Decision No. C22-0559

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A-0141E

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

COMMISSION DECISION ADDRESSING APPLICATIONS FOR REHEARING, REARGUMENT, OR RECONSIDERATION OF COMMISSION DECISION NO. C22-0459

Mailed Date: September 21, 2022
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I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Commission addresses the Applications for Rehearing, Reargument, or Reconsideration of Decision No. C22-0459 (RRR Applications) filed on August 23, 2022, by Public Service Company of Colorado (Public Service or Company), Staff of the Colorado Public Utilities Commission (Staff), Colorado Independent Energy Association (CIEA), and Interwest Energy Alliance (Interwest). Consistent with the discussion below, we grant, in part, the RRR Applications from Public Service, Staff, CIEA, and Interwest.

2. Also through this Decision, the Commission grants the Motion for Leave to File a Response to Public Service's RRR Application (Motion to Respond) that Colorado Solar and

Storage Association and the Solar Energy Industries Association (COSSA/SEIA) filed on September 6, 2022.

B. Background

3. As discussed in Decision No. C22-0459, issued August 3, 2022, (the Phase I Decision), Public Service initiated this Proceeding on March 31, 2021, by filing an application for approval of its 2021 electric resource plan (ERP) and clean energy plan (CEP). In accordance with § 40-2-125.5(4), C.R.S., the Company's CEP aims to reduce the Company's carbon dioxide emissions by a target of 80 percent by 2030 as compared to 2005 levels.

4. On November 21, 2021, certain parties filed a Joint Motion to Approve Non-Unanimous Partial Settlement Agreement (Settlement Agreement). The Commission conducted an evidentiary hearing December 8 through 10 and December 13 through 17, 2021 (the December Evidentiary Hearing).

5. On April 26, 2022, the following parties filed a Joint Motion to Accept the Updated Non-unanimous Partial Settlement Agreement (Updated Settlement): Public Service; Staff; the Office of Utility Consumer Advocate (UCA); the Colorado Energy Office; CIEA; Interwest; COSSA/SEIA; the International Brotherhood of Electrical Workers, Local No. 111; Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO; Holy Cross Electric Association, Inc.; Western Resource Advocates (WRA); Walmart Inc.; Natural Resources Defense Council and Sierra Club (collectively, the Conservation Coalition); the City and County of Denver; the Board of County Commissioners of Pueblo County; the City of Pueblo and Board of Water Works of Pueblo; Onward Energy Management; and the Colorado Oil and Gas Association (collectively, the Settling Parties). The Commission held a second evidentiary hearing on May 17, 2022, regarding the Updated Settlement.

6. The Phase I Decision approves, with modifications, the Updated Settlement and Public Service's 2021 ERP. The ERP includes a competitive bidding process for acquiring resources to meet Public Service's projected resource need from 2022 through 2028 and a process for modeling and evaluating the bids. The Phase I Decision further authorizes Public Service to use Phase II of this Proceeding to further implement the requirements for approval of its CEP.

7. In Phase II of this Proceeding, Public Service will issue its Requests for Proposals (RFPs), receive competitive bids and utility-owned proposals, and file a report no later than 120 days after the bids are received, in accordance with Rule 4 *Code of Colorado Regulations* (CCR) 723-3-3613(d) (the 120-Day Report). At the end of Phase II, the Commission will issue a final decision to approve, condition, modify, or reject the utility's preferred cost-effective resource plan per Rule 4 CCR 723-3-3617(c).

8. On August 23, 2022, Public Service, Staff, CIEA, and Interwest—all of which joined the Updated Settlement—filed their RRR Applications.

9. On September 6, 2022, COSSA/SEIA filed the Motion to Respond, arguing that Public Service's RRR Application introduces new facts not in evidence regarding the Inflation Reduction Act (IRA), misrepresents facts in evidence with regard to the expected lives of storage assets, and proposes an entirely new modeling approach for certain storage bids, which causes unforeseen surprise. On September 7, 2022, COSSA/SEIA filed a Correction to the Motion to Respond, clarifying that CIEA responded and supports the Motion to Respond.

10. On September 12, 2022, Public Service filed a response in opposition to COSSA/SEIA's Motion to Respond.

C. Motion to Respond

11. In its Motion to Respond, COSSA/SEIA first argues that Public Service's assertion that the IRA will provide "meaningful tax advantages" is an assertion of fact that is not found in the record of this Proceeding. As support, COSSA/SEIA notes that the IRA was signed into law just one week before Public Service filed its RRR.[1]

12. COSSA/SEIA also asserts that Public Service misrepresents evidence in the record and presents new factual assertions not in the record regarding the expected useful life of storage assets. At the December Evidentiary Hearing, Company witness, Ms. Fowler, stated, "we'd see the useful life [of storage] being closer to 25 [years]."[2] COSSA/SEIA notes that in its RRR Application, Public Service argues that this statement was "hedged at hearing" and "does not represent the opinion of any engineering firm."[3] COSSA/SEIA argues that there is no record evidence Public Service references that supports its claim that Ms. Fowler's statement was hedged, and the assertion that the testimony "does not represent the opinion of any engineering firm" is not a statement based on any record evidence.

13. Lastly, COSSA/SEIA takes issue with Public Service's alternative proposal to permit two new modeling approaches in Phase II if the Commission denies the Company's requests to place the 90/75 limitation on standalone storage and require solar plus storage project to be bid using an energy-only rate. COSSA/SEIA argues that because the Company's alternative proposal for two new modeling approaches were introduced for the first time in RRR, they are new and create "surprise." COSSA/SEIA asserts that it could not have guarded against this surprise because the proposals are not in the record and thus COSSA/SEIA never had a chance to respond to them

[1] COSSA/SEIA Motion to Respond, pp. 3-4.
[2] *Id.* at p. 5 (quoting Hr. Trn. (12/14/2021) at 93:4-8) (internal quotations omitted).
[3] *Id.*

or to introduce evidence as to whether or not they are reasonable, appropriate or based on accurate assumptions.[4]

14. In its Response, Public Service argues that COSSA/SEIA's motion is merely an attempt to garner the last word on key issues for COSSA/SEIA members. Specifically, the Company asserts that it is "hardly novel" to suggest that the extension and expansion of tax credit opportunities in the IRA may lower PPA prices and that it would be nonsensical to ignore the passage of the IRA.[5] Regarding the characterization of Tara Fowler's testimony, Public Service argues that it is clear that Ms. Fowler is not employed by an engineering firm nor is she an electrical engineer, and a good faith dispute over whether her statements at hearing were hedged does not rise to the level that justifies granting COSSA/SEIA's Motion to Respond.[6]

15. Finally, Public Service disputes COSSA/SEIA's assertion that the Company's alternative modeling approaches create surprise. The Company reiterates that it is only requesting these modeling approaches if the Commission denies its primary requests regarding solar plus storage and standalone storage bids. Public Service further asserts that the proposed credit metrics stress test is in-line with the Phase I Decision's acknowledgement that the financial lease and imputed debt issue is a real concern that needs to be considered in this process.[7]

16. Rule 1506(b) of the Rules of Practice and Procedure, 4 CCR 723-1, governs when a party may file a response to a RRR application. Rule 1506(b) states the following:

> No response to an application for RRR may be filed, except upon motion. Any motion for leave to file a response must demonstrate a material misrepresentation of a fact in the record; an incorrect statement or error of law; an attempt to introduce facts not in evidence; accident or surprise, which ordinary prudence could not have guarded against; or newly discovered facts or issues material for the moving party

[4] *Id.* at pp. 5-6.
[5] Public Service Response, p. 4.
[6] *Id.* at pp. 4-5.
[7] *Id.* at p. 5.

which that party could not, with reasonable diligence, have discovered prior to the time the application for RRR was filed.

17. We will grant COSSA/SEIA's Motion to Respond in our discretion considering Rule 1506(b). While granting responses to a RRR application is rare, we find it appropriate to permit response in these limited circumstances on narrow facts and issues raised by COSSA/SEIA given the recently passed IRA and the alternative modeling proposals provided by the Company in RRR.

D. RRR Applications

1. Capacity Payments for Solar Plus Storage and Standalone Storage

a. Summary of Phase I Decision

18. The Phase I Decision directs Public Service to revise its model PPA for solar plus storage, which the Company designed to offer an energy-only rate. The Company argued this energy-only rate was necessary to avoid the creation of a finance lease, which credit rating agencies would construe as debt. Certain intervenors argued that there should be separate energy and capacity resources streams for the solar component and storage component, respectively.[8]

19. The Commission found that Public Service's concerns regarding financial leases and imputed debt are legitimate and "need[] to be considered in this process" but also agreed with intervenors that "energy-only payments for storage will significantly increase bid pricing and customer costs."[9] The Phase I Decision ultimately directs Public Service to follow the New Mexico approach and allow solar plus storage projects to be bid under two separate PPAs (one for solar energy and the other for the storage portion). If capacity is bid for the storage component, the lease term for the storage component is limited to 18 years. This 18-year limit was based on Ms. Fowler's

[8] *See* Phase I Decision, ¶ 332.
[9] *Id.* at ¶ 340.

testimony at the December Evidentiary Hearing that the useful life of storage assets is 25 years and thus an 18-year lease would be less than the 75 percent threshold[10] for creating a capital lease.[11]

20. A similar issue arose regarding the PPA terms for standalone storage projects. As with solar plus storage projects, Public Service argued that standalone storage PPAs could be categorized as finance leases, which could negatively impact the Company's credit ratings. Public Service proposed that the model PPA for standalone storage contain terms that prohibit the Company from being subject to the accounting treatment that results from the classification of a PPA as a finance lease. COSSA/SEIA argued that the Company's proposal to avoid financial leases would require a standalone storage bid to be 20 percent more costly, making it unlikely to be selected.[12]

21. The Phase I Decision again found that the Company's concerns with finance leases were legitimate and should not be ignored but ultimately sided with COSSA/SEIA and prohibited the 90/75 limitation for standalone storage.[13]

b. Public Service RRR Application

22. In its RRR Application, Public Service asks that the Commission reverse the Phase I Decision's rulings regarding both solar plus storage projects and standalone storage. In the alternative, the Company argues that if the Commission maintains these rulings, it should allow two modifications to the Phase II modeling.

[10] The Company asserts that a PPA will likely be categorized as a finance lease if either (1) the present value of the lease payments is 90 percent or more of the fair value of the asset, or (2) if the lease term is 75 percent or more of the estimated life of the asset. (Hrg. Exh. 103 (Brooke Trammell Direct), p. 57). This is referred to as the "90/75 limitation."
[11] Phase I Decision, ¶ 341.
[12] *Id.* at ¶¶ 342-343.
[13] *Id.* at ¶ 346.

23. Public Service first takes issue with the Commission's findings that the energy only rate for solar plus storage projects and the 90/75 limitation on standalone resources will significantly increase the price of bids for these resources. The Company asserts that these findings lack evidentiary support. In fact, Public Service argues that the opposite finding is supported by Rebuttal Testimony of Tara Fowler discussing the results of the Company's most recent solicitation for solar plus storage.[14]

24. Public Service also raises concerns with how allowing a solar plus storage project to bid to into two different RFPs (one for solar the other for storage) will work in practice. The Company states that having two separate PPAs creates numerous issues that the current model PPAs do not contemplate, such as cross defaults and a guarantee for the federal investment tax credit. Public Service argues that the Phase I Decision puts the Company "in the position of unilaterally determining how to facilitate bidding of a single project into two separate RFPs and for two separate PPAs…."[15]

25. Regarding the Commission's specific ruling to limit the lease term for the storage component of solar plus storage projects to 18 years, the Company argues that this 18-year limitation might not prevent a finance lease classification. The Company notes that the useful life of the storage asset could be less than the 25 years that Tara Fowler opined during the December Hearing and might also be ineffective at ensuring that the present value of the capacity payments does not represent substantially all of the fair value of the asset.[16]

26. In the alternative, if the Commission does not reverse one or both of the above decision points, Public Service requests two amendments to the Phase II modeling process. First,

[14] Public Service RRR Application, pp. 4-5.
[15] *Id.* at p. 6.
[16] *Id.* at pp. 6-7.

Public Service requests that the Commission allow the Company to run a credit metrics stress test on any portfolio that includes a solar plus storage project with an energy and capacity payment structure or a standalone storage project that violates the 90/75 limitation. This credit metrics stress test is essentially a repricing sensitivity with a higher equity ratio and higher return on equity (ROE) to reflect potential mitigation of the imputed debt and finance lease issue. Public Service would present the results of this stress test in the form of a second net present value of revenue requirement for the portfolio.[17]

27. Second, to allow for the use of the replacement chain tail modeling methodology, Public Service seeks permission to "fill the gap" between the two components of a hybrid resource with generic resources. For example, if the solar component of a hybrid project had a 20-year life and the storage component lease was restricted to 18 years, the Company would add two years of the generic battery resource to equalize the lives. The Company would then apply the approved tail modeling methodology to the resource (*e.g.*, the replacement chain tail method and/or the annuity tail method).[18]

c. CIEA RRR Application

28. In its RRR Application, CIEA asks that the Commission remove the 18-year term limit for storage components or, in the alternative, direct that the term limit shall be not greater than 20 years.

29. CIEA states that the Commission "correctly modified Public Service's proposals for hybrid solar + storage projects and stand-alone storage projects to allow capacity payments for batteries."[19] CIEA argues, however, that the Commission should remove the 18-year limit on the

[17] *Id.* at p. 8.
[18] *Id.* at pp. 8-9.
[19] CIEA RRR Application, pp. 4-5.

storage component of hybrid projects given that "there is no functional difference between solar + storage projects versus stand-alone storage projects in terms of their PPA terms, project life, or need for financing."[20] CIEA asserts that the 18-year limit could harm the economics of solar plus storage bids from independent power producers (IPPs) and potentially give standalone storage projects a competitive advantage over hybrid projects. As it did throughout the Proceeding, CIEA argues that the Commission already has the tools to address risks to the Company's financial health, and that there is limited evidence that ratepayers receive any benefit from imposing an all-energy payment rate on capacity resources like batteries.[21]

30. Finally, CIEA argues that there is insufficient evidence to establish the actual useful life of a battery storage unit. CIEA acknowledges that Ms. Fowler testified that the useful life of a storage facility is 25 years but notes that she is not an electrical engineer and that, if anything, her testimony supports a 20-year limitation, rather than an 18-year limitation.[22] Thus, CIEA argues in the alternative that if the Commission keeps the term limitation for the storage component of hybrid projects, it should use a 20-year term limit.[23]

d. COSSA/SEIA's Response

31. In its Response, COSSA/SEIA attempts to rebut the Company's assertion that the Commission's finding regarding the 90/75 limitation lacks support. COSSA/SEIA points to the testimony of its own witness, Mr. Luca, and in-hearing testimony from Company witness, Brooke Trammell, as supporting the proposition that the 90/75 limitation will negatively impact IPP standalone storage bids, especially compared to Company-owned bids. Regarding the IRA,

[20] *Id.* at p. 5.
[21] *Id.* at pp. 7-9.
[22] *Id.* at p. 9.
[23] *Id.* at p. 15.

COSSA/SEIA argues that the Company's assertions about the new law are speculative and lack any record evidence.[24]

32. COSSA/SEIA further asserts the Company's arguments regarding the solar plus storage bids that Public Service recently received are irrelevant to the appropriateness of the 90/75 limitation for standalone storage.[25]

33. As with standalone storage bids, COSSA/SEIA argues that the Commission should uphold its finding that the Company's proposal for solar plus storage bids will increase bid pricing and customer costs. COSSA/SEIA further argues Public Service's concerns about dual contracting (*i.e.*, having a separate PPA for both the solar and storage components of hybrid projects) are unfounded. COSSA/SEIA asserts that other utilities have successfully implemented this approach and that Public Service has the resources and contract attorneys necessary to find workable solutions.[26]

34. Regarding the 18-year limit the Phase I Decision places on the storage component of hybrid projects, COSSA/SEIA argues that the Commission should give no weight to the Company's concerns. COSSA/SEIA notes that it supports CIEA's RRR Application on this point and asks the Commission to remove the 18-year limit.[27]

35. As for the two new modeling approaches that the Company requests if the Commission rejects the Company's primary arguments, COSSA/SEIA argues that these new modeling proposals are inappropriate for presentation in an application for RRR. Citing Rule 3604 and Rule 3611, 4 CCR 723-3, COSSA/SEIA asserts that the modeling approaches and assumptions

[24] COSSA/SEIA Motion to Respond, p. 9.
[25] *Id.* at p. 10.
[26] *Id.* at p. 11.
[27] *Id.* at pp. 11-12.

that will be used to evaluate bids must first be vetted during the course of an ERP proceeding. COSSA/SEIA argues that these principles are violated by Public Service's alternative modeling approaches because the Company would introduce modeling assumptions outside the resource plan proceeding and the Company's late filed proposals deprive parties from providing input. COSSA/SEIA argues that the alternative modeling approaches are not even specific enough to allow COSSA/SEIA to provide meaningful input because the Company provides no details as to the "higher" equity ratio or the "higher" ROE it would use in this stress test.[28]

e. Findings and Conclusions

36. We reject the Company's primary positions to place the 90/75 limitation on standalone storage and to require solar plus storage projects to bid energy-only prices.

37. To start, we disagree with the Company's contention regarding the evidentiary support for the proposition that a 90/75 limitation on standalone storage and energy-only bids for hybrid projects will significantly increase the price of bids. COSSA/SEIA witness, Kevin Lucas, testified that the practical impact of the 90/75 limitation is that "third parties whose business model is to own and operate standalone storage will be substantially disadvantaged compared to Company-owned projects that are either self-developed or purchased through a build-own-transfer process."[29] Mr. Lucas goes on to estimate that signing a contract for only 90 percent of the value of the asset and then compressing the payments for the assets into 75 percent of the asset's life "will force the annual cost up by 20 percent compared to a full-length contract for 100 percent of the value of the asset."[30]

[28] *Id.* at pp. 13-14.
[29] Hrg. Exh. 2200 (Kevin Lucas Answer), p. 49.
[30] *Id.*

38. CIEA witness, William Monsen, gave similar testimony regarding the Company's proposed energy-only payment for solar plus storage projects. Mr. Monsen testified that under the Company's energy-only pricing structure, "bid pricing would likely be higher than needed."[31] Mr. Monsen went on to opine that Public Service's proposal "could be viewed as a convenient way to artificially increase the price of IPP bids relative to a solar plus storage facility proposed by Public Service."[32]

39. As a practical matter, we note that energy-only pricing mechanisms could artificially place all of the risk of the solar component of a hybrid project on the storage component. If the solar component malfunctions and receives less revenues, the storage component could also receive less revenue. This structure could likely increase the financing costs of storage assets.[33]

40. In contrast, we find the evidence the Company relies on for its position to be unpersuasive. For instance, Public Service cites Ms. Fowler's Rebuttal Testimony and the description of past instances in which Public Service has used an energy-only payment rate.[34] However, the fact that the Company received numerous bids for solar plus storage projects requiring an energy-only payment and has even executed some of these PPAs does not necessarily mean that the energy-only rate did not make these bids significantly more expensive than they needed to be as compared to providing a separate capacity payment for the storage.

41. Moving to Public Service's concerns regarding how two separate PPAs for a single solar plus storage bid will work in practice, there are different ways to structure the PPAs to allow for two separate revenue streams (*i.e.*, energy payments for the solar component and capacity

[31] Hrg. Exh. 1000 (William Monsen Answer) Rev. 1, pp. 100-01.
[32] *Id.* at p. 101.
[33] *See* Hrg. Trn. (12/14/2021), pp. 95-96.
[34] Public Service RRR Application, p. 5 (citing Hrg. Exh. 133 (Tara Fowler Rebuttal), p. 42).

payments for the storage component) based on different criterial with different tenors. If it is easier, we find it acceptable to have one PPA for solar plus storage projects (rather than following the New Mexico approach with separate PPAs), so long as Public Service allows solar plus storage projects to have these two separate revenue streams.

42. Regarding the Company's concern about revising the PPAs "unilaterally," the Company indicates in its RRR Application that it will be reconvening the Settling Parties to evaluate the impact the IRA has on the model PPAs.[35] We direct Public Service to use this opportunity to work with the Settling Parties on how best to structure PPA language and approach for solar plus storage projects. Again, the key directive is that the resulting contract structure has two separate revenue streams—one for the solar component and the other for the storage component of hybrid resources.

43. Finally, the uncertainties regarding the useful life of storage assets and whether our approach prevents a finance lease classification do not require the Commission to reverse course. We note that there are also uncertainties regarding whether any additional imputed debt from finance lease classifications will actually hinder Public Service's access to low cost capital.[36] Ultimately, these uncertainties do not justify deviating from our decision to allow the storage components of hybrid resources to receive capacity payments but impose an 18-year term limit.

44. Turning to the arguments from CIEA and COSSA/SEIA that we should remove the 18-year term limit on the storage component of solar plus storage projects, we continue to find that the finance lease issue is a legitimate concern. Our current approach in which the storage components of hybrid projects can receive capacity payments but are limited to an 18-year term

[35] *Id.* at p. 25.
[36] *See* CIEA SOP, pp. 30-36.

strikes an appropriate balance between addressing the finance lease concern and allowing IPP solar plus storage bids to be more competitive. Accordingly, we deny the requests to remove the 18-year limit on the storage component of solar plus storage projects and the alternative request to increase the term limit to 20 years.[37]

45. While we deny Public Service's primary RRR requests to place the 90/75 limitation on standalone storage and require solar plus storage projects to bid energy-only rates, we accept Public Service's alternative arguments to allow for two adjustments to the Phase II modeling process (*i.e.*, the credit metrics stress test and using generic resources to "fill the gap" between the solar component and storage component of hybrid resources). Starting with Public Service's proposal to fill the gap between the lives of the solar component and storage component, we find this to be a logical suggestion that will allow for the use of the replacement chain tail modeling methodology as contemplated in the Updated Settlement. This is a more appropriate result than COSSA/SEIA's alternative proposal to eliminate the term limit on the storage component of hybrid resources.

46. As for the credit metrics stress test, given the various assumptions that will underly this stress test and the difficulty of understanding the appropriateness of those assumptions, such a test may be of limited value. Nevertheless, Public Service may include the credit metrics stress test in the 120-Day Report for informational purposes. To be clear, this credit metrics stress test will not dictate the resources the model selects. Moreover, if Public Service presents the credit metrics stress test, the Company must include a detailed explanation of the assumptions and inputs used in the stress test and why the Company concluded that these assumptions and inputs were

[37] Regarding CIEA's argument that the term limit should be increased to 20 years, we find that the current 18-year term limit is better supported in the record. *See* Hrg. Trn. (12/14/2021), p. 91 (Company witness, Ms. Fowler, testifying that "we would be much more comfortable at like 18 years, we'd see the useful life being closer to 25").

appropriate. Parties will be able to comment on the credit metrics stress test during Phase II, which will help the Commission determine how much weight—if any—to accord the credit metrics stress test.

47. With the above parameters for the credit metrics stress test, we are unpersuaded by COSSA/SEIA's arguments that the Commission should prohibit the stress test. COSSA/SEIA's concerns are largely addressed by the fact that the stress test is a repricing sensitivity that will not dictate the resource selection and that the Commission and parties will be able to evaluate and comment on the appropriateness of the assumptions and inputs the stress test uses.

2. Pre-construction Development Assets

a. Summary of Phase I Decision

48. The Phase I Decision notes that there is growing uncertainty due to future climate extremes, supply chain disruptions, inflation, a greater reliance on intermittent resources, and the future costs and performance of clean energy technologies. To mitigate these near-term concerns and create optionality, the Phase I Decision requests that the Company explore acquiring pre-construction development assets for wind, solar, storage, and gas-fired combustion-turbine (CT) resources. These pre-construction development assets would not be built immediately. Instead, the Company would finish development of the pre-construction development assets over time and then potentially bid these projects into the all-source 2024 Just Transition Solicitation (JTS). The Commission encouraged the Company to provide, concurrent with the 120-Day Report, updated contingency planning proposals consistent with Rule 3609(c) that would include any bids for pre-construction development assets. The Phase I Decision contemplates that, after consideration in Phase II if any proposals are included, interim customer funding for these investments could occur through the electric commodity adjustment (ECA). The Phase I Decision

notes that this process would enable such projects to come online in the future in an accelerated manner.[38] We emphasized further that while we encouraged bids for pre-construction development assets given the desirable optionality they could potentially provide as a means to address planning uncertainty, the Company and third parties are not required to submit such bids.[39]

b. Public Service RRR Application

49. In its RRR Application, Public Service seeks clarification regarding the Phase I Decision's directives regarding pre-construction development assets and the Company's proposed implementation approach.

50. For instance, the Company seeks confirmation of the following:

- The Company must solicit proposals for pre-construction development assets in the Phase II competitive solicitation and present any cost-effective options as part of an updated contingency plan under Rule 3609(c) in the 120-Day Report.
- Any pre-construction development assets would not affect resources otherwise acquired to meet the Company's resource needs in the RAP and would be brought back to the Commission for construction approval prior to or during the 2024 JTS process *only if* the contingency plan is triggered by a qualifying event.
- These projects could have in-service dates though end of year 2031 given they would not be approved for construction until the 2024 JTS.
- Any approved pre-construction development assets would be eligible for cost recovery through the ECA, but the cost recovery will be approved in the Phase II decision.

[38] Phase I Decision, ¶¶ 407-08.
[39] *Id.* at ¶ 410.

51. Regarding its proposed implementation approach, Public Service proposes to "reconvene the Settling Parties to discuss the parameters of this solicitation and present them to the Commission for review prior to the commencement of the Phase II competitive solicitation."[40]

c. CIEA and Interwest RRR Applications

52. CIEA and Interwest both oppose the concept of pre-construction development assets and request the Commission remove it from the Phase I Decision entirely.

53. In its RRR Application, CIEA argues that the 2024 JTS makes pre-construction development assets unnecessary. CIEA asserts that with the 2024 JTS scheduled to commence in June 2024, the Commission will have the opportunity to consider whether to invest in new gas units, as well as wind, solar, and storage, as soon as one year after the CEP concludes in 2023. CIEA reasons that this allows near-term flexibility while giving time for current inflationary pressures in the solar supply chain to recede. CIEA also argues that the 2024 JTS "moots" the risk that the late-decade acquisition of CTs will become stranded, as the late-decade resources will be acquired in the 2024 JTS.[41] CIEA argues that "allowing the utility to acquire IPP or its own assets now and obtain cost recovery to hold them will provide a material advantage to Company ownership bids in the [2024 JTS] that does not have to be provided."[42]

54. In the alternative, if the Commission keeps the pre-construction development assets concept, CIEA asks that it be modified to remove wind, solar, and storage technologies. CIEA asserts that there are abundant opportunities in Colorado for renewable projects that do not require

[40] Public Service RRR Application, pp. 25-26. The Company notes that the passage of the IRA triggers the changed circumstances provision of the Updated Settlement and thus the Company will reconvene the Settling Parties for the limited purpose of evaluating the IRA's impacts to the model PPAs, if any. The Company notes that the discussion of "changed circumstances" with the parties can occur in parallel with the Settling Parties' discussion of the development options.
[41] CIEA RRR Application, pp. 11-12.
[42] *Id.* at p. 14.

long lead times and that there will not be a lack of wind, solar, and storage generation capacity to acquire in this Proceeding, including back-up bids that can be called upon if necessary.[43]

55. Finally, CIEA requests clarification from the Phase I Decision's statement that pre-construction development assets could be owned by either the Company or IPPs.[44] CIEA states that it is already a standard IPP business model to own development assets and hold the same without a return or cost recovery until such time as the IPP wins a bid in an RFP or otherwise sells the project.[45]

56. Interwest makes similar arguments in its RRR Application, asserting that with 2024 JTS commencing in June 2024, the development of resources would need to start immediately to be prepared for the bid submission deadline and providing cost recovery would not incentivize additional development activity. Interwest further argues that Public Service is already sufficiently incentivized to begin pre-development activities based on the provisions in the Updated Settlement establishing parameters for utility ownership in the 2024 JTS and the Company's obligation to maintain safe, adequate, and reliable service.[46] Interwest goes on to argue that pre-construction development assets would inhibit competition.[47]

57. Interwest concludes that Public Service is effectively the only developer who could take advantage of the provisions in the Phase I Decision regarding pre-construction development assets, creating a system that gives the Company an unfair competitive advantage regarding both the financing of development and the final bid prices submitted in the 2024 JTS.[48]

[43] *Id.* at p. 13.
[44] *See* Phase I Decision, ¶ 410.
[45] CIEA RRR Application, pp. 14-15.
[46] Interwest RRR Application, pp. 2-4.
[47] *Id.* at pp. 4-5.
[48] *Id.* at p. 5.

58. In the alternative, Interwest requests that if the Commission retains any part of the pre-construction development assets section of the Phase I Decision, the Commission should create additional limitations to retain the competitive nature of the 2024 JTS.[49]

d. Findings and Conclusions

59. Given the RRR Applications of the parties, we will clarify and provide modifications to the pre-construction development assets concept to protect competition while still creating the opportunity for optionality for important capacity assets. As an initial matter, we find that it is in the public interest to have robust and updated contingency planning that includes gas-fired resources such as CTs that are fully permitted (including the air quality permit) and on standby—although not authorized for construction—should they be needed. The record in Phase I seems to indicate this could be as much as 400-500 MW of CTs, but the actual amount will be determined in Phase II after considering the updated modeling and bids. If Public Service's system experiences a capacity shortfall, having a capacity asset that could be approved for construction and come online relatively quickly could be incredibly helpful.

60. To be clear, we grant CIEA's alternative request in its RRR Application; the optionality opportunity provided through pre-construction development assets is limited to gas-fired resources like CTs. Consistent with Public Service's RRR Application, we also clarify that Public Service may solicit proposals in Phase II and present any cost-effective options focused on gas-fired resources as part of its contingency plan required by Rule 4 CCR 723-3-3609(c) in the 120-Day Report. Because these are backup resources, any development assets acquired in Phase II of this Proceeding will not affect the Company's resource need in this Proceeding, and pre-construction development assets included as part of robust contingency planning optionality

[49] *Id.* at p. 6.

will be brought back to the Commission for construction approval only if a qualifying event triggers the contingency plan. Finally, any pre-construction development assets bids must disclose the earliest date that the gas-fired asset could be in service. The in-service dates for these development assets must be within the acquisition period for this Proceeding's solicitation (*i.e.*, through December 31, 2028) but could be as early as 2024. How quickly a development asset could be brought online will be a factor the Commission considers when evaluating whether that particular pre-construction development asset bid is worthwhile.

61. As for the remaining clarifications sought in the RRR Applications, we direct the Company to confer with interested parties, including IPPs, on model PPA language for purposes of the contingency bids and also to discuss any further mutually acceptable and fair approaches for ensuring that we have these backup contingency assets available. As proposed in Public Service's RRR Application, the Company should bring the results of that conferral back to the Commission prior to Phase II.

3. Deferred Tax Asset

a. Summary of Phase I Decision

62. As set forth in the Phase I Decision, Public Service often cannot monetize federal tax credit earnings because the Company does not have sufficient tax appetite. When this occurs, these unused tax credits become a deferred tax asset (DTA) on the Company's books.[50]

63. Public Service proposed to account for any DTA associated with Company-owned resources as a portfolio cost added to the portfolio after modeling to the extent such costs are

[50] Phase I Decision, ¶ 302.

projected to exist. Public Service argued that the Company has "not developed a methodology where these impacts could be disaggregated into a bid-specific standalone impact…."[51]

64. Staff argued that the Company's approach will undercount costs of Company-owned resources and requested that Public Service be ordered to work with Staff to consider and evaluate alternative modeling methods to reflect the Company's DTA costs within the model as resource selections are optimized. Staff further requested that the Company be directed to present a DTA forecast.[52]

65. The Commission agreed with Staff and directed Public Service to submit as a compliance filing a forecast of its DTA levels for the next ten years assuming Company ownership at 20, 30, 40, and 50 percent for all anticipated renewable generation procured through this Proceeding. In addition, the Phase I Decision requires Public Service to confer with Staff prior to Phase II, as outlined in Staff's request. The Phase I Decision emphasizes that the intent should be to find a methodology where DTA costs are assigned at the project level to accurately reflect where such costs originate.

b. Staff RRR Application

66. In Staff's RRR Application, Staff first asks that the Commission require Public Service to include additional components in its DTA forecast. Specifically, Staff requests that the Company's DTA forecasts assume full implementation of all provisions of the IRA. Staff also requests that Public Service include executable workpapers and a detailed narrative explaining all of the Company's assumptions. In addition, Staff asks that the narrative in the DTA forecast explain

[51] Hrg. Exh. 124 (Jon Landrum Rebuttal) Rev. 1, p. 116.
[52] Phase I Decision, ¶ 304

topics such as the interaction between each type of resource ownership and the tax credits available under the IRA.[53]

67. Staff also requests that the Commission clarify the scope of the DTA forecast and specifically the ownership assumptions the Company should use for year 2029 and beyond.[54]

68. Staff's final request relates to the Phase I Decision's directive that Public Service work with Staff to consider and evaluate alternative modeling methods that can evaluate DTAs on a project-specific basis. Staff requests that the Commission create a dispute resolution process, such as a notice of deficiency or request for hearing that could help resolve any impasse between Staff and the Company.[55]

c. Public Service RRR Application

69. The Company requests that the Commission remove the Phase I Decision's requirement for Public Service to forecast its DTA levels. Public Service asserts that the tax credit transferability provisions in the IRA might eliminate the DTA altogether depending on the future market for tax credit transfers. Public Service argues that forecasting DTA levels would have been speculative and uncertain before passage of the IRA, but now the forecast requirement is asking the Company to project a future state that is no longer relevant.[56]

70. Public Service argues in the alternative that if the Commission continues to require this forecast, the Commission should clarify how Public Service should calculate the DTA forecast. Specifically, regarding the directive to assume different ownership levels "for all anticipated renewable generation procured through this Proceeding," the Company asks that the Commission

[53] Staff RRR Application, pp. 2-3.
[54] *Id.* at p. 3.
[55] *Id.* at p. 4.
[56] Public Service RRR Application, p. 21.

confirm that the anticipated renewable generation procured through this Proceeding is the amount of renewables in the preferred portfolio (portfolio SCC 10-RSA).[57]

71. Regarding the Phase I Decision's directive for Public Service to work with Staff to "evaluate alternative modeling methods that can evaluate DTAs on a project-specific basis," Public Service similarly questions whether the Commission should remove this requirement given the passage of the IRA. If the Commission keeps this requirement, the Company seeks clarification that the requirement is to evaluate project-specific DTA modeling approaches to determine if any approach is feasible. The Company seeks clarification that the requirement is to evaluate project-specific DTA modeling approaches as opposed to requiring the use a project-specific DTA modeling approach that currently does not exist.[58]

d. Findings and Conclusions

72. Although Public Service's assertion that the IRA might eliminate the DTA issue could prove to be correct, we will deny Public Service's primary requests to no longer require a compliance filing with its DTA forecast and no longer require conferral with Staff. If Public Service analyzes the issue and concludes that the IRA's tax credit transferability provisions will likely eliminate the DTA, then the Company can explain this in the forecast. In fact, we direct Public Service to supplement the DTA forecast consistent with Staff's RRR Application such that the DTA forecast must: (1) assume full implementation of all provisions of the IRA; (2) include executable workpapers and a detailed narrative explaining all of its assumptions, including its expectation for how the IRA tax provisions impact the Company's ability to monetize tax incentives; and (3) explain the interaction between each resource type and tax credits available

[57] *Id.*
[58] *Id.* at p. 22.

under the IRA and Public Service's assumptions regarding how much of the credit can be monetized over what period.

73. Regarding the questions regarding the scope of the DTA forecast, the Commission grants Public Service's RRR Application on this point and confirms that the forecast should assume the levels of renewable generation under portfolio SCC 10-RSA, which is the preferred portfolio. Thus, as to Staff's specific question about the ownership assumptions the Company should use for year 2029 and beyond, the ownership assumptions should match those included in the preferred portfolio.

74. Moving to the conferral requirement, the Commission confirms that the Company is not required to use a project-level methodology in Phase II modeling that does not exist and might not be feasible. However, if either Staff or Public Service is able to formulate an alternative modeling methodology that can evaluate DTA impacts on a project level, it is still our preference that such project-level methodology be used in Phase II. The conferral shall focus on evaluating project-level methodologies and Staff and Public Service must report to the Commission the results of the conferral and whether such a methodology is feasible. Alternatively, if the conferral reveals that a project-level methodology is infeasible or is unnecessary given the passage of the IRA, Staff and Public Service should describe the same in their report to the Commission.

75. Finally, we reject Staff's request to create a formal dispute resolution process for the DTA conferral. Instead—as discussed above—we direct Public Service and Staff to file in this Proceeding a report setting forth the results of the conferral process. This report could be filed jointly if consensus is reached, or Public Service and Staff could each file a separate report.

4. Application Assigning Costs Between CEP Rider and the RESA

76. The Phase I Decision directs the Company to file an application presenting its methodology for defining and assigning costs related to additional CEP activities as between the CEP rider and the Renewable Energy Standard Adjustment (RESA) "[n]o later than one year in advance of beginning to recover costs attributable to the CEP rider."[59] The Phase I Decision states that this additional proceeding will allow for more robust and concrete vetting of Public Service's accounting.

77. Public Service states it would like to implement the CEP rider as soon as possible after the Phase II decision in this Proceeding, and no later than January 1, 2024. Given the Phase I Decision's requirement that the required application be filed no later than one year in advance of beginning to recover costs attributable to the CEP rider, the Company notes that it plans to file the application this fall.[60]

78. The Commission clarifies that the Company can initiate the CEP rider prior to filing the required application that presents the Company's methodology for assigning costs related to CEP activities between the CEP rider and RESA. The Phase I Decision does not place a time prohibition on when Public Service begins crediting funds to the CEP rider account. Rather, the Phase I Decision limits when Public Service can start debiting or using funds from the CEP rider.

79. For example, the Company could initiate the CEP rider on January 1, 2024, even if it did not file the required application until the fall of 2023 (after the 120-Day Report). The CEP rider account would begin accumulating funds in 2024, but the Company could not use these funds until a year after it filed the required application, *i.e.,* the fall of 2024.

[59] Phase I Decision, ¶ 149.
[60] Public Service RRR Application, pp. 19-20.

80. While Public Service can implement the CEP rider prior to the required application, the Company has no statutory assurance that the Commission will allow it to use any RESA funds for CEP purposes. As stated in the Phase I Decision: "Section 40-2-125.5(4)(a)(VIII), C.R.S., states that a qualifying retail utility '*may propose* to use up to one-half of the funds collected annually under section 40-2-124 (1)(g), C.R.S., as well as any accrued funds, to recover the incremental cost of clean energy resources and their directly related interconnection facilities,' and [the Commission] treat[s] allocation of those funds as optional until it has been clearly demonstrated to be in the public interest."[61]

5. Deferral of RESA-Related Issues

81. The Phase I Decision defers the following two Renewable Energy Standard Adjustment (RESA) modeling and accounting issues: (1) Public Service's 2021 time-fence proposal, and (2) Public Service's proposal to record incremental costs based on resource categories as opposed to individual resources. The Phase I Decision directs that these RESA-related issues should be resolved in "an appropriate [Renewable Energy Standard (RES)] Plan proceeding."[62]

82. Public Service does not take issue with the deferral of these items, but the Company notes that it has repeated these requests in Proceeding No. 21A-0625EG—a RES Plan proceeding. The Company thus asks that the Commission construe "an appropriate RES Plan proceeding" as the currently pending Proceeding No. 21A-0625EG, arguing that the time-fence and category-average modeling proposals are ripe for adjudication there.[63]

[61] Phase I Decision, ¶ 148 (emphasis in original).
[62] *Id.* at ¶ 142.
[63] Public Service RRR Application, p. 19.

83. We grant Public Service's RRR on this point and confirm that the Commission will evaluate these issues in the currently pending Proceeding No. 21A-0625EG. Waiting until the next RES Plan proceeding could cause unnecessary uncertainty.

6. Planning Reserve Margin

84. The Phase I Decision approves the provisions of the Updated Settlement that commit Public Service to update its planning reserve margin study (PRM) for the 2024 JTS and to survey best practices in other jurisdictions when developing its methodology for the PRM study.[64]

85. The Phase I Decision notes Conservation Coalition's arguments that for the next ERP, Public Service should rely less on reserve margin as a reliability metric, use a cost-benefit analysis to evaluate whether a 1-day-in-10-years loss of load expectation (LOLE) is optimal, conduct its PRM study by modeling all Western Electricity Coordinating Council (WECC) regions, and stop assuming that future market purchases are limited to the amount of market purchases it has historically made.[65]

86. The Phase I Decision directs Public Service "to address the Conservation Coalition's concerns" regarding the PRM study for the 2024 JTS.[66] The Commission states that the 2024 JTS's PRM study "must model all WECC regions—not just immediate neighbors—and shall not limit future market purchases based on historical purchases."[67]

87. In its RRR Application, the Company requests the Commission remove the directives that the PRM study in the 2024 JTS "model all WECC regions" and "not limit future market purchases based on historical purchases." The Company reasons that rather than impose

[64] *See* Updated Settlement, ¶¶ 5, 43.
[65] Phase I Decision, ¶¶ 196-97.
[66] *Id.* at ¶ 200.
[67] *Id.*

specific predetermined requirements on its next PRM study, changes to the next PRM study should be driven by the best practices survey, which Public Service has already commenced. Public Service notes that modeling all WECC regions might or might not be best practice by the time the next PRM study is conducted. In fact, Public Service argues that "initial discussions indicate [that modelling all WECC regions] is not a best practice because it requires a multitude of assumptions that likely outweigh any perceived beneficial value."[68]

88. We grant Public Service's RRR Application, in part, and modify the directive such that Public Service's PRM must model all WECC regions—not just immediate neighbor—and shall not limit future market purchases based on historical purchases, *unless doing so is contrary to best practices*. In addition, we clarify that regardless of whether Public Service adopts Conservation Coalition's proposals in its PRM Study, the Company must expressly address the Conservation Coalition's concerns. In other words, regardless of whether the Company models all WECC regions in its next PRM study, Public Service must evaluate this approach and provide a detailed explanation as to why it did nor did not adopt it. Public Service should do the same for the other concerns listed in the Phase I Decision, including relying less on reserve margin as a reliability metric and using a cost-benefit analysis to evaluate whether a 1-day-in-10-years LOLE is optimal.

89. Given the rapid changes in regional markets, resource adequacy, and transmission resources, the Commission is wary of predetermining in this Proceeding the best PRM methodology for the 2024 JTS. While Public Service cannot ignore Conservation Coalition's concerns, the Company should have the flexibility to use a different method if doing so is best practice.

[68] Public Service RRR Application, p. 16.

7. Generic Resource Costs

90. The Phase I Decision approves Paragraph 2 of the Updated Settlement, which commits the Company to updating the costs for generic resources to the most recent vintage of the National Renewable Energy Laboratory Annual Technology Baseline prior to release of the RFP in Phase II.

91. Public Service seeks Commission approval to have the updated generic resource costs in Phase II reflect the passage of the IRA. The Company argues that this will help ensure the best available information is used to develop the generic resource costs.

92. The Commission approves Public Service's proposal to have the generic resource costs used in Phase II reflect the passage of the IRA. It is important to ensure that the Phase II modeling uses the best available information.

8. Transmission Cost Estimates in 120-Day Report

93. UCA argued that the Company should submit, as part of its 120-Day Report, project level estimates of transmission cost upgrades rather than portfolio level upgrade cost estimates. In the Phase I Decision, we found merit in these arguments, reasoning that requiring transmission cost estimates at the project level and following best cost estimate protocols will allow for effective Commission review of the issue. We also noted arguments from UCA that project level estimates are consistent with the requirements placed on the Company in the 2016 ERP process.[69]

94. Public Service seeks clarification that this directive requires the Company to provide transmission costs in a manner similar to previous presentations, where the Company will use its best efforts to categorize general areas of anticipated transmission costs unknown at the

[69] Phase I Decision, ¶¶ 322, 328.

time, with the understanding that additive transmission studies are necessary to determine the full extent of the transmission investment necessary to implement a portfolio.[70]

95. The Commission clarifies that the Company shall provide in the 120-Day Report transmission cost estimates at a similar level of specificity as the Company provided in the 120-Day Report for the 2016 ERP process. As we referenced in the Phase I Decision when denying UCA's request to impose a hard cap on transmission costs in the 120-Day Report, the Company has little time prior to the 120-Day Report to definitively capture the projected transmission requirements for the various portfolios. The Commission recognizes that Public Service will likely need additive transmission studies after Phase II concludes to determine the full extent of the transmission investment necessary to implement a portfolio.

9. Interconnection at Existing Thermal Units

96. The Phase I Decision notes that the transmission assets associated with the Company's generation units need to be made more broadly available for purposes of Phase II modeling to ensure appropriate competitive tension for potential company-owned resource at these sites. We directed the Company "to revise its RFP documents such that IPP projects are eligible to propose interconnecting to the same point of delivery as existing generation units prior to their scheduled retirement with the understanding that Public Service will work to identify least-cost solutions to network upgrades."[71] The Phase I Decision also makes clear that the Commission's ruling is only for purposes of evaluating bids in Phase II and "does not resolve or opine on whether the Company's [Open Access Transmission Tariff (OATT)] in fact prohibits IPPs from using the existing transmission facilities for replacement generation."[72]

[70] Public Service RRR Application, pp. 23-24.
[71] Phase I Decision, ¶ 350.
[72] *Id.* at ¶ 352.

97. In its RRR Application, Public Service asks that the Commission clarify how the Company should evaluate IPP bids that propose to interconnect at the same location as Company-owned existing generators and confirm that the Commission's directives do not require the Company to violate its OATT or FERC requirements when actually processing interconnection requests.[73]

98. The Company explains that—assuming the Company proposes a replacement generator in Phase II—it understands the Phase I Decision as requiring it to evaluate IPP bids that propose to interconnect at the same location as the existing/replacement generator under two scenarios. The first scenario assumes that a Company-owned replacement resource is selected. Under this outcome, Public Service will assign to the IPP bid the transmission upgrade cost required to both interconnect (interconnection service) and deliver (transmission service).[74]

99. The second scenario assumes that the Company-owned replacement resource is not selected and the IPP replacement generator proposes to be in-service before the existing generator is retired. Under this second outcome, Public Service would assign to the IPP bid the upgrade costs for interconnection service that is required to have both the existing generator and the new IPP generator simultaneously interconnect to the transmission system. The IPP generator would not, however, be assigned the upgrade costs for the transmission delivery associated with simultaneously delivering the IPP and the existing generator.[75]

[73] Public Service RRR Application, pp. 9-11.
[74] *Id.* at p. 12.
[75] Under this scenario, the IPP would be modeled such that it would be curtailed on a non-compensable basis whenever there were transmission constraints until the existing generator is retired. This is consistent with the Phase I Decision's provisions: "curtailment credits will not be paid to such an IPP project until the existing coal facility is retired and the IPP can alter its transmission service to firm." Phase I Decision, ¶ 351.

100. Public Service goes on to note that even under this second scenario, the IPP generator may be assigned "some transmission delivery costs since the transmission capacity associated with the existing generator cannot be reassigned to the IPP, but is instead released to the market on an open access basis."[76] Public Service argues that this is appropriate because the IPP would not have priority over earlier-queued interconnection service or transmission service requests.

101. The Commission confirms the Company's understanding and planned implementation of the Phase I Decision's directives on this topic. Our directives regarding interconnection at existing thermal units are for purposes of evaluating bids in Phase II. We reiterate that the Commission is not requiring Public Service to deviate from processing interconnection requests pursuant to the Company's OATT and FERC requirements.

102. Regarding Phase II bid evaluation, we approve the Company's proposal for evaluating IPP bids that propose to interconnect at the same location as an existing/replacement generator. Public Service's plan to evaluate such IPP bids under the two potential scenarios described above will help the Commission and parties better evaluate the cost effectiveness of any replacement generators the Company proposes. We note, however, that the Company must fully set forth this two-scenario evaluation in the 120-Day Report.

10. Performance Incentive Mechanism

103. In general, the Decision adopts the Updated Settlement's proposed performance incentive mechanism (PIM) process. Under this process, the Company will initiate a stakeholder

[76] Public Service RRR Application, p. 12.

process within 15 days after the filing of the 120-Day Report at which the parties will attempt to reach a consensus proposal to bring back to the Commission for review.[77]

104. Consistent with the Settling Parties' request, the Phase I Decision also adopts certain parameters that should govern the resulting PIM(s). Some of these parameters are general (*e.g.*, the Company should have control over factors determining its success or failure), while others are more specific. One of the specific parameters the Phase I Decision identifies is that for any proposed emissions reduction PIM, the "baseline for assessing Public Service's emissions reduction performance should be the cost, level, and timing of expected emissions from the approved Phase II portfolio."[78]

105. The Phase I Decision also directs the parties to use the stakeholder process to craft PIMs addressing certain topics. For example, one of the PIMs the Phase I Decision directs the parties to craft is a demand response (DR) PIM that aims to ensure that the Company is using resources—including DR—that ensure reliability at a lower cost.[79]

106. Public Service argues that the Commission should remove the requirement that the baseline for assessing Public Service's emissions reduction performance should be the cost, level, and timing of expected emissions from the approved Phase II portfolio. The Company argues that pre-determination of the baseline could limit the options available to the participating parties and that the determination of the baseline is best left to the stakeholder process.[80]

107. The Company also asks that the Commission remove the directive for the parties to craft a DR PIM in this Proceeding's stakeholder process. Public Service states that the Company

[77] *See* Phase I Decision, ¶¶ 384, 389.
[78] *Id.* at ¶ 391.
[79] *Id.* at ¶ 192.
[80] Public Service RRR Application, p. 13.

has proposed a DR PIM in its ongoing Demand-Side Management Strategic Issues proceeding (Proceeding No. 22A-0309EG), and that the DR PIM is best addressed in that proceeding. Public Service notes that it has conferred with Staff regarding this issue, and Staff supports addressing a DR PIM in Proceeding No. 22A-0309EG, rather than in this Proceeding.[81]

108. The Commission denies Public Service's request to remove the requirement that the baseline for assessing Public Service's emissions reduction performance should be the cost, level, and timing of expected emissions from the approved Phase II portfolio. The Commission's establishment of a baseline is consistent with the request in the Updated Settlement for the Commission "to identify any parameters with respect to the contested issues it would like to see addressed in the PIM."[82] One of the key contested issues with the Company's proposed emissions reduction PIM is the appropriate baseline. Under the Company's proposed emissions reduction PIM, the baseline is the statutory minimum of 80 percent reduction in emissions below 2005 levels.[83] Certain parties specifically opposed the Company's proposed baseline, reasoning that the Company should not receive a financial incentive for achieving the emissions reductions required by law.[84]

109. Given the record in this Proceeding regarding the appropriate baseline for an emissions reduction PIM, we disagree with Public Service's assertion that this issue is best left to the stakeholder process. In fact, establishing the appropriate baseline will likely help the stakeholders move past a key contested issue, which might help the parties ultimately reach consensus.

[81] *Id.*; *see also* Staff RRR Application, p. 1.
[82] Updated Settlement, ¶ 50.
[83] Hrg. Exh. 103 (Brooke Trammell Direct), pp. 72-79.
[84] Hrg. Exh. 2703 (Eric Haglund Answer), pp. 16-24; Hrg. Exh. 1400 (Noah Long Answer) Rev. 1, pp. 45-49.

110. Conversely, the Commission agrees with Public Service's request—which Staff supports—to remove the directive for the parties to craft a DR PIM in this Proceeding's stakeholder process. Given that this PIM is already at issue in Proceeding No. 22A-0309EG, it makes little sense to require the parties to also craft a DR PIM in this Proceeding. That said, we still view DR as an important component of the ERP process and expect to continue evaluating DR as a resource going forward.

11. Social Cost of Carbon Dispatch

111. The Phase I Decision approves the Updated Settlement's provisions for the use of social cost of carbon (SCC) in the dispatch or commitment of resources in the Public Service system.[85] The Updated Settlement states that "[t]he Company will continue to utilize the SCC in the dispatch or commitment of resources in the Public Service system until it enters an organized market structure of any kind, including, without limitation, an energy imbalance market."[86]

112. Public Service seeks clarification that, if market rules permit it to continue using the SCC in the dispatch or commitment, assuming FERC approval of any such approach, "it is required to continue using the SCC value in the dispatch or commitment of resources and that such use is consistent with the Phase I Decision."[87]

113. The Commission grants Public Service's RRR request, in part, but modifies the Company's interpretation of its requirements to use SCC dispatch. The Updated Settlement requires Public Service to use SCC in the dispatch or commitment of resources until the Company enters an organized market, and during its participation in the market, "the Company will utilize a carbon value in the dispatch of its system consistent with the rules in effect for the organized

[85] Phase I Decision, ¶ 416.
[86] Updated Settlement, ¶ 36.
[87] Public Service RRR Application, p. 24.

market structure."[88] In her written testimony supporting the Settlement Agreement,[89] Company witness Alice Jackson testified as follows:

> We do not want to create asymmetry between Public Service system operations and other market participant operations, which would lead to unintended consequences, such as potentially higher carbon emissions. Rather, upon market entry, the Company would adhere to applicable market rules. If other participants use a carbon value in the dispatch under market rules for the relevant EIM, day-ahead market, RTO, or other structure, then the Company would do so as well, and vice versa.[90]

114. Thus, Public Service is not required to continue using SCC dispatch once it enters a market as long as the market and FERC do not prohibit it from doing so. Rather, per the Updated Settlement, Public Service must use a carbon value in the dispatch of the Company's system that is consistent with the market's rules. In other words, if the market's rules give Public Service discretion as to whether or how to use SCC dispatch, Public Service is not necessarily required to use SCC dispatch. On the other hand, if the market's rules require the use of SCC dispatch, then Public Service would also be required to use SCC dispatch in order to use "a carbon value in the dispatch of its system consistent with the rules in effect for the organized market structure."[91]

12. The Unaweep Pumped Storage Hydropower

115. The Phase I Decision allows Public Service to seek cost recovery of up to $1 million in prudently incurred, investigatory costs associated with the Unaweep Project. The Phase I Decision requires Public Service to seek recovery of this $1 million through ECA quarterly filings where the Commission and other interested parties can evaluate whether such costs were prudently incurred.[92]

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[88] *Id.*
[89] Even though this written testimony pertains to the initial Settlement Agreement and not the Updated Settlement, the Updated Settlement made no modifications to the applicable provisions in Paragraph 36.
[90] Hrg. Exh. 134 (Alice Jackson Settlement Testimony), p. 13.
[91] Updated Settlement, ¶ 36.
[92] Phase I Decision, ¶¶ 431-32.

116. In its RRR Application, Public Service takes issue with the Phase I Decision's language indicating that the Commission and interested parties will evaluate whether costs are prudently incurred in the quarterly ECA process. The Company notes that even though cost recovery itself may occur through the quarterly ECA process, "these applications are filed on less than statutory notice and are not litigated by parties as litigation would defeat the purpose of the timely adjustments needed to the ECA mechanism."[93] The Company argues that cost recovery should occur through the quarterly ECA process, but the prudence of Unaweep Project costs should be adjudicated in an appropriate ECA *annual* prudence review.

117. The Commission grants Public Service's RRR Application on this point, which is a minor change and is consistent with the existing process and structure of the ECA.

13. Water Rights Reporting

118. The Phase I Decision requires the Company to report certain information regarding its water rights, as requested by WRA. The Commission noted that it was persuaded by WRA's arguments about the importance of better understanding the Company's water rights given that these rights impact ratepayers as well as the communities in which Public Service operates facilities.[94]

119. Public Service states in its RRR Application that it does not seek the removal of the water rights reporting requirement. Rather, the Company seeks two clarifications regarding the specifics of what it needs to report.

120. First, the Company seeks confirmation from the Commission on whether its water rights reports can include links to information in the Colorado Department of Water Resources

[93] Public Service RRR Application, p. 15.
[94] Phase I Decision, ¶ 508.

(CDWR) database (*i.e.*, the Colorado's Decision Support System (CDSS)). The Company states that it is willing to craft its water rights reports with or without links to the CDSS. It argues, however, that crafting the water rights reports without links to CDSS will result in "a far more voluminous presentation of hundreds or even thousands of pages of information."[95] Because of this, the Company prefers using links in its water rights reports so that the reports are more manageable for stakeholders.

121. Second, Public Service also seeks confirmation that the Company is not required to report the value of its water rights, as this will require a costly annual analysis of the historic consumptive use. Public Service argues the "determination of 'historic consumptive use' is a nuanced, fact-driven analysis, and is most often the root of contested litigation in Colorado's Water Courts…."[96] Requiring such an analysis upfront and annually for every water right, Public Service asserts, would be "extremely time-consuming and expensive."[97]

122. Regarding the Company's first requested clarification, the Commission confirms that the Company can link to the CDSS database in its water rights reports. We agree with the Company on the benefits of making the reports more manageable for stakeholders and the Commission. In its RRR Application, Public Service states that even under this option it will produce a list of its water assets, which includes general information about the type, quantity, priority, and status of these various assets, and could supplement information from the CDSS database with a short report detailing annual water use data at Colorado generating stations and changes in Company ownership, current use, and future plans around water use based on the best

[95] Public Service RRR Application, p. 17.
[96] *Id.* at p. 18.
[97] *Id.*

available information. These items—in addition to what is currently set forth in the Phase I Decision—are required components of the water rights reports.

123. As for Public Service's second request, we clarify that the Company shall report information reflecting the actual historic use of each water right. In its Answer Testimony, WRA stated that water rights reporting is important to gather sufficient information about the existing use of water at a retiring power plant before any changes are made and to set up a framework to collect information about the ongoing use of water rights as a utility prepares to abandon a plant. WRA concluded that if the Commission does not have the information necessary to determine a water right's value, it will be hard to determine if the Company properly maintained its water rights and if a future proposed transfer is in the public interest.[98] WRA made clear that "the actual historical use of a water right is critical to determining the value of the right."[99]

124. We remain persuaded by this testimony. Given the extreme importance of the water rights that Public Service owns and the Company's transition away from coal fired-power plants, it is important that stakeholders and the Commission are able to monitor whether the Company is properly maintaining the value of its water rights. In order to get a sense of the value of the water rights, it is critical to have information reflecting the actual historical use of the water rights.

125. Given this context, Public Service's argument in its RRR Application that it would be extremely time intensive and expensive to analyze the historic consumptive use of its water rights fails to convince us to reverse course. In WRA's Answer Testimony, WRA expressly requests that the Company include information reflecting "the actual historical use of the water right," on the grounds that this was important to understand whether the Company is appropriately

[98] Hrg. Exh. 2103 (John Cyran Answer), pp. 23-25, 31.
[99] *Id.* at p. 10.

maintaining the value of the water right.[100] In its Rebuttal Testimony, however, it does not appear that the Company argues that reporting the actual historical use of the water right would be expensive or time consuming.[101] Indeed, the Company argues in Rebuttal Testimony that "the reporting suggested by [WRA] is duplicative of current water use reporting which the Company does to comply with the water rights decrees under which it operates and as a part of disclosure of its sustainability record."[102]

126. In sum, the Commission clarifies that the Company must report information reflecting the actual historic use of each water right. While the Company is not required to include in its annual reports a detailed calculation of the market value of its water rights, the Commission and stakeholders must have some sense of the value of the water rights, and information reflecting the actual historic use is critical for this determination. Apart from its annual reporting requirement, at a minimum the Commission expects to receive a calculation of the actual value of the water rights any time there is a proposed change of ownership or change of status.

14. Temporary Economic Shutdown

127. The Phase I Decision states that Public Service may put coal units, including Comanche Unit 3 (Unit 3), into economic shutdown without jeopardizing cost recovery until a subsequent review in a rate case. WRA advocated for this issue, arguing that Unit 3 will be uneconomic to operate in 2028 and 2029, and ratepayers should not be required to continue to pay for power from uneconomic generation resources.[103]

[100] *Id.* at pp. 10, 36.
[101] *See* Hrg. Exh. 123 (Brooke Trammell Rebuttal), pp. 47-48; Hrg. Exh. 132 (Richard Belt Rebuttal), pp. 3-18.
[102] Hrg. Exh. 132 (Richard Belt Rebuttal), p. 7.
[103] Phase I Decision, ¶¶ 509-11.

128. The Company asks the Commission to clarify what the "until a subsequent review in a rate case" may entail. Public Service states that if the Commission "anticipates questioning, or allowing intervenors to question, cost recovery for units that were in temporary economic shutdown, the Company would need to take that into account in its decision-making process."[104]

129. We clarify that the Company can place coal units into economic shutdown and that, by doing so, the Company's cost recovery during the period in which the unit is in temporary economic shutdown is not affected. This is consistent with WRA's position: "A notice of economic shutdown should not impact the utility's cost recovery while the unit is in economic shutdown."[105] The Commission rejects Public Service's implication that the Phase I Decision forecloses the ability of future intervenors or the Commission from investigating cost recovery for plants that were placed in temporary economic shutdown.

II. ORDER

A. The Commission Orders That:

1. The Application for Rehearing, Reargument, or Reconsideration of Decision No. C22-0459 filed by Public Service Company of Colorado (Public Service) on August 23, 2022, is granted, in part, consistent with the discussion above.

2. The Application for Rehearing, Reargument, or Reconsideration filed by Staff of the Colorado Public Utilities Commission on August 23, 2022, is granted, in part, consistent with the discussion above.

3. The Application for Rehearing, Reargument, or Reconsideration filed by the Colorado Independent Energy Association on August 23, 2022, is granted, in part, consistent with the discussion above.

[104] Public Service RRR Application, pp. 22-23.
[105] Hrg. Exh. 2100 (Gwendolyn Farnsworth Answer), pp. 26-27; *see also* WRA SOP, p. 13.

4. The Application for Rehearing, Reargument, or Reconsideration filed by the Interwest Energy Alliance on August 23, 2022, is granted, in part, consistent with the discussion above.

5. The Motion for Leave to File a Response to Public Service's Application for Rehearing, Reargument, or Reconsideration that the Colorado Solar and Storage Association and the Solar Energy Industries Association filed on September 6, 2022, is granted.

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

7. This Decision is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING September 14, 2022.

(S E A L)

THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

ERIC BLANK

JOHN GAVAN

MEGAN M. GILMAN

Commissioners

ATTEST: A TRUE COPY

Doug Dean,
Director