service states that only one customer has enrolled in the program since 2019.[212] The Company asks that the Commission increase the "new" program incentive to match the "legacy" incentive of $15.97/kW-mo through 2028.

173. CEO supports increasing the ISOC incentive back to its legacy level on a pilot basis with additional reporting. CEO reasons this will allow the Company to gather information about the willingness of customers to enroll in the ISOC program at the adjusted incentive level. CEO recommend the Commission direct Public Service to provide any learnings and data collected from the pilot both in its 2026 Demand Side Management ("DSM") Strategic Issues proceeding to assess the potential capacity impacts of the ISOC incentive and in its annual DSM Status Report.[213]

174. In its Response Testimony, UCA recommends the Commission reject the Company's proposal to expand the ISOC program, arguing Public Service has not provided enough information to enable the Commission to perform an adequate evaluation of its proposal. UCA specifically asserts Public Service has not provided the additional capacity that could be expected nor provided the additional cost of increasing program incentives.[214]

175. Staff likewise recommends rejecting Public Service's ISOC proposal. Staff argues the ISOC proposal does not belong in this Proceeding. Staff further asserts that since modifying the ISOC program requires changing the Company's interruptible service tariff, an advice letter filing is the proper vehicle for Public Service to seek approval of its ISOC proposal.[215]

[212] Hr. Ex. 166 (Ihle), pp. 118-19.
[213] Hr. Ex. 1204 (CEO Response Testimony), p. 30.
[214] Hr. Ex. 509 (UCA Testimony), p. 24.
[215] Staff's SOP, p. 14 (citing Hr. Tr. November 7, 2024, p. 261).

176. Public Service continues to advocate for its ISOC proposal in its SOP, reiterating that the ISOC proposal would increase incentives for "new" load from participants to match the "legacy" incentive rate of $15.97/kW-mo through 2028. Public Service anticipates that approximately 10 additional MW of ISOC capacity could become available if the legacy pricing is expanded.[216]

177. The Company argues that Staff's suggestion to evaluate the ISOC proposal through a separate advice letter filing could take an additional eight months and would not be an efficient use of the Commission's, the Company's, or intervenors' resources. Public Service argues the proposed change is incremental, the legacy pricing rate has already been vetted and approved, and the change would only be in effect through 2028 when all ISOC pricing can be reevaluated. Public Service also notes it has committed to reporting on the results of its proposal in the ISOC annual reports. Instead of a new advice letter proceeding, Public Service argues the Commission should approve the proposal here and implement it through a compliance advice letter filing.[217]

2. Findings and Conclusions

178. Although the potential for additional DR capacity is attractive and aligned with the Commission's broader intent, we ultimately deny Public Service's ISOC proposal. In this relatively abbreviated process associated with the CEP Delivery Motion, Public Service has not adequately supported its proposal. For instance, there has been insufficient evidence regarding the projected costs and benefits of the Company's proposed modifications to the ISOC program. For these reasons, Public Service will need to present a more fleshed out version of its proposal in a standalone advice letter proceeding.

[216] Public Service's SOP, pp. 15-16.
[217] Public Service's SOP, p. 16.

179. Public Service complains that requiring a separate advice letter proceeding could take an additional eight months. Based on the record in this Proceeding, however, the Company has not established that an eight-month delay in acquiring perhaps an additional 10 MW of capacity warrants deviating from the Commission's standard regulatory process. We direct Public Service to file its ISOC proposal as a separate advice letter as soon as reasonably practicable.

II. ORDER

A. The Commission Orders That:

1. The Motion to Approve Clean Energy Plan ("CEP") Delivery Plan and for Variances from Certain Commission Rules and Decisions filed by Public Service Company of Colorado ("Public Service") on September 6, 2024, is granted, in part, and denied, in part, consistent with the discussion above.

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

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

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING December 16, 2024, and December 20, 2024.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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MEGAN M. GILMAN

TOM PLANT

Commissioners