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.

COMMENTS OF NATURAL RESOURCES DEFENSE COUNCIL AND SIERRA CLUB ("CONSERVATION COALITION") ON THE 120-DAY REPORT

November 8, 2023

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INTRODUCTION

Natural Resources Defense Council and Sierra Club (collectively, the "Conservation Coalition") submit these comments on the 120-Day Report filed by Public Service Company of Colorado ("PSCo" or the "Company") in its Phase II electric resource plan ("ERP").[1]

SUMMARY OF RECOMMENDATIONS

Portfolio and bid selection

Approve Option 1 below and defer consideration of new gas because all of the gas in the Company's Preferred Plan was manually forced into the portfolio rather than selected by the model without inappropriate constraints; these manual choices were based on new modeling inputs and methods that the Company developed in Phase II that were never presented to or approved by the Commission in Phase I; and because the Independent Evaluator's Report showed that the model selected only 400 MW of new gas when the Company conducted modeling runs at the IE's request.

- **Option 1**:
    - Approve the renewable and battery storage resources in the Lower Dispatchable Plan;
    - Reject the Hayden biomass project and approve instead the solar project selected instead of the Hayden project (Bid 0474);
    - Do not approve any new gas resources at this time; defer consideration of new gas either to further proceedings in this case or the Just Transition Plan filed by June 1, 2024; resolve the problems with the Company's modeling; and instruct the Company to provide more information on the ability to extend the lives of the gas CTs otherwise expected to exit the Company's system.

    or, if the Commission rejects Option 1, select Option 2 below

- **Option 2**:
    - Approve the Lower Dispatchable Plan without the Hayden biomass project and with the solar bid that replaces the Hayden biomass project (Bid 0474);
    - Do not approve the new gas back-up bid for potential new load and defer selection of new gas resources that might be needed for potential new load to the Just Transition Plan filed by June 1, 2024.

Sideboards on any new gas approved here

- Order that the depreciable life for any new gas resources approved in this case should be no longer than 20 years (and in no event beyond 2050) and may need to be shortened further in future proceedings;
- Require the Company's shareholders to bear 100% of the future costs that have not been included in Xcel's Phase II modeling and that are necessary to enable new gas plants to operate beyond 20 years (or past 2050) by converting new gas resources to burn 100% hydrogen;

[1] These comments were prepared with the assistance of the Applied Economics Clinic, Strategen Consulting, and Telos Energy.

- To the extent that the Company plans to blend increasing amounts of hydrogen at new gas units, require the Company to procure "green hydrogen," defined as hydrogen produced through methods that emit less than 0.45kg CO_2e per kilogram of hydrogen.

<u>Violations of Phase I Updated Settlement and Phase I Commission Order</u>

- Find that the Company's modeling violates the Updated Settlement Agreement and the Commission's Order in Phase I by using the following modeling assumptions and methodologies that were not vetted or approved in Phase I:
    - A new "Reliability Rubric" modeling methodology;
    - A new "portfolio ELCC test" run in PLEXOS;
    - New reliability metrics for determining when a portfolio passes or fails weather sensitivities; and
    - New hot summer and cold winter weather events.
- Instruct the Company that the Commission will not tolerate the Company deviating from the modeling methodology and assumptions approved in a Phase I Order unless the Company has obtained prior approval from the Commission.

<u>Instructions for the Company's June 1, 2024 Resource Plan ("Just Transition Plan")</u>

To ensure that the Company fixes the problems with this Phase II filing on a going-forward basis, the Commission should instruct the Company to do the following in the resource plan filing it must make by June 1, 2024 (i.e., the "Just Transition Plan" filing):

- <u>Provide all relevant data to intervenors</u>
    - In both Phase I and Phase II, the Company should provide intervenors with all input and output files from all modeling the Company conducts, including modeling databases in their native software formats;
    - The Company should provide written explanations for all manual adjustments it makes to portfolios developed by the models, and document how all manual adjustments affected the cost and composition of portfolios;
- <u>All modeling assumptions and methods to be vetted and approved by the Commission</u>
    - The Company should not use any reliability metrics and/or methodologies in Phase II unless they have been previously approved by the Commission either in its Phase I order or a subsequent order;
- <u>Improve reliability analyses</u>
    - Conduct capacity accreditation studies and planning reserve studies in the same software tool and database to ensure consistency;
    - Apply similar capacity accreditation techniques to all resources, including gas and coal plants rather than assuming installed capacity or unforced capacity for purposes of the PRM;
    - Build all portfolios in both Phase I and II to the same minimum level of reliability;
    - Evaluate the marginal ELCC of battery storage resources at increasing levels of renewable adoption to ensure portfolio effects are captured in the initial ELCC curves;
    - Conduct a reliability back-check of resulting EnCompass portfolios to ensure they meet a 1-day-in-10-year LOLE (or alternative) reliability criterion, rather than rely on PRM or ELCC adjustments;

    - Clearly identify when, and to what extent, resources are selected outside of the capacity expansion process to meet reliability needs;
    - Conduct the PRM and ELCC studies using the same model and the same inputs.
- Improve analyses regarding potential new gas resources
    - Provide more information in the next Phase I filing on the engineering considerations and costs of short-term life extensions of existing gas plants on the Company's system;
    - Model all future costs to make new gas units zero-emissions such that if the Company continues to assume that gas units eventually burn 100% hydrogen, the Company includes costs for:
        - Converting/modifying turbines not capable of burning 100% hydrogen;
        - Converting/modifying any other infrastructure that is not compatible with burning 100% hydrogen;
        - Fuel costs for 100% emission-free hydrogen (i.e., "green hydrogen");
        - Dedicated pipelines to transport hydrogen to the Company's power plants;
        - Hydrogen storage facilities (as needed).

Reduce the Burden Regarding CPCN Proceedings that Result from this Proceeding

Given the large number of CPCN applications that may result from the Commission's Phase II decision, the Commission should take steps to reduce the burden on parties and the Commission from having to litigate so many CPCN applications. The Commission should consider:

- Instructing the Company to confer with stakeholders and file a report containing either a consensus proposal for how to address the large number of CPCN applications or the parties' various proposals if no consensus is reached; and then the Commission would issue an Order regarding how to handle the large number of CPCN proceedings.
  or
- Ordering that the Commission will reduce the total number of CPCN proceedings by consolidating the Company's CPCN applications according to some criterion or criteria, such as expected online date, or by technology type (e.g., there would be a single proceeding for all of the Company's CPCN applications for wind resources, a separate proceeding for all of the Company's CPCN applications for solar resources, etc.).

COMMENTS

I. PROVISIONS OF THE UPDATED SETTLEMENT IMPROVED ASPECTS OF THE PHASE II PORTFOLIOS RELATIVE TO PHASE I.

Regardless of which portfolio the Commission approves, the final plan will be an historic deployment of renewables and battery storage toward the State's decarbonization goals. This positions the Company to access unprecedented levels of federal funding available through the Inflation Reduction Act and other federal programs. We are pleased that all of the portfolios in the 120-Day Report have greater amounts of renewables and storage, and smaller amounts of gas, relative to their comparable portfolios in the Company's Phase I modeling. For example, the Company's preferred portfolio in the 120-Day Report has significantly more renewables and battery storage, and less new gas, relative to its preferred portfolio in Phase I.

One of the reasons that the Phase II portfolios have less new gas and more batteries than the Phase I portfolios is that, after many intervenors in Phase I criticized the Company's ELCC values for new batteries (both standalone battery storage and the storage component of hybrid resources), the Updated Settlement in Phase I obligated the Company to conduct a ELCC study for use in Phase II. The new study contained higher ELCC values for batteries than the Company used in Phase I.[2] This underscores the importance of the Phase I litigated process and of intervenors and the Commission in Phase I fully vetting and approving the inputs and assumptions to be used in Phase II.

Unfortunately, the Company's modeling deviated in several ways from the Updated Settlement Agreement and the Commission's Phase I Order and used a number of modeling assumptions and methods that were not presented to and approved by the Commission in Phase I. The remainder of these comments addresses these aspects of the Phase II portfolios, and areas in which we disagree with the Company's preferred portfolio. However, we want to reiterate that while the areas of disagreement are important, they should not overshadow the fact that we support many, if not most, of the Company's proposals to invest in transmission, wind, solar, and storage.

II. THE COMPANY MADE SIGNIFICANT, MANUAL ADJUSTMENTS TO THE MODELING THAT FORCED NEW GAS INTO PORTFOLIOS.

The utility-scale resources at issue in this proceeding are large, long-lived assets. Collectively, the resources at issue here represent billions of dollars in assets that are intended to last for decades—in some cases, for 40 years or longer. With respect to new gas plants in particular, the Company has proposed 628 MW of new gas in its preferred portfolio. Those new gas units would cost approximately $1 billion,[3] and the Company's modeling assumes they would have useful lives of at least 25 years. If the Commission makes the wrong decision to approve a gas plant that the Company expects to last for decades, there is no easy and cheap way to undo that decision.

Thus, the decision about the amount of new gas to authorize the Company to procure has very large stakes. We cannot support the Company's proposed acquisition of 628 MW of new gas when <u>all</u> of that new gas is the result of manually forcing in new gas, rather than the model selecting new gas as the most economic resource. Moreover, we strongly oppose the Company's decision to develop modeling inputs and methods for the first time in Phase II, without ever allowing the parties to review those input and methods in Phase I, and without obtaining Commission approval of those inputs and methods in Phase I. The Company's actions here violate the terms of the Updated Settlement Agreement and the Commission's merits Order in Phase I. The Company's actions also undermine the entire purpose of having a litigated Phase I proceeding, which is to allow parties to vet the Company's proposed modeling inputs and methods, and for the Commission's Phase I Order to dictate how the Company will conduct modeling in Phase I.

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[2] 120-Day Report, Appendix D at 14-15.

[3] *See* 120-Day Report at 126 (Table 34) (showing that Bid 1000, a gas plant included in the Company's Preferred Plan, has a PVRR of $607 million). Given that the Preferred Plan proposes two additional gas plants (Bids 986 and 989), and given the size of those two other gas plants, the total PVRR of the three gas plants in the Company's Preferred Plan exceeds $1 billion. This can be confirmed through examination of the cost data in Appendix P.

A. The Company Used Reliability Metrics, Methodologies, and Assumptions in Phase II that the Commission Never Approved in its Phase I Order.

The outcome of the portfolio modeling in the 120-Day Report was heavily influenced by several interrelated modeling decisions that the Company made during Phase II and that were never presented to–much less approved by–the Commission in Phase I.[4]

First, after running portfolios through the summer and winter extreme weather event sensitivities, the Company decided what level of unserved energy and ancillary services violations would cause the portfolio to "fail" the sensitivity.[5] We are not aware of any place in the 120-Day Report that explains what amount of unserved energy and/or ancillary service violations caused the Company to conclude that a portfolio "fails" these sensitivities. Nor are we aware of the Company having proposed (or the Commission having approved) any such metrics in Phase I. In addition, in Phase I, the Company never proposed to revise the Phase II portfolios if they "failed" the extreme weather event sensitivities–and the Updated Settlement does not specify that the Company should do this either.

Second, after the Company judged that portfolios had "failed" the weather sensitivities (according to some unspecified metric), the Company made a series of manual adjustments to portfolios pursuant to a "Reliability Rubric." By "manual," we mean that the Company forced into a portfolio specific amounts of specific resources that had not been selected by the model through optimization during capacity expansion. The Company forced in a certain amount of battery storage and a certain amount of new gas resources.[6] "The capacity amount of natural gas projects selected in the base plan was set as a minimum constraint, along with an additional 400 MW of gas."[7]

Third, once the Company had manually altered portfolios such that they "passed" the summer and winter sensitivities according to some undisclosed and unapproved metric, the Company ran the portfolio through PLEXOS to meet a "portfolio ELCC" test.[8] The Company made further manual adjustments to portfolios to meet its portfolio ELCC metric. The Company did not propose this "portfolio ELCC test" in Phase I and the Commission did not approve in its Phase I Order the use of a "portfolio ELCC test" in Phase II. In addition, while the Commission directed the Company to conduct a third-party ELCC analysis ("Astrape"), the Company again

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[4] The Company made further changes to the modeling in Phase II beyond what is highlighted below. While the Updated Settlement directed the Company to use the "extreme summer" weather event that the Commission had ordered the Company to model in supplemental direct in Phase I, the Company developed a different extreme summer weather event for use in Phase II. 120-Day Report at 77. We agree with the Company that the summer event it modeled in Phase II is much more realistic than the summer event the Commission asked the Company to model in supplemental direct testimony in Phase I. Nonetheless, the Company could and should have proposed to parties and the Commission this change prior to using this new summer event in the 120-Day Report.

In addition, while the Updated Settlement in Phase I specifies that the Company would use the summer weather event from the Company's supplemental direct testimony, and winter Storm Uri, as sensitivities, the Company provided very little information in the 120-Day Report about how exactly it conducted these sensitivities. The Company only provides a single paragraph explaining how these extreme weather events were constructed. *Id.* This single paragraph is insufficient for stakeholders and the Commission to evaluate such important modeling choices as the extreme weather sensitivities.

[5] *Id.* at 72.

[6] *Id.* at 78.

[7] *Id.*; *see also id.* at 80.

[8] *Id.* at 74, 81-82.

reverted to PLEXOS to conduct the portfolio ELCC test. While the specific modeling tool is not a concern, consistency between the study phases is.

When intervenors such as UCA and the Conservation Coalition recommended that the Company run the EnCompass portfolio results through another model to ensure reliability,[9] the Company vociferously opposed that proposal.[10] Indeed, at the Company's insistence, the Updated Settlement states that the Company would not do in Phase II the kind of "round-trip modeling"[11] that the Company did in PLEXOS here. Inexplicably, the Company decided at some point in Phase II that it would do round-trip modeling, and adopted a portfolio ELCC test use in PLEXOS as part of its "Reliability Rubric"--without ever having run its proposal by the Commission in Phase I.

Equally troubling is the Company's failure to show, in the 120-Day Report, exactly how the Company's manual adjustments affected the composition and cost of each portfolio. There is no table or figure in the 120-Day Report documenting the effects of the Company's manual adjustments for each portfolio. We have reviewed all the appendices to the 120-Day Report, and have been unable to find any information on the cost of the base EnCompass portfolios before the Company made its manual adjustments, and the cost impact of the manual adjustments made in EnCompass and PLEXOS. The Company framed the additional gas turbines that were manually forced into the portfolios as an insurance policy for customers. Building on this analogy, the Company should have informed the public of the insurance premium that customers must pay for that protection (i.e., the difference in cost between the portfolios before and after the manual adjustments).

We have found only one place in which the Company provided information on the composition of some portfolios before the manual adjustments were made.[12] But the Company provides this "before" and "after" information for only some portfolios. If the Company is going to make manual adjustments, it is critical that the parties and the Commission understand exactly how the manual adjustments affected the composition of each portfolio–yet the Company failed to provide this information for all portfolios.[13] The very limited information the Company provided is insufficient to understand the precise reliability issues that the Company claims it was solving for (e.g., in the weather sensitivities, the Company does not provide information about when the hours of unserved energy occurred, etc.).[14]

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[9] H'rg. Exh.1403, Rev. 1 (Stenclik Answer Testimony) at 7, 18, 41.

[10] Hearing Exhibit 1403, Attachment DS-3 (Company's Response to Discovery Request CC2-8) ("The Company did not conduct a post-EnCompass "Portfolio ELCC Review" for the Phase I portfolios as is contemplated for Phase II bid evaluations and as described on Page 334 of Volume 2. The Company did not feel that conducting such a review on Phase I portfolios created using generic resources would provide any useful information.").

[11] H'rg Exh. 156 at ¶ 25.

[12] *See* 120-Day Report, Appendix S at 21-23, 41-43.

[13] For all portfolios, the Company should have provided (1) the raw EnCompass output, (2) the portfolio that resulted from the EnCompass extreme weather sensitivity, and (3) ultimately the final portfolio after the ELCC PLEXOS simulations were completed. This would show the incremental adjustments to the portfolio that were made to ensure portfolios pass the reliability test versus what was selected based on economics and emissions considerations in EnCompass.

[14] For example, Table 19 in the 120-Day Report provides the reliability failures under the extreme summer results, which were not used for the development of the portfolios, but no such table is provided for the originally "unreliable" portfolios, a table that would be much more relevant for our review. Combining this lack of information with the statement that 400 MW were added "if any of these conditions existed" raises additional concerns as to whether such an adjustment was required for a portfolio that for example exhibited a minimal level of ancillary service violations. This deprives the parties and the Commission of critical information on exactly how the Company's manual adjustments altered the portfolios presented in the 120-Day Report.

Fourth, the Company used a "local reliability" criterion[15] to develop a single portfolio–its Preferred Portfolio–but failed to ensure that other portfolios met this "local reliability" criterion. The Company then uses "local reliability" as a purported justification for its Preferred Portfolio, despite never having presented this criterion in Phase I and despite the Company having made the deliberate decision to not build all the portfolios to meet this same local reliability metric.

B. The Company's Modeling is Inconsistent with the Commission's Phase I Order and the Purpose of Phase I.

The purpose of Phase I is for the Commission to approve the specific assumptions and methods that the Company will use to model bids in Phase II.[16] In this proceeding, the Commission's Phase I merits Order held that "[t]he 120-Day Report will present an evaluation of all proposed resources, <u>based on the criteria established in the Phase I decision.</u>"[17] However, the Company's modeling presented in the 120-Day Report is based on criteria that were <u>not</u> approved in the Commission's Phase I decision, and therefore the Company has violated the Phase I Order and the Commission's rules. The Company has acted as if it has the unilateral authority to use whatever assumptions, metrics, and methodologies it sees fit in Phase II–regardless of whether the Commission has approved their use in its Phase I Order.

In addition to depriving the Commission of the opportunity to weigh in on whether the Company's modeling choices are reasonable, the Company has shut stakeholders out of the process. If, during Phase I, the Company had ever proposed to use the new modeling assumptions and methods that it developed in Phase II, the Conservation Coalition would have submitted discovery to better understand those modeling proposals, and, based on what has been presented here, would have submitted testimony criticizing the modeling proposals. The Company never gave any party the opportunity to weigh in on the modeling decisions mentioned above before they were presented as a done deal in the 120-Day Report. This is simply not how the ERP process is supposed to work.

The ways in which the Company deviated from the Settlement and the Phase I Order can be understood by examining how the Company treated sensitivities other than the extreme weather sensitivities. For example, the Updated Settlement called for the Company to model portfolios under sensitivities that altered the assumed gas prices (both low and high gas prices). With respect to the low and high gas price sensitivities, the Company followed the Settlement and Phase I Order by providing the PVRR of the portfolios under the low and high gas price sensitivities. But in Phase II, the Company did not invent a new cost threshold according to which it deemed a portfolio to have "failed" the gas price sensitivities if it had a PVRR above a certain amount, and then, if the portfolio "failed" the sensitivity, alter its composition until it "passed." Instead, the Company simply showed how the PVRR of the portfolios changed under the gas sensitivities, leaving the parties and the Commission to use that information as they see fit.

The Company may respond that it faced problems in the Phase II modeling, and that it took measures it deemed reasonable to address unanticipated modeling problems. However, this

[15] 120-Day Report at 16, 19, 34, 37.
[16] *E.g.*, Decision No. 22-0459 at ¶ 7 (stating that that the Phase I ERP "describes in detail how the utility will evaluate the bids and proposals submitted in response to Requests for Proposals (RFPs), including the inputs and assumptions to its bid evaluation models . . ."),
[17] *Id.* at ¶ 10.

specific reliability-related "problem" that the "Reliability Rubric" was invented to address is a problem of the Company's own making. It is entirely predictable that portfolios would fail an extreme weather test when the Company did not include the data from those extreme weather events in its base modeling runs, because the Company did not set up the runs to directly address such events. If the Company had treated the weather sensitivities as sensitivities, as they were intended, the Company would not have needed to create the "Reliability Rubric." If the Company had wanted to treat the weather sensitivities as binding constraints that a portfolio must "pass," the Company should have made that proposal in Phase I by proposing the specific criteria it would use to determine whether a portfolio "passed" the sensitivity, and then proposing the steps it would take to modify a portfolio that does not initially pass the sensitivity. The Company failed to do that in Phase I, and instead blindsided the parties by adopting these methods for the first time in Phase II.

In the 120-Day Report, the Company also implies that the "Reliability Rubric" is reasonable because it was "created with the IE."[18] To begin, the IE Report contradicts the Company's claim by stating that the "[t]he IE reviewed the reliability rubric but did not have a significant role in its development and found it to be an acceptable path forward."[19] Thus, while the IE did agree with the "Reliability Rubric," the IE appears to have reviewed the Rubric rather than created it with the Company. Even if the IE had played a role in creating the Rubric, that would not provide any additional credibility to the Rubric. As the name suggests, the role of the IE is to evaluate the Company's actions in Phase II—not to create new modeling inputs and methods. The Commission's Phase I Order clarified the role of the IE, and the Order did not give the Company or the IE the authority to create new modeling methods in Phase II.[20]

Moreover, the IE expressed significant reservations about the Reliability Rubric and the Company's decision to manually force gas resources into portfolios. "[T]he IE was concerned about PSCo's approach of simply forcing in gas as part of the reliability rubric. While the IE believes the gas was needed to make the portfolio reliable, we are hesitant to force in specific technologies into the portfolios." The IE goes on to note that when the ELCCs developed in PLEXOS in the Reliability Rubric were then fed into EnCompass to develop portfolios, EnCompass selected significantly less gas than is proposed in the Company's preferred portfolio. "[T]he portfolio did choose some gas resources totaling 400 MW, which is 200 MW less than the preferred portfolio."[21]

C. Aside From these Basic Issues of a Lack of Transparency and Preapproval, there are Serious Substantive Problems with the Company's Modeling Choices.

In addition to these serious procedural problems with the "Reliability Rubric," there are substantive problems with the various modeling inputs and methods that the Company invented in Phase II. Overall, the procedural and substantive problems with the Company's modeling make it impossible for parties and the Commission to know the optimal amount of new gas resources needed for reliability purposes. This is confirmed by the IE Report. The IE requested that the Company conduct additional EnCompass runs in which the ELCC curves developed

[18] 120-Day Report at 30.
[19] Report of the Independent Evaluator at 14 (emphasis added) [hereinafter, "IE Report"].
[20] *E.g.*, Decision No. C22-0459 at ¶ 357, 460.
[21] IE Report at 14.

from the Phase II PLEXOS modeling were used in EnCompass. The result was that EnCompass selected nearly 33% less new gas resources than in the Company's preferred portfolio: "After the 120 Day Report was filed and given the PLEXOS work that was performed on the portfolios to determine the ELCCs of the portfolio, the IE requested that those ELCCs curves be inserted back into Encompass for the least cost plan to see what was selected. As expected, the portfolio did choose some gas resources totaling 400 MW, which is 200 MW less than the preferred portfolio."[22]

The Company misleadingly claims that its "Reliability Rubric" is "unbiased" because it made the same manual adjustments to all portfolios.[23] But the problem with the "Reliability Rubric" is that it manually forced the selection of particular resource types in specific amounts, rather than allowing the model to optimize the resource type and amount. For example, the "Reliability Rubric" involved the Company to manually forcing every portfolio to include a minimum of 400 MW of new gas (except in the "No Gas" or "No New Gas" portfolios).

The Company's primary justification for manually forcing the selection of 400 MW of new gas in every portfolio is that new CTs and batteries have a similar cost (on a $/kW-month basis), but batteries have an ELCC of around 20%; therefore, the Company concludes that batteries would be approximately 5 times more expensive to meet a given capacity need.[24] There are two flaws in the Company's argument. First, energy storage provides additional grid benefits that CTs do not offer and thus a simple MW-for-MW cost comparison is insufficient. To properly compare the two technologies, a net-cost comparison including both costs and grid benefits on a MW-for-MW basis would be more appropriate. Second, the Company assumes that the CTs would have a 100% ELCC, which as explained below is not accurate. Indeed, the Company's own modeling results demonstrate how the Company erred by oversimplifying the issue. The Lower Dispatchable plan has more than 100 MW less gas CT capacity than the Preferred Portfolio, but a virtually identical PVRR. This contradicts the Company's justification for the "Reliability Rubric," which is that it is always cheaper to meet capacity needs through more gas CTs.

Furthermore, we are troubled by the Company's manual adjustments because they assume that the only way to design a portfolio to meet extreme weather events is to force a portfolio to add either more gas CTs or more 2- or 4-hour batteries. In reality, utilities have many more options at their disposal to address extreme weather: adding transmission, including interregional transmission, to access resources that may not be affected by the weather event in question; adding demand response; adding longer-duration storage; modifying existing thermal units that lack dual-fuel capability and/or are not winterized. In the real world, these are some of the many steps that utilities and ISOs/RTOs are taking to address extreme weather. The Company's "Reliability Rubric" ignores these real-world solutions in favor of a binary choice between new gas CTs or new 2- or 4-hour batteries, which is bad resource planning and will lead to less reliable portfolios and higher costs for customers.

In addition, we remain troubled by the Company's assumptions regarding the availability of thermal generation during extreme weather events compared to renewables. The 120-Day Report states that in the extreme weather sensitivities, the Company assumed reduced solar and wind output, but does not provide the Company's assumptions regarding thermal units' availability during extreme weather events. It is of course true that extreme weather events can

[22] IE Report at 14.
[23] 120-Day Report at 30, 30 n.16, 73.
[24] *Id.* at 80.

impact renewable output, and modeling should account for this risk. But it is equally true that extreme weather poses risks to thermal generators. Several ISOs and RTOs have published reports documenting the high outage rates of coal and gas units during recent extreme weather events, particularly winter events.[25] In addition, this Commission is well aware from Winter Storm Uri that even if gas generators remain online during a winter storm, the cost to procure gas can skyrocket. The 120-Day Report does not offer information on the assumed availability of coal and gas resources, and their assumed costs, in the extreme weather event sensitivities. Without this information, it is impossible for us to meaningfully evaluate the merits of the extreme weather sensitivities, which significantly affected the composition of the portfolios in the 120-Day Report.

To be very clear, we support modeling extreme weather events, and we support doing round-trip modeling to check that portfolios produced through capacity expansion modeling are reliable. We are not objecting to the modeling of extreme weather per se, nor are we objecting to round-trip modeling per se. Instead, we object to the Company inventing modeling assumptions in Phase II that were never approved in Phase I, we object to the specific assumptions and methods the Company adopted in Phase II, and we object to the Company not providing "before and after" information in the 120-Day Report with the composition and costs of all base EnCompass portfolios and the specific portfolio adjustments and cost changes made to all base EnCompass portfolios.

III. PORTFOLIO AND BID SELECTION

Given the serious problems with the Company's modeling that are described above, if this case had not already been delayed both in Phase I and II, we would strongly recommend that the Commission not approve any resources until the Company to reruns its modeling and the parties can litigate the new modeling methods the Company adopted in Phase II. But it is imperative that the renewable and battery storage projects move forward as quickly as possible, in order to take advantage of these cost-effective bids and develop resources needed to meet emission-reduction targets. Accordingly, we do not wish to delay approval of renewable and battery storage bids and associated transmission projects.

However, the proposed gas resources are different, because the Company's manual adjustments had the largest impact on the selection of gas resources. All 628 MW of new gas in the Company's Preferred Portfolio were manually forced into the portfolio—they were not selected by the model as the economically optimal resources. More broadly, the "Reliability Rubric" forced at least 400 MW of new gas in <u>every</u> portfolio other than the No New Gas and No Gas portfolios. To approve the new gas resources in the Company's Preferred Plan, the Commission would have to turn a blind eye to these egregious deviations from how modeling in a resource plan is supposed to be done, and the Commission would have to ignore these serious violations of the Updated Settlement Agreement and the Commission's merits Order in Phase I.

In the subsections below, we address the following issues:

- whether the Commission should approve any new gas resources now, or defer consideration of new gas resources;

[25] *E.g.*, FERC, NERC, "The February 2021 Cold Weather Outages in Texas and the South Central United States" (2021); FERC, NERC, "Elliott Report: Complete Electricity Standards, Implement Gas Reliability Rules" (2023; SPP, Southwest Power Pool's Response to the December 2022 Winter Storm (2023); Astrape, "SPP Correlated Outages Analysis," prepared for SPP (2022).

- which portfolio the Commission should use as the basis for approving bids for non-gas resources and/or for gas resources;
- whether to approve the proposed Hayden biomass project; and
- whether to approve the gas back-up bid intended to meet potential new demand.

A. The Commission Should Defer Approval of Any New Gas.

First, at a minimum, the Commission should state clearly in its Phase II order that the Commission expects that all modeling inputs and methods used in future Phase II proceedings must have been approved by the Commission in its Phase I Order (or in a subsequent order prior to issuance of the 120-Day Report). The Commission should send a clear signal to the Company that what it did in its Phase II modeling here will not be tolerated in future resource plans. This is particularly important because the Company will file a new resource plan by June 1, 2024.

Second, the Commission should decline to approve any new gas resources in this case and defer consideration of all new gas resources. [redacted]

[redacted] The Company forced the model to select one of the three bids for a new gas plant in the San Luis Valley for alleged "local reliability" reasons[26] (which the Company did not propose in Phase I, and which the Commission did not approve in Phase I), and the model selected the 28 MW gas CT. [redacted] The parties to the Updated Settlement in Phase I never agreed to these manual adjustments and the Commission did not authorize these manual adjustments in its Phase I Order.

As mentioned above, when the IE requested the Company to conduct additional EnCompass runs using updated ELCC values, EnCompass selected only 400 MW of new gas[27] —far less than the 628 MW of new gas in the Company's Preferred Plan, and less than the 504 MW of new gas in the Lower Dispatchable Plan. This calls into question whether any of the portfolios presented in the 120-Day Report contain the optimal amount of new gas.

The Company will likely respond that new gas resources must be approved now to ensure reliability, and will likely claim that there is insufficient time to defer consideration of new gas, given when new resources must be online. The Company will likely argue that if the Commission does not approve new gas units in this proceeding, any plan the Commission approves will not meet the statutory requirement that a Clean Energy Plan be reliable. It is true that the Clean Energy Plan statute, SB 19-236, provides that the Commission shall not approve a Clean Energy Plan unless it is reliable.

However, the Company's claims about reliability are based on modeling methods that were not even presented to the Commission in Phase I, let alone approved by the Commission in Phase I. Specifically, the Commission's claims about the need for new gas units rest on two unapproved reliability tests: (1) judging a portfolio as unreliable if the Company deemed it to have "failed" extreme weather sensitivities based on some unknown metrics; and (2) judging a portfolio as unreliable if it is deemed to "fail" some unspecified "portfolio ELCC" test that the Company invented in Phase II. There is no place in the Company's testimony in Phase I in which the Company proposed to use either of these methods in Phase II. While the Updated Settlement contemplated the use of extreme weather events as sensitivities, neither the Settlement nor the Phase I Order specified a metric for determining when a portfolio would be deemed to "pass" such a sensitivity or whether or how to revise a portfolio if it failed the sensitivity. Similarly, as noted above, the Company adamantly opposed the kind of "round-trip" modeling it did here in Phase II, and thus never proposed using a portfolio ELCC test in PLEXOS for assessing the reliability of portfolios. The Commission should not approve new gas units in this proceeding based on modeling methods that were not litigated and approved in Phase I.

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[26] 120-Day Report at 39 ("The Company believes it is essential from a reliability perspective to continue to have firm dispatchable generation in the region. To ensure this result, the Company added a modeling parameter to require at least one of the three submitted bids for firm dispatchable generation in the Alamosa area to be selected in the Preferred Plan."); *see also id.*

[27] IE Report at 14.

The Company may also point to the statements in the IE Report indicating that the IE believed that some amount of new gas is needed for reliability. But the IE Report casts serious doubt on whether the Company has proposed a portfolio in the 120-Day Report with the optimal amount of gas. When the IE asked the Company to re-run EnCompass, the model selected only 400 MW of gas—roughly 33% less new gas than the 628 MW of new gas in the Company's Preferred Plan. There is a critical difference between finding that some amount of new gas is needed versus approving the specific amount of new gas the Company has requested. At bottom, given the flaws in the Company's modeling, the 120-Day Report does not provide the Commission with the information needed to determine the optimal amount of new gas. The only way to determine the amount of new gas that is optimal from a cost and reliability perspective is for the Company to fix the modeling problems listed above and re-run its modeling.

For these reasons, the Commission should not approve any new gas now, and should defer consideration of new gas resources according to one of the following options. First, the Commission could approve non-gas resources from a portfolio now (such as the Lower Dispatchable Plan), order further proceedings to enable the parties to litigate the Company's new modeling assumptions and methods, and then consider approval of new gas resources several months from now. Alternatively, the Commission could instruct the Company to address the modeling issues discussed above in the June 2024 resource plan it files, and consider the new gas resources from this plan as part of the application that will be filed by June 1, 2024.

B. The Lower Dispatchable Plan Has the Same Cost As, but Lower Emissions Than, the Company's Preferred Portfolio.

Regardless of whether the Commission approves non-gas resources now and defers consideration of gas resources, or whether the Commission instead approves all resource types now, the Commission must use one of the portfolios as the basis for approving bids. We recommend that the Commission reject the Company's Preferred Plan and instead use the Lower Dispatchable Plan (minus the Hayden biomass project) as the basis for approving bids. However, we do this very reluctantly, because all of the portfolios presented in the 120-Day Report are the product of faulty modeling. The evidence suggests that even the 504 MW of new gas in the Lower Dispatchable Plan is too much, given that when the Company conducted the modeling requested by the IE, EnCompass selected only 400 MW of new gas.[28]

With those caveats, the Lower Dispatchable Plan is superior to the Company's Preferred Plan because it has the same cost but lower emissions. The PVRR of the two plans differs by a mere $1 million out of a total that exceeds $44 billion, and thus the cost should be considered the same.[29] When the social cost of emissions is included, the Lower Dispatchable Plan is more than $100 million cheaper than the Company's Preferred Plan (the PVSC of the Preferred Plan is $50,535 million, compared to $50,421 million for the Lower Dispatchable Plan).[30]

The Company states that "[it]t is important to note that just because new gas turbines are constructed, that does not lead to increased carbon emissions."[31] But the 120-Day Report shows that portfolios with lower amounts of gas CTs have higher amounts of renewables and therefore

[28] *Id.*
[29] 120-Day Report at 111 (Table 27) (showing that the PVRR of the Company's Preferred Plan is $44,191 million, and the PVRR of the Lower Dispatchable Plan is $44,192 million).
[30] *Id.*
[31] *Id.* at 80.

lower emissions. In particular, the Lower Dispatchable Plan has 124 MW less new gas and 400 MW more solar than the Company's Preferred Plan, which results in lower emissions. Through 2030, the Lower Dispatchable Plan would deliver more than 500,000 tons of additional CO_2 reductions, which grows to more than 2 million tons of additional CO_2 reductions through 2055 compared to the Company's Preferred Plan.[32]

In addition, the Lower Dispatchable Plan exceeds the required Planning Reserve Margin of 18%, with an expected PRM of 18.5% in 2028.[33] The Plan exhibits no reliability issues even under the extreme summer event (a scenario more extreme than the hot summer event).[34] The Plan has a relatively high best value employment metrics ("BVEM") score from the Labor Economist evaluation than other portfolios, indicating it creates higher quality jobs.[35] The Lower Dispatchable Plan scores 56%, while the Preferred Portfolio 57%. The Lower Dispatchable Plan also addresses the Company's local reliability concerns in the San Luis Valley, and the Company's concerns around transmission support and the existing import capability limitations into the Denver metro area load center.

C. The Commission Should Reject the Company's Request to Approve A New Gas Backup Bid for Purposes of Meeting Potential New Load.

The Company requests Commission approval for 4 backup bids, to be used to serve new load that Xcel says may materialize.[36] One of the bids is a 219 MW gas plant (Bid 0235) that would enter service in 2027. As explained previously, the Company adopted a number of new input assumptions and modeling methods that were never vetted and approved in Phase I, and that either forced the selection of new gas or affected the selection of new gas in portfolios. This calls into question the appropriateness of the new gas in the portfolios. At a minimum, that should lead the Commission to reject the new gas backup bid that the Company requests authorization to use to meet potential new load. Instead, the issue of whether any new gas resources are needed to meet prospective new load should be addressed in the June 2024 resource plan proceeding.

D. The Commission Should Reject the Extremely Expensive Hayden Biomass Project.

We recommend that the Commission reject the Hayden Biomass Project, for several reasons. First and foremost, the project is extremely expensive. The Hayden Biomass Project would provide 19 MW of accredited capacity and 26 long-term jobs but increase the PVRR by $280 million relative to portfolios that do not include the Hayden Biomass Project.

The Company presented its Preferred Portfolio without the Hayden Biomass Project in the Inverse 1324 Plan. The tables below show that the Inverse 1324 Plan is cheaper than the Company's Preferred Plan under the base case and all sensitivities.[37] The tables also show that

[32] 120-Day Report at 111 (Table 27).
[33] *Id.*
[34] *Id.* at 78 (Table 19).
[35] *Id.* at 51 (Figure 11).
[36] *E.g.*, 120-Day Report at 55.
[37] The tables contain data from the 120-Day Report, Appendix W - Annual Nominal Cash Flows (executable).

the plan that omits the Hayden biomass project is cheaper both with and without the social cost of emissions included in the calculations.[38]

Scenario	SCC Portfolio	NPV 2023 - 2050 ($mil)		Lowest-cost rank (=1) within scenario	
		PVRR	PVSC	PVRR	PVSC
Reference	1 - Preferred Plan (SCC)	$42,087	$48,432	11	10
	2 - Inverse 1324 Plan (SCC)	$41,808	$48,132	1	4
	6 - Lower Dispatchable Plan (SCC)	$42,088	$48,317	12	9
Annuity Tail	1 - Preferred Plan (SCC)	$42,066	$48,241	3	3
	2 - Inverse 1324 Plan (SCC)	$41,728	$48,014	1	2
High Gas	1 - Preferred Plan (SCC)	$42,421	$48,790	4	4
	2 - Inverse 1324 Plan (SCC)	$42,136	$48,485	1	2
	6 - Lower Dispatchable Plan (SCC)	$42,391	$48,648	3	3
Low Gas	1 - Preferred Plan (SCC)	$41,805	$48,102	3	4
	2 - Inverse 1324 Plan (SCC)	$41,529	$47,806	1	2
	6 - Lower Dispatchable Plan (SCC)	$41,829	$48,005	4	3

Scenario	$CO2 Portfolio	NPV 2023 - 2050 ($mil)		Lowest-cost rank (=1) within scenario	
		PVRR	PVSC	PVRR	PVSC
Reference	1 - Preferred Plan ($0CO2)	$42,344	$49,308	10	9
	2 - Inverse 1324 Plan ($0CO2)	$42,041	$48,903	4	3
	6 - Lower Dispatchable Plan ($0CO2)	$43,212	$49,676	12	10
Annuity Tail	1 - Preferred Plan ($0CO2)	$42,142	$49,061	3	3
	2 - Inverse 1324 Plan ($0CO2)	$41,858	$48,778	2	2
High Gas	1 - Preferred Plan ($0CO2)	$42,810	$49,801	4	4
	2 - Inverse 1324 Plan ($0CO2)	$42,477	$49,365	3	3
	6 - Lower Dispatchable Plan ($0CO2)	$43,555	$50,048	6	5
Low Gas	1 - Preferred Plan ($0CO2)	$41,952	$48,878	4	4
	2 - Inverse 1324 Plan ($0CO2)	$41,673	$48,497	3	3
	6 - Lower Dispatchable Plan ($0CO2)	$42,917	$49,343	6	5

Second, we have concerns about the Company's claims that the Hayden Biomass Project should be deemed to deliver net emission reductions. The Company has not committed to the sources of the biomass to be used in the Project and has not provided any evidence about what would become of that biomass absent its use in the Hayden Biomass Project. Given this lack of information, we have serious concerns about the accuracy of the Company's claims regarding the alleged emission benefits of the Hayden Biomass Project.

The Commission can reject the Hayden Biomass Project and still consider additional measures for the Hayden community. The last unit at Hayden is not scheduled to retire until

[38] *Id.*

2028. The Company will be filing its Just Transition solicitation no later than June 1, 2024, to procure resources to come online in 2029 and afterwards. Thus, to the extent the Commission wishes to consider additional measures for the Hayden community, that can be done in the resource plan proceeding the Company files next year.

For all these reasons, the Commission should not approve the Hayden Biomass Project and should instead approve Bid 0474, the 200 MW solar project that was selected in lieu of the Hayden Biomass Project.

IV. CONDITIONS FOR ANY NEW GAS APPROVED IN THIS PLAN

Given that all of the proposed new gas was forced into portfolios by the Company based on modeling methods that the Commission never approved, the Commission should defer consideration of new gas resources. But if the Commission disagrees, we suggest that the Commission impose guardrails on any new gas resources.

The Company has a goal of delivering electricity with net-zero-emissions by 2050.[39] This aligns with 2023 Colorado legislation to "eliminate statewide greenhouse gas pollution by the middle of the twenty-first century" by setting a goal of a "one hundred percent reduction in statewide greenhouse gas pollution by 2050."[40] Given the Company's and the State's goal of being net-zero-emissions by 2050, the Company's proposals to bring new gas plants online in 2027 would impose two significant cost risks on customers.

First, the Company modeled all portfolios in the 120-Day Report as achieving zero carbon emissions in 2050. In modeling new gas plants, the Company has assumed that all new gas plants procured here will eventually be able to burn 100% hydrogen[41] and that starting in 2050 they do in fact burn 100% hydrogen. The Company is proposing to make a massive bet with ratepayer money: a bet that sufficient quantities of zero-emission hydrogen will become available, at a reasonable cost, to be burned in the new gas plants it builds; and that these new gas plants can be modified to burn 100% hydrogen. At present, none of the infrastructure exists in Colorado to produce and transport hydrogen to power plants in sufficient quantities, and it is unclear whether and to what extent turbines capable of burning 100% hydrogen are commercially available today (the Company indicates that most of the bids it received for new gas units would not be capable of burning 100% hydrogen without modifications).[42] Additionally, without a commitment from the Company to only use zero-emission hydrogen that accounts for emissions from hydrogen production, emissions could increase overall, as the production of hydrogen is highly energy-intensive and most hydrogen available today is made from fossil fuels.

Even if the Company's bet on the technical feasibility of converting new gas plants to burn 100% hydrogen were to pan out, the Company has not included in the modeling all of the costs that would be needed for these new gas plants to be capable of burning 100% hydrogen. In modeling new gas plants as burning hydrogen, the Company assumed a hydrogen fuel cost that we understand to include the cost to procure the hydrogen, inclusive of any transportation costs. However, the Company indicates that with the potential exception of one bid, all of the bids for

[39] https://co.my.xcelenergy.com/s/our-commitment/carbon-reduction-plan

[40] Senate Bill SB 23-016, Section 8, codified at § 25-7-102(2)(g)(I), (2)(g)(I)(F), C.R.S.

[41] 120-Day Report at 124-25.

[42] *See id*.

new gas units would not initially be able to burn 100% hydrogen.[43] That means that any new gas plants procured as part of this Phase II ERP would have to be modified to be able to burn 100% hydrogen. We have seen no evidence that the Company included costs associated with these modifications in modeling new gas units. As GE explains, it would be necessary to make major modifications to multiple components of a gas plant to enable it to burn 100% hydrogen: "In addition to differences in the combustion properties of hydrogen and natural gas, it's also important to consider the impact to all gas turbine systems, as well as the overall balance of plant. In a power plant with one or more hydrogen-fueled turbines, changes may be needed to the fuel accessories, bottoming cycle components, and plant safety systems."[44]

Moreover, the Company is attempting to have all of its gas plants have on-site fuel storage, such that all gas plants have several days' worth of fuel available for extreme weather events. Given the very small molecular size of hydrogen, it cannot be stored safely in the same containers that oil or gas is stored in, and thus new on-site storage would need to be constructed to store hydrogen. This, too, is a cost that has not been included in the modeling for new gas units.

As a result, if the Company were to build new gas plants and then later modify them to burn 100% hydrogen, customers would incur higher costs than the Company has assumed here. The Commission should not allow the Company to underestimate the costs of new gas plants and force ratepayers to pay the future hydrogen conversion costs that the Company has ignored in its modeling. Therefore, the Commission should instead place the risk on the Company: for any new gas plants approved in this Phase II ERP, if the Company incurs costs to make the plants zero-emission that are higher than what the Company has estimated here, the Company should bear 100% of those costs.

Second, in the Updated Settlement Agreement in Phase I, the Company agreed to treat new gas units as having a 25-year depreciable life for modeling purposes only.[45] The Updated Settlement states that "[f]or any new natural gas assets included in a final approved resource plan, the Company will address the depreciable life for such assets for ratemaking purposes through an appropriate future depreciation study."[46] Given that the Company has not committed to depreciating new gas plants by 2050, we assume that the Company intends to depreciate new gas plants beyond 2050. Even if the Company were intending to depreciate new gas units over 25 years, given that the new gas resources proposed here are modeled as entering service in 2027, using 25-year lives assumes the new gas plants would be depreciated past 2050, when the Company assumes its system is zero-carbon. This puts the risk on ratepayers that these new gas plants will become stranded assets prior to the end of their depreciable lives. To mitigate the risk of new gas units becoming stranded assets, the Commission should order that cost recovery for any new gas plants should be based on depreciating the plants by 2050 (if not sooner).

[43] *See id.*
[44] GE, "Hydrogen field gas turbines," *available at* https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines?utm_campaign=h2&utm_medium=cpc&utm_source=google&utm_content=rsa&utm_term=Hydrogen%20gas%20turbine&gad_source=1&gclid=Cj0KCQjwtJKqBhCaARIsAN_yS_lzarMAYGvTJ1nCZNx0sfU4wREuK7EnsJoK-o4ri7hEfxSkrQP-mrEaAub2EALw_wcB.
[45] H'rg. Exh.156 (Updated Non-Unanimous Partial Settlement Agreement) at ¶ 24.
[46] *Id.*

V. RECOMMENDATIONS FOR PSCO'S NEXT RESOURCE PLAN FILING IN JUNE 2024

Pursuant to the Commission's Phase I Order approving the Updated Settlement Agreement, the Company is required to file a Phase I resource application no later than June 1, 2024–what it calls the "Just Transition Solicitation."[47] The Company's 2024 resource plan proceeding is supposed to be an expedited proceeding relative to a typical ERP. As a result, it is important for the Commission to provide guidance now to the Company on modeling issues that are disputed here, to try to prevent these disputes from recurring in the resource planning proceeding that begins next year.

A. The Commission Should Instruct the Company to Provide All Relevant Data to Intervenors.

In this Phase II proceeding, the Company did not provide the parties with the input and output files for the EnCompass and PLEXOS modeling it conducted in Phase II.[48] The Company also did not provide meaningful explanations of several of the assumptions and metrics that the Company adopted in Phase II for the first time. Precisely because the modeling methods the Company invented in Phase II had not been litigated in Phase I, we had not had the opportunity to fully vet these new methods in Phase I, and Phase II does not provide the opportunities for discovery, testimony, and a hearing that are available in Phase I.

To prevent this problem from recurring, the Commission should instruct the Company that in the 2024 Just Transition Solicitation, the Company should, in both Phase I and Phase II:

- Provide intervenors with all input and output files from all modeling the Company conducts,
- Provide written explanations for all manual adjustments it makes to the modeling; and
- Provide details on the composition and costs of all portfolios before and after manual adjustments.

B. The Commission Should Instruct the Company to Improve its Reliability Analyses.

The Company's approach to reliability in its modeling could be improved in several ways. The Company continues to treat new gas as a perfect capacity resource, which is inaccurate. The Company goes to great lengths to properly accredit the capacity of wind, solar, and battery resources, but does not undertake this same process for gas resources. Instead, the Company assumes that all thermal resources are available at their installed capacity ("ICAP") rating and not even discounted to its unforced capacity ("UCAP," or installed capacity minus a forced outage rate). This approach fails to recognize the impact of correlated, weather-dependent outages of thermal generation. In reality, thermal units have been the primary cause

[47] *Id.* at ¶ 45.

[48] To be clear, we are not claiming that there is a Commission rule or order that required the Company to provide all input and output files to the parties in Phase II. We are simply observing that the Company did not provide these modeling files to the parties, which impeded our ability to review the Company's modeling, particularly because of the manual adjustments the Company made.

of reliability issues during several recent extreme weather events. In particular, gas-fired power plants that do not have dual-fuel capability or on-site gas storage have been a main contributor to reliability issues in Winter Storm Uri and Winter Storm Elliot, with gas-fired power plants going off-line due to components freezing or not being able to secure enough gas to operate. We are encouraged by requirements related to "Backup Fuel and Other Dispatchable Resource Capabilities" that require dual fuel capability for gas resources. However, even with these requirements, recent reports have found that many natural gas resources have experienced increased forced outage rates during extreme weather, especially extreme cold snaps.[49] And even when gas-fired resources have performed well during extreme weather, the price of gas can often skyrocket during winter storms, as happened to the Company during Winter Storm Uri, resulting in hundreds of millions of dollars in extra fuel costs. For these reasons, the Company should conduct a study of the capacity credit that thermal resources should receive for planning purposes.

In addition, we continue to have concerns about the ELCC for batteries. When the ELCC curves were developed, they assumed that early additions of *both* 2-hour and 4-hour battery storage resources received high capacity credit. This resulted in an economic selection of 2-hour resources first, followed by more expensive 4-hour resources later. However, knowing that future additions of 4-hour resources would be necessary to maintain reliability, it may be more economic to make any battery additions longer duration (at least 4-hours) at the outset. Increasing the duration of energy (MWh) to the battery power (MW) is less costly than adding new batteries. Going forward, we suggest running the Preferred Portfolio, swapping all 2-hour storage resources with 4-hour resources, and then determining the total gas needed to meet similar reliability requirements as the preferred portfolio. This is particularly important for the standalone resources.

With respect to round-trip modeling, we are pleased that the Company has reversed its position and now sees the value of conducting round-trip modeling (i.e., after EnCompass is used to develop a portfolio, running that portfolio through SERVM or PLEXOS to evaluate the reliability of the portfolio). However, the Company's ELCC Analysis in PLEXOS continues to have many of the same challenges and limitations as in the Phase I ERP, likely understating benefits of storage additions. These problems were identified by Mr. Stenclik in the Phase 1 ERP.[50] For example, in the Phase II reliability rubric modeling, the Company schedules the storage resources exogenously to the PLEXOS model, and schedules storage against the *average* loss of load probability rather than the specific loss of load events that occur. This potentially diminishes the value of storage and may lead to less reliable state of charge management. "An alternative method in PLEXOS would be to use stochastic ST simulations. In this example, hourly production cost simulations are conducted across a wide range of samples. Any data input

[49] *See supra* note 22.

[50] H'rg Exh. 1403, Rev. 1 (Answer Testimony of Derek Stenclik) at 37, stating that: In the ELCC Study, the Company performed calculations using the PASA module. This module is used for scheduling generator maintenance and calculating some reliability indices but cannot be used for scheduling chronological and sequential operations. Instead, the year is divided into a series of steps (i.e. hour, day, week) and availability of a resource in each step is defined. While hourly steps were modeled by the Company, these steps are treated independently of one another in a load duration curve. A resource's availability in one hour is not influenced by adjacent hours. In the case of energy storage, this requires utilization profiles to be input into the model exogenously rather than scheduled based on reliability needs. In this case, storage was scheduled against the hourly loss of load probability, however this represents the average or expected LOLP, which is spread out over many hours, rather than unserved energy in individual events that are narrower."[...]

in the model can be stochastically generated, including generator outages and wind and solar availability. In this example, the system is dispatched sequentially, and storage is scheduled taking into account its power and energy constraints. This is done separately across hundreds of samples, allowing storage schedules to be adjusted based on system needs. While this method is more complex, it is more accurate and better reflects energy storage capabilities. This is a similar methodology deployed in the SERVM modeling conducted for the PRM Study."[51] This is the methodology used in the SERVM PRM and ELCC Studies conducted by Astrape and can be developed and implemented in PLEXOS as well.

Rather than using the reliability rubric to recalculate ELCC contributions, the round-trip modeling should be used to directly assess whether the portfolios meet the 1-day-in-10-year LOLE reliability criterion. This would avoid the circular nature of the portfolio ELCC calculations altogether.

To prevent the problems listed above from recurring, the Commission should instruct the Company that in the 2024 Just Transition Solicitation, the Company should:

- Conduct capacity accreditation studies and planning reserve studies in the same software tool and database to ensure consistency (which the Independent Evaluator recommends as well),[52]
- Apply similar capacity accreditation techniques to all resources, including gas and coal plants rather than assuming installed capacity or unforced capacity for the PRM,
- Build all portfolios in both Phase I and II to the same minimum level of reliability
- Evaluate the marginal ELCC of battery storage resources at increasing levels of renewable adoption to ensure portfolio effects are captured in the initial ELCC curves,
- Conduct a reliability back-check of resulting EnCompass portfolios to ensure they meet a 1-day-in-10-year LOLE (or alternative) reliability criterion, rather than rely on PRM or ELCC adjustments, and
- Clearly identify when, and to what extent, resources are selected outside of the capacity expansion process to meet reliability needs,

C. The Commission Should Instruct the Company to Improve its Analyses Regarding Potential New Gas Resources.

If the Commission defers consideration of any new gas resources to the 2024 Just Transition Solicitation, the Commission should instruct the Company, in its Phase I filing in 2024, to provide additional information on short-term extensions to existing gas plants. The Company provided some information on this topic in the 120-Day Report.[53] However, given the limited information provided, and the absence of discovery in Phase II, there was not enough information for us to evaluate the Company's engineering and cost claims regarding short-term extensions to certain existing gas plants.

In addition, as discussed above, the Company assumed that all new gas resources would burn increasing amounts of hydrogen, culminating in burning 100% hydrogen by 2050.

[51] *Id.* at 38.
[52] IE Report at 15 (". . . the IE recommends that the PRM and ELCC calculations are performed across one model.").
[53] 120-Day Report at 117-21

However, the Company did not include estimates for all costs necessary for a gas unit that comes online in 2027 to transition to burning 100% hydrogen. To fix this problem, the Commission should instruct the Company in its June 2024 filing to:

- Include estimates for the costs of all measures needed to make new gas units zero-emissions. If the Company continues to assume that new gas units will burn increasing amounts of hydrogen, and eventually burn 100% hydrogen, the Company should include in the modeling of all new gas resources:
    - The fuel costs for demonstrably zero-emission green hydrogen;
    - The cost to construct dedicated pipelines for transporting hydrogen to the new power plants;
    - The cost to acquire and install new turbines or to modify the turbines, as well as the cost to modify all other facility equipment that would have to be modified to accommodate burning 100% hydrogen; and
    - The cost to construct storage facilities capable of safely storing several days' worth of hydrogen on-site.

D. The Values for the Social Cost of Carbon May Need to be Updated in the Next Filing.

In Phase II, the Company used a social cost of carbon ("SCC") that starts at $69.33 per ton in 2020. This is based on the Federal Interagency Working Group ("IWG") estimate from February of 2021.[54] In September 2022, the federal EPA (which is part of the IWG) released new estimates of the social costs of greenhouse gasses, which are much higher than what the Company assumes in this filing.[55] We mention this here because of the magnitude of the difference between EPA's numbers and the current IWG numbers that the Company used here. For instance, the Company assumes a social cost of carbon of $69 per short ton in 2020 but the latest comparable EPA estimate is $109 per ton in that year.[56] If the Interagency Working Group updates the social cost of carbon prior to the Company filing its June 2024 plan, the Company should use the updated IWG values for the social cost of carbon.

In addition, we continue to have concerns about discounting the social costs of carbon and methane using the same weighted average cost of capital ("WACC") to discount other costs. This concern is based on the fact that, even before the Company has done any discounting, these social costs were already developed using social discount rates. For instance, the Company has used the 2021 social cost of carbon and methane values from the Interagency Working Group, which used a 2.5% discount rate to develop the social costs.[57] The Company's practice of discounting the social costs by the WACC results in a much higher discount rate than what is

[54] 120-Day Report, Appendix D at 9.

[55] EPA, Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances (2022), *available at* https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf).

[56] The SCC values from IWG and EPA are in terms of metric tonnes while Xcel reports short tons. Thus, the values per short ton are converted using a factor of 1.10231 short tons per 1 metric tonne.

[57] 120-Day Report, Appendix D at 9. This means that the cost of emissions in 2030 is the value of future damages from emissions in that year and future years—all discounted back to 2030 at a rate of 2.5%. This is the reason that SCC values are different for each discount rate: the discounting of future costs is embedded in the dollar per ton value. (Note: This is separate from inflation adjustments—or conversion between real and nominal dollars.)

already embedded in the Interagency Working Group's calculations of the SCC and SCM.[58] The choice of the discount rate has a significant impact on the resulting values as shown below. The PVSC savings from the Lower Dispatchable or Inverse 1324 plans compared to the Preferred Plan all increase with one exception. The relative costs of the Lower Dispatchable plan are substantially reduced relative to the Company's plan.

Scenario	SCC Portfolio	PVSC relative to Pref Plan ($mil)	
		Xcel	2.5% discount
Reference	1 - Preferred Plan (SCC)	$0	$0
	2 - Inverse 1324 Plan (SCC)	-$299	-$311
	6 - Lower Dispatchable Plan (SCC)	-$114	-$179
Annuity Trail	1 - Preferred Plan (SCC)	$0	$0
	2 - Inverse 1324 Plan (SCC)	-$227	-$161
High Gas	1 - Preferred Plan (SCC)	$0	$0
	2 - Inverse 1324 Plan (SCC)	-$305	-$317
	6 - Lower Dispatchable Plan (SCC)	-$142	-$207
Low Gas	1 - Preferred Plan (SCC)	$0	$0
	2 - Inverse 1324 Plan (SCC)	-$296	-$308
	6 - Lower Dispatchable Plan (SCC)	-$97	-$163

We realize that this issue was litigated and decided by the Commission in Phase I. We are raising the issue again here not to relitigate the issue in this proceeding, but to point out that the remains a contested issue that will likely resurface in the next resource plan. For that reason, the Commission should consider requesting the Company to confer with stakeholders to reach a consensus approach to discounting the social cost of emissions for the June 2024 filing.

VI. RECOMMENDATIONS TO REDUCE THE BURDEN TO PARTIES AND THE COMMISSION FROM THE NUMBER OF CPCN APPLICATIONS

Regardless of which bids the Commission ultimately approves in this case, the large size of the resource need and amount of bids in each portfolio means that the Company will be filing an unprecedented number of CPCN applications after this Phase II decision. For example, assume hypothetically that the Commission were to approve the Company's Preferred Plan (which we do not recommend and do not support). The Company would then need to file CPCN applications for 5 wind projects, 4 solar and solar+storage projects, and 3 gas projects, for a total of 12 separate CPCN applications (plus a CPCN for the proposed biomass project).

We do not think it is tenable or desirable for the parties to litigate a dozen, separate CPCN proceedings as a result of this single Phase II decision. Accordingly, the Commission should consider how it can reduce the litigation burden to parties (and the burden on the Commission). Specifically, we recommend that the Commission do one of the following:

[58] Going back to the 2030 emissions example: the 2030 dollars per ton has an embedded 2.5 discount rate, then the Company discounts those 2030 dollars back to 2023 using its 6.42 percent rate, as it does with other costs.

- Instruct the Company to confer with all of the parties to this case; file a report containing either a consensus proposal for how to consolidate and minimize the number of CPCN applications or the parties' various proposals if no consensus is reached; and then the Commission would issue an Order in this docket regarding how to consolidate the CPCN proceedings.

  <u>or</u>

- Order that the Commission will reduce the total number of CPCN proceedings by consolidating the Company's CPCN applications according to some criterion or criteria, such as expected online date, or by technology type (e.g., there would be a single proceeding for all of the Company's CPCN applications for wind resources, a separate proceeding for all of the Company's CPCN applications for solar resources, etc.).

CONCLUSION

NRDC and Sierra Club appreciate the opportunity to submit these comments on the Company's Phase II ERP.

Dated November 8, 2023.

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CERTIFICATE OF SERVICE

I certify that on November 8, 2023, a true and correct copy of the foregoing **Comments of Natural Resources Defense Council and Sierra Club ("Conservation Coalition") on the 120-Day Report** in Proceeding No. 21A-0141E was e-filed with the Colorado Public Utilities Commission and served on the parties via electronic mail.

Dated November 8, 2023.

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