Decision No. C23-0193

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 22A-0230E

IN THE MATTER OF THE APPLICATION OF BLACK HILLS COLORADO ELECTRIC, LLC FOR (1) APPROVAL OF ITS 2022 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN, AND (2) APPROVAL OF ITS 2023-2026 RENEWABLE ENERGY STANDARD COMPLIANCE PLAN.

COMMISSION DECISION ADDRESSING THE 2022 PHASE I ELECTRIC RESOURCE PLAN, CLEAN ENERGY PLAN, AND 2023-2026 RENEWABLE ENERGY STANDARD COMPLIANCE PLAN, AND APPROVING IN PART, AND WITH MODIFICATIONS, THE UNANIMOUS COMPREHENSIVE SETTLEMENT AGREEMENT

Mailed Date: March 22, 2023
Adopted Date: March 8, 2023

I. BY THE COMMISSION

A. Statement

1. This Decision approves, with modifications, the 2022 Electric Resource Plan (ERP) and the 2023-2026 Renewable Energy Standard (RES) Compliance Plan that Black Hills Colorado Electric, LLC (Black Hills or the Company) filed on May 27, 2022.

2. Black Hills' ERP includes a Clean Energy Plan (CEP) to reduce the Company's carbon dioxide (CO2) emissions by a target of 80 percent by 2030 as compared to 2005 levels.[1] In furtherance of Colorado's energy policy, we authorize Black Hills to further implement the statutory requirements for approval of its CEP. In Phase II of this Proceeding, we will conclude our evaluation of, *inter alia*, the actions and investments projected to achieve compliance with the clean energy targets in § 40-2-125.5(3)(a)(I) and (3)(a)(II), C.R.S. and determine whether the CEP is in the public interest and consistent with the clean energy target in § 40-2-125.5(3)(a)(I), C.R.S.

[1] Black Hills and the intervenors submit that Black Hills voluntarily elected to make itself subject to § 40-2-125.5, C.R.S., and with it the requirement that Black Hills reduce its greenhouse gas emissions by at least 80 percent from 2005 levels by 2030. (Settlement Agreement, ¶ 1).

Accordingly, we authorize Black Hills to implement a competitive bidding process for acquiring cost-effective resources to meet its projected resource need from 2022 through 2030. We also approve the process for evaluating bids to the competitive solicitation and establish the modeling parameters, including inputs and assumptions, for the presentation and consideration of potential resource portfolios in compliance with this Decision.

3. Black Hills' 2023-2026 RES Compliance Plan sets forth the actions the Company intends to take to comply with additional statutory and regulatory requirements, detailing the Company's projected Renewable Energy Standard Adjustment (RESA) retail rate impacts and projected costs, and updating the Company's proposed offerings, capacity levels, and incentives for on-site solar programs, community solar gardens (CSGs), and a new offsite solar program.

4. Consistent with the discussion below, the ERP and 2023-2026 RES Plan are approved, with modifications, in accordance with the Unanimous Comprehensive Settlement Agreement that Black Hills filed on January 13, 2023.

B. Discussion

1. Electric Resource Planning

5. The Commission's ERP Rules, set forth at 4 *Code of Colorado Regulations* (CCR) 723-3-3600, *et seq*., serve two primary functions. First, the rules require a regular, periodic examination of an electric utility's energy sales and demand forecasts as compared to an assessment of its existing resources to ensure that sufficient generation will be available to meet customer needs in the future. Second, the Commission's review and approval of an ERP ensures that the utility acquires a cost-effective mix of additional resources consistent with the state's public policy objectives, such as the RES at § 40-2-124, C.R.S.

6. As established in the ERP Rules, for decades Colorado electric utilities have used competitive bidding to procure additional resources to meet identified future resource needs. An ERP thus describes in detail how the utility will evaluate the bids and proposals submitted in response to Requests for Proposals (RFP), including the inputs and assumptions to its bid evaluation models (*e.g.*, natural gas prices, coal prices, carbon costs, discount rates, and integration costs for intermittent resources), and how it will apply resource selection criteria.

7. The ERP process includes two phases. In Phase I, the Commission reviews and may approve, or approve with modifications, the utility's plan to acquire new utility resources.[2] In Phase II, the Commission determines whether the utility should be granted a presumption of prudence for pursuing the acquisition of particular resources.

8. Phase II begins after the Commission issues its Phase I decision. Black Hills will issue its RFP, receive competitive bids and utility-owned proposals, and file a report in this Proceeding no later than 120 days after the bids are received in accordance with Rule 4 CCR 723-3-3613(d) (the 120-Day Report). The 120-Day Report will present an evaluation of all proposed resources, based on the criteria established in the Phase I decision. At the end of Phase II, the Commission issues a final decision that will approve, condition, modify, or reject the utility's preferred cost-effective resource plan.[3]

9. Black Hills shall pursue the final cost-effective resource plan in accordance with the Phase II decision, either with due diligence reviews and contract negotiations, or with

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[2] *See* Rule 4 CCR 723-3-3617(c) ("the Commission shall specifically approve or modify: the utility's assessment of need for additional resources in the [RAP]; the utility's plans for acquiring additional resources…; components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria; and, the alternate scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources, demand-side resources, or Section 123 resources").
[3] *See* Rule 4 CCR 723-3-3613(h).

applications for Certificates of Public Convenience and Necessity (CPCNs), as necessary, in accordance with Rule 4 CCR 723-3-3613(h).

2. Clean Energy Plans Pursuant to SB 19-236

10. While the above rules and competitive bidding processes are foundational to the Commission's utility resource planning process, recent legislative changes, including Senate Bill (SB) 19-236, further overlay CEP considerations on Black Hills' current ERP.

11. SB 19-236 enacts § 40-2-125.5(1)(e), C.R.S., that declares the statewide importance of promoting cost-effective clean energy and new technologies and reduction of carbon dioxide emissions from the Colorado electric generating system and includes that "[a] bold clean energy policy will support this progress and allow Coloradans to enjoy the benefits of reliable clean energy at an affordable cost." Specifically, § 40-2-125.5(3)(a), C.R.S., requires that, in addition to the other requirements of the section, a qualifying retail utility shall meet the following clean energy targets:

> (I) By 2030, the qualifying retail utility shall reduce the carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by eighty percent from 2005 levels [; and]
>
> (II) For the years 2050 and thereafter, or sooner if practicable, the qualifying retail utility shall seek to achieve the goal of providing its customers with energy generated from one-hundred-percent clean energy resources so long as doing so is technically and economically feasible, in the public interest, and consistent with the requirements of this section.

12. Under § 40-2-125.5(2)(I)(c), C.R.S., a qualifying retail utility for the purposes of SB 19-236 means a retail utility providing service to more than 500,000 customers or any other electric utility that opts in pursuant to subsection § 40-2-125.5(3)(b). Section 40-2-125.5(3)(b) simply states that any utility may opt into the full terms of § 40-2-125.5 upon notification to the Commission.

13. The statute further dictates in subsection (4) what a CEP must include (*e.g.*, a plan of actions and investments projected to achieve compliance with the clean energy targets set forth in subsections (3)(a)(I) and (3)(a)(II), the projected costs of the CEP's implementation, and workforce transition and community assistance plans).

14. Subsection 4(d) includes that the Commission "shall approve the [CEP] if the commission finds it to be in the public interest and consistent with the [80 percent target], and the commission may modify the plan if the modification is necessary to ensure the plan is in the public interest." In evaluating whether a CEP submitted is in the public interest, the Commission is directed to consider the following factors, "among other relevant factors as defined by the commission":

> (I) Reductions in carbon dioxide and other emissions that will be achieved through the clean energy plan and the environmental and health benefits of those reductions;
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> (II) The feasibility of the [CEP's] impact on the reliability and resilience of the electric system. The commission shall not approve a plan that does not protect system reliability.
>
> (III) Whether the [CEP] will result in a reasonable cost to customers, as evaluated on a net present value basis.[4]

15. If the Commission approves a CEP that achieves an emission reduction of at least 75 percent from 2005 levels, then the relevant utility is provided with a "safe harbor" from any additional emission reduction regulations that the Air Quality Control Commission (AQCC) might develop for the power sector through 2030.[5]

16. As a general matter, Colorado Department of Public Health and Environment (CDPHE) is tasked with calculating whether a proposed CEP will meet these clean energy targets.

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[4] § 40-2-125.5(4)(d), C.R.S.
[5] § 25-7-105(1)(e)(VIII), C.R.S.

In particular, the division of administration in the CDPHE must describe the methods of measuring CO2 emissions and verify the projected CO2 emission reductions of the CEP.[6] The statute goes on to state that the division of administration, in consultation with the AQCC, must determine whether the CEP will meet the 2030 clean energy targets, and will report to the Commission the division's calculation of CO2 emission reductions attributable to any approved CEP.[7]

17. SB 19-236 also sets forth accounting requirements to track the costs of the CEP. For instance, § 40-2-125.5(4)(a)(III), C.R.S., states the utility must "clearly distinguish" between the set of resources necessary to meet customer demands in the resource acquisition period (RAP) and the additional CEP activities that may be undertaken to meet the clean energy target of 80 percent emission reduction by 2030. The statute goes on to direct the utility to collect revenues for the additional CEP activities through a CEP rider assessed on a percentage basis on all retail customer bills.[8] This CEP rider is limited to a maximum electric retail rate impact of 1.5 percent of the total annual electric bill for each customer for implementation of the approved additional CEP activities and "may be established as early as the year following approval of a clean energy plan by the commission."[9]

18. While the statute requires the utility to use a competitive bidding process to procure any energy resources to fill the cumulative resource need derived from the ERP and CEP, the Commission must also allow the utility to own a target of 50 percent of the energy and capacity developed or acquired to meet the resource need "if the commission finds the cost of utility or affiliate ownership of the generation assets comes at a reasonable cost and rate impact."[10]

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[6] § 40-2-125.5(4)(b), C.R.S.
[7] § 40-2-125.5(4)(c), C.R.S.
[8] § 40-2-125.5(5)(a)(II), C.R.S.
[9] *Id.*
[10] § 40-2-125.5(5)(b), C.R.S.

19. We note that several of the statutory findings required to approve a CEP cannot be made in this Phase I Decision but must wait until Phase II. For instance, the actions and investments required to fill the additional resource need for the CEP, the projected cost to implement the CEP, and the cost and rate impact of the 50 percent utility ownership target will not be known until after the 120-Day Report. While this Decision cannot reach such findings at this stage, this Decision does permit Black Hills to issue the RFP and proceed to Phase II. Moreover, this Phase I Decision establishes the framework in which bids will be evaluated and selected, sets important Phase II assumptions regarding items such as the planning reserve margin, and ensures that the 120-Day Report contains the information required to make the statutory findings necessary to approve a CEP. In short, this Phase I Decision provides the Phase II framework and authorization Black Hills needs to further implement the requirements that can lead to approval of its CEP.

20. Despite the findings that we are deferring, we do not anticipate another fully litigated hearing in Phase II. Rather, the Commission will address the necessary statutory findings in its Phase II decision after the typical Phase II process (*e.g.*, upon consideration of the 120-Day Report, the parties' comments to the 120-Day Report, and the IE Report). SB 19-236 might change the objectives of the ERP process, but it does not direct any changes to the process itself.

3. Procedural Background

21. On May 27, 2022, Black Hills filed an application for approval of its 2022 ERP and CEP and the 2023-2026 RES Compliance Plan (Application). The Application filing initiated Phase I of this ERP proceeding. The Company submitted Direct Testimony of several witnesses in support of its Application. Contemporaneously with the Application, Black Hills filed a Motion for Extraordinary Protection of Highly Confidential Information (Motion for Extraordinary

Protection), a Motion for Waivers and Variances, and a Motion for Approval of an Independent Evaluator (IE) and Partial Waiver of Commission Rule 3612(a).

22. On June 24, 2022, CDPHE submitted a Motion for Limited Participation in which it requests authorization to participate in this Proceeding as a neutral verifier.

23. In Decision No. C22-0449-I,[11] the Commission set the Application for hearing before the Commission *en banc* and established the parties in this Proceeding. Parties consist of the following: Black Hills, Staff of the Public Utilities Commission (Staff), the Office of Utility Consumer Advocate (UCA), the Colorado Energy Office, the Board of County Commissioners of Pueblo County (Pueblo County), the City of Pueblo (Pueblo City), Cañon City, Walmart Inc., Energy Outreach Colorado, Western Resource Advocates (WRA), Colorado Independent Energy Association, and Interwest Energy Alliance. The Commission also directed Black Hills to file Supplemental Direct Testimony providing additional detail on the facts and circumstances surrounding the bid for the Turkey Creek Project.

24. On August 9, 2022, Black Hills filed an Unopposed Motion to Approve Procedural Schedule and Vacate Prehearing Conference and Request for Waiver of Response Time (Unopposed Motion to Approve Procedural Schedule).

25. In Decision No. C22-0494-I,[12] the Commission granted the Motion for Limited Participation that the CDPHE filed on June 24, 2022. As such, CDPHE is participating in this Proceeding as a neutral verifier. In addition, the Commission addressed the Unopposed Motion to Approve Procedural Schedule filed on August 9, 2022. Specifically, the Commission established a procedural schedule for Phase I of the Proceeding, referred certain items to an Administrative

[11] Issued August 1, 2022.
[12] Issued August 18, 2022.

Law Judge, and set a five-day evidentiary hearing from January 30, 2023, through February 3, 2023. The Commission also extended the decision deadline under § 40-6-109.5(1), C.R.S.

26. In Decision No. C22-0500-I,[13] the Commission granted the Motion for Extraordinary Protection that Black Hills filed on May 27, 2022.

27. In Decision No. C22-0558-I,[14] the Commission granted, in part, and deferred, in part, the Motion for Waivers and Variances that Black Hills filed on May 27, 2022. Specifically, the Commission granted the Company's requested waivers of Rule 3658(f)(II), Rule 3658(f)(VIII), and Rules 3652(ff), 3664(a), and 3878(b) of the Commission's Rules Regulating Electric Utilities, 4 CCR 723-3 and deferred ruling on the remaining requested waivers. Similarly, the Commission granted, in part, and deferred, in part, the Motion for Approval of an IE and Partial Wavier of Rule 3612(a) that Black Hills filed on May 27, 2022, and directed Black Hills to file a scope of work contract per Rule 3612(b) by January 16, 2023.

28. Prior to the evidentiary hearing in this Proceeding, the Commission held two public comment hearings. The first public comment hearing was in-person in Pueblo, Colorado, and the second was remote.[15]

29. On January 13, 2023, Black Hills filed an Unopposed Motion to Approve a Unanimous Comprehensive Settlement Agreement and Amend Procedural Schedule, and Request for Waiver of Response Time (Unopposed Motion to Approve the Settlement Agreement), which

[13] Issued August 24, 2022.
[14] Issued September 21, 2022.
[15] *See* Decision No. C22-0612-I, issued October 11, 2022.

included the Unanimous Comprehensive Settlement Agreement (Settlement Agreement). A copy of the Settlement Agreement is attached to this Decision as Attachment A.

30. In Decision No. C23-0058-I,[16] the Commission granted, in part, and deferred, in part, the Unopposed Motion to Approve the Settlement Agreement. Specifically, the Commission granted the request to vacate certain procedural deadlines, partially vacated the five-day evidentiary hearing, but deferred ruling on the merits of the Settlement Agreement.

31. On February 2, 2023, the Commission convened a one-day evidentiary hearing, during which the Commissioners and Commission Counsel questioned certain witnesses. In addition, the Commission admitted Hearing Exhibit (HE) 1500 and all of the documents listed on HE 1500 into evidence. These documents consist of all of the prefiled testimony in the Proceeding, the Settlement Agreement, and attachments, and the CDPHE Emissions Verification Workbooks. In addition, during the course of the hearing, the following hearing exhibits were offered and admitted into the record: HE 144, HE 145, HE 146, HE 147, HE 148, and HE 149.

32. Following the hearing, we directed the parties to file a joint statement of position (SOP) by February 16, 2023, addressing certain topics.[17] As directed, on February 16, 2023, all of the parties to this Proceeding filed a Joint SOP.

33. We conducted our deliberation in this Proceeding at the Commissioners' Weekly Meeting on March 8, 2023.

[16] Issued January 25, 2023.
[17] Decision No. C23-0093, issued February 8, 2023.

C. Black Hills' ERP/CEP and the Settlement Agreement

34. A core element of Black Hills' Application and the Settlement Agreement is the Company's CEP. Although § 40-2-125.5(4)(a), C.R.S., does not require Black Hills to file a CEP because the Company serves less than 500,000 customers, Black Hills—with the support of the parties—states that it has voluntarily elected to make itself subject to § 40-2-125.5, C.R.S., and the requirement to reduce its greenhouse gas emissions by at least 80 percent from 2005 levels by 2030.[18] Black Hills notes that one of the reasons the Company chose to opt into the requirements of § 40-2-125.5, C.R.S., was the statute's Safe Harbor provisions.[19]

35. Black Hills' initial plan targeted emissions reductions of 90 percent—significantly higher than the statute's 80 percent clean air target. In Answer Testimony, however, several parties raised concerns over the costs of the proposed plan. Indeed, Pueblo County, the City of Pueblo, and Cañon City all initially opposed Black Hills' Application due to cost concerns. Answer Testimony from Pueblo County asserted that even though Black Hills' service territory includes some of the poorest communities in Colorado, customers of Black Hills pay significantly more for electricity.[20]

36. In recognition of these cost concerns, the Settlement Agreement achieves estimated cost savings of approximately $100 million compared to the Company's initial proposal.[21] Some of the key cost savings measures in the Settlement Agreement include reducing the targeted emissions reductions from 90 percent to 80 percent and reducing the planning reserve margin from

[18] *See* Settlement Agreement, ¶ 1.
[19] HE 101 (Wagner Direct) Rev. 1, pp. 24-25.
[20] HE 600 (Ortiz Answer), pp. 6-9.
[21] HE 602 (Ortiz Settlement Testimony), p. 12.

24 percent to 20 percent.[22] As stated above, all of the parties—including the three intervening municipalities—now support the Company's plan as modified by the Settlement Agreement.

37. The Company's ERP/CEP proposals, as modified by the Settlement Agreement, represent the Company's attempt to structure Phase II in such a way that the Commission can approve both the Company's CEP and ERP. For instance, the Settlement Agreement sets the inputs and assumptions that will frame Phase II such as the RAP, the price projections for natural gas, the value of the social cost of carbon, and the Company's financial parameters.[23] In addition, the Settlement Agreement establishes the portfolios that will be modeled in Phase II and a 100-point bid scoring and ranking system that considers economic and non-economic factors.[24] The Settlement Agreement also resolves important disputes regarding the model power purchase agreements (PPAs).[25] The parties assert that if the Company's plan meets or exceeds the State's CEP emissions reduction requirements, does not adversely affect system reliability, comes at a reasonable cost to customers, and is found to be in the public interest by the Commission, then the Company's plan is a CEP and qualifies under the Safe Harbor provisions.[26]

38. As noted above, several of the statutory findings required to approve a CEP must wait until Phase II. Among these findings is the determination of whether the 50 percent utility ownership target comes at a reasonable cost and rate impact. When we make this and other Phase II determinations, the Commission will continue to consider the cost concerns raised by various parties, including Pueblo County. In this light, we will strive to avoid any set of bids that results in unnecessary or unreasonable rate impacts.

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[22] *See id.*; Settlement Agreement, ¶ 5.
[23] Settlement Agreement, ¶ 4.
[24] *Id.* at ¶¶ 12, 26.
[25] *See, e.g.*, *id.* at ¶ 25.
[26] *Id.* at ¶ 2.

D. Black Hills' 2023-2026 RES Plan and the Settlement Agreement

39. Black Hills' 2023-2026 RES Plan, as modified by the Settlement Agreement, is also designed to address several new statutory and regulatory requirements.[27] For instance, as of 2020, qualifying retail utilities like Black Hills must have Renewable Energy Credits (RECs) equivalent to at least 30 percent of their retail sales from eligible energy resources, at least 3 percent specifically from distributed generation (DG), and at least half of that 3 percent from retail DG. In addition, in Proceeding No. 19R-0608E, the Commission adopted new rules regarding community solar gardens (CSGs), and the General Assembly passed four bills[28] in 2021 that further impact RES requirements. One of these four bills, SB 21-272, created a new requirement to focus renewable energy investments on low income or income-qualified (IQ) customers and disproportionately impacted (DI) communities.

40. In its Direct Case, Black Hills proposed 12 MW of total incentivized on-site solar capacity, 16 MW of total CSG capacity, and 2.5 MW of estimated off-site solar capacity. Compared to the Company's last RES Plan, these proposals were approximately double the Company's incentivized capacity levels for on-site solar capacity and CSGs.[29] In addition, Black Hills introduced new incentives for storage paired with solar systems and updated its customer choice program.[30]

41. Similar to the Company's ERP/CEP proposals and in line with the cost concerns, the Settlement Agreement generally pares down the components of the RES Plan that do not relate to IQ/DI communities. For instance, the Settlement Agreement proposes only 9 MW of total

[27] HE 101 (Wagner Direct) Rev. 1, pp. 45-46.
[28] Senate Bill 21-261, Senate Bill 21-272, House Bill 21-1266, and House Bill 21-1238.
[29] *Id.*
[30] *Id.*

incentivized on-site solar capacity and 14 MW of total CSG capacity. Of that 14 MW of CSG capacity, however, the Settlement contemplates 6 MW for IQ customers, whereas the Company's initial proposal only contemplated 4 MW for IQ customers.[31] Moreover, the Settlement Agreement includes a minimum of 500 kW per year for donated CSG subscriptions for IQ CSGs. The Settlement Agreement also sets forth a plan for community outreach and engagement of IQ customers and DI communities regarding the Company's RES programming. This IQ/DI community outreach has an annual budget of $15,000.[32]

E. Findings and Conclusions Regarding the Settlement Agreement

42. We commend the parties for reaching a comprehensive, uncontested Settlement Agreement. The Settlement Agreement puts forth an ERP and RES Plan that advance the State's clean energy goals, RES requirements, and provide a reasonable framework for engagement with IQ customers and DI communities, all while mitigating rate impacts. The Settlement Agreement also establishes an important foundation for Phase II in which the Company will issue its RFP, receive, and evaluate bids, and compile the 120-Day Report. Through this process, the Company will be able to use Phase II to implement the requirements for approval of a CEP.

43. In addition, the Settlement Agreement resolves the remaining requests in Black Hills' Motion for Waivers.[33] The requested waivers cover rules governing information Black Hills must provide regarding energy and demand forecasts, how RES incremental costs and avoided costs can be recovered, the appropriate interest rate for the RESA, and the administrative costs the Company can collect in connection with its RES programs. For some items, the Company agrees

[31] Settlement Agreement, ¶ 36; HE 102, Attachment MJH-2, p. 8.
[32] Settlement Agreement, ¶¶ 44-49.
[33] As noted above, in Decision No. C22-0558-I, the Commission granted some of the requested waivers and deferred the rest.

to withdraw the requested waivers, and for the other items the parties agree to the requested waivers outright or with certain conditions.[34]

44. Importantly, the Settlement Agreement also ensures that best value employment metrics (BVEM) will be fully considered in Phase II. In Phase II, bids will be evaluated in part using a 100-point bid scoring process, and a bid's BVEM impacts its 100-point bid evaluation score.[35] Moreover, in Paragraph 27 the Company commits to grade each bid on how it complies with BVEM, advancing only those proposals that are compliant with statutory requirements for these metrics. The Company also commits to advising potential bidders of the required metrics and the scoring and ranking system that it will use and to inform any bidders determined to be noncompliant along with providing the bid BVEM scores. The Company states that it will provide documentation on the compliance metrics and scoring/ranking system in the RFP documents and will make itself available to discuss questions with bidders.[36]

45. The Commission finds that these Settlement Agreement provisions addressing BVEM set the right course for ensuring compliance with Colorado's BVEM requirements. The Settlement Agreement specifically references § 40-2-129(1)(a)-(b) and prohibits the Company from advancing any proposal that fails to comply with the statutory requirements. This ensures that the Phase II portfolios will contain only those bids that provided the requisite BVEM information. In addition, by establishing BVEM as a specific criterion in the 100-point evaluation system, the Settlement Agreement helps ensure that the Commission can consider BVEM when making its Phase II decisions.

[34] Settlement Agreement, ¶ 55.4 ("The Company will withdraw its requested waiver Rule 3660(e)…."); Settlement Agreement, ¶¶ 59-62.
[35] Settlement Agreement, ¶ 26; HE 112 (Thames Rebuttal), pp. 22-23.
[36] Settlement Agreement, ¶ 27.

46. Ultimately, the parties to this Proceeding represent a wide range of interests, including municipalities in Black Hills' service territory, state agencies, consumer advocates, environmental and public interest groups, and trade associations. This diverse set of interests led to a well-litigated proceeding in which several important issues were highlighted. Despite the numerous contested issues, the parties were able to reach a unanimous resolution in a manner that, for the most part, we find to be reasonable. Subject to the clarifications, additions, and modifications set forth below, the Commission approves the Settlement Agreement.[37]

1. 100 MW Preference

47. Paragraph 23 of the Settlement Agreement establishes a preference of bid sizes of approximately 100 MW on any generation project bid into the RFP. The Commission directed the parties to address this 100 MW preference in the SOP. The parties responded that they do not oppose authorizing multiple bidding options under the same bid fee for projects at the same site, reasoning that doing so could help the Commission compare whether the economies of scale impact the pricing of bids as well as the potential differences in costs between independent power producer (IPP) and utility-owned bids.[38] Along these lines, the parties put forth the following:

> (1) bidders should be allowed, but not required, to submit their projects under two different capacity sizes; (2) bidders should be allowed, but not required, to submit both a utility-ownership version (i.e., build-transfer) and PPA-version of their bid for price-comparison purposes; and (3) any bids submitted under these provisions should be limited to only bids for iterations of the same project located at the same site.[39]

[37] In the Settlement Agreement, the parties agree to use the statutory definition of low-income established by SB 21-272 at § 40-2-108(3)(d)(III), C.R.S. While this is an acceptable resolution for this Proceeding given the larger context of the Settlement Agreement, we clarify that in future proceedings where the definition of Income Qualified Customer is at issue, the Commission may reevaluate whether a more appropriate definition is found in § 40-3-106(1)(d)(II).
[38] SOP, p. 14.
[39] *Id.*

48. While the parties are amenable to allowing a bid to include different capacity sizes and ownership versions, they defend the 100 MW preference and oppose an alternative preference that bids provide the "maximum benefit" to customers. The parties argue that it would be difficult to evaluate "maximum benefits" other than the portfolio options and the 100-point economic and non-economic point system set forth in the Settlement Agreement. The SOP asserts that this 100-point system is set up to evaluate economics (worth 75 points) and five non-economic factors, which include transmission issues, developer experience, real property/environmental issues, externality benefits/community support, and BVEM (worth five points each). The parties argue that the 100 MW preference "is that all of these factors must be considered together, and maximizing one at the expense of another would undermine the agreed-upon maximum point allocation for each factor."[40]

49. The parties further defend the 100 MW preference in the SOP, arguing that it (1) mitigates the risk of failed projects; (2) targets more geographical diversity; (3) captures economies of scale; and (4) lends to potentially more diverse generation types (solar, storage, wind, etc.). The parties also reiterate that the 100 MW preference does not mandate a certain size of bid but only sets a preference.[41]

50. Starting with the issue of authorizing multiple bidding options under the same bid fee, we direct Black Hills to amend its RFP consistent with the proposal in the SOP. Bidders will be allowed to submit, under the same bid fee, two different project capacity sizes as well as a utility-owned and PPA-version of the bid, provided that such bids are for the same project located at the same site.

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[40] *Id.* at 13-14.
[41] *Id.* at 11-12.

51. Moving to the 100 MW preference itself, we reject Paragraph 23 of the Settlement Agreement. The parties have not met their burden of showing how this provision is in the public interest. It remains unclear to the Commission how the Company—let alone the IE—would implement the 100 MW preference fairly, transparently, and in a manner consistent with Colorado's competitive ERP bidding process.

52. Not only does the 100 MW preference add uncertainty to the Phase II process, we see little benefit to this provision. For example, the Settlement Agreement establishes a 100-point system for evaluating bids based on economic and non-economic criteria, and those bids that advance past this 100-point system are modeled through a suite of portfolios. If the 100 MW preference is—as the SOP asserts—simply that "all of these factors must be considered together,"[42] then the 100 MW preference is duplicative of other, more transparent, factors such as the 25 points awarded to non-economic factors and the Geographic Diversity Portfolio (Portfolio 5). Moreover, given that the 100 MW preference is not mandatory, it is unclear the extent to which bidders would consider the preference when designing their bids. The potential for the 100 MW preference to mitigate impacts of failed bids is insufficient to change our calculus. We find other components of the ERP—the fact that there will be both utility and IPP bids, backup bids, and the more stringent security requirements—to more appropriately mitigate the risk of failed bids.

2. Demand Side Management and Demand Response Modeling Assumptions

53. Paragraph 4.0 of the Settlement Agreement sets forth various modeling inputs and assumptions for Commission approval, including demand side management (DSM) and demand

[42] *Id.* at 13-14.

response (DR).[43] set forth in the Company's direct case, subject to the Settlement Agreement's modifications.[44] Despite questions at the February 2, 2023 hearing, in the SOP, the parties reiterated their support for using the DR and DSM assumptions set forth in the Settlement Agreement. The parties argue that the DR and DSM assumptions in the Settlement Agreement are reasonably based on the levels that the Commission recently approved in Proceeding No. 21A-0166E.[45]

54. In the context of the larger Settlement Agreement, we find the DSM and DR assumptions set forth in the Settlement Agreement to be reasonable for purposes of this Proceeding. For Black Hills' next ERP, however, we direct the Company to include additional information in its Direct Case to help ensure a more robust analysis of DR. Specifically, Black Hills shall analyze and fully address the suggestions that Staff and WRA put forth during the hearing about including some type of effective load carrying capability value for DR resources, including incremental generic DR resources in Phase I, and putting forth a proposal for how to analyze varying amounts of DR in Phase II.[46] In addition, Black Hills shall evaluate and incorporate, to the extent feasible, the use of third-party aggregated DR as a potential resource solution.

55. These additions to Black Hills' next ERP will help ensure that the Commission and parties better understand the most cost-effective way to move forward with the acquisition of long-term resources. It is important that all parties are better able to evaluate DR resources alongside traditional supply-side resources. The fact that the next ERP will likely evaluate the addition of

[43] Paragraph 4.0 and its subparts do not expressly reference DR. In Rebuttal Testimony, however, the Company maintained that its DSM and load forecasts incorporate the Company's approved DR goals. (HE 111 (Harington Rebuttal) Rev. 1, p. 20).
[44] Settlement Agreement, ¶ 4.
[45] SOP, pp. 6-7.
[46] Hrg. Trans. 2/2/2023, pp. 163-64, 191-92.

fossil fuel generation makes it particularly important that we have a more robust analysis of DR.[47] Especially considering the challenging socio-economic issues within Black Hills' electric territory and the Company's relatively high rates, compared to other Colorado electric providers, it is important that all options to meet peak demand for the future be analyzed fully to ensure the best value for ratepayers in both the short- and long-term.

3. Performance Incentive Mechanism

56. During the February 2, 2023, hearing, the Commissioners asked several questions regarding the potential for developing a performance incentive mechanism (PIM) focused on utility-owned generation assets. Subsequently, the Commission directed the parties to address in the SOP their suggested approach and timing for a stakeholder process to develop a PIM on utility-owned generation.

57. In the SOP, the parties argue against establishing a PIM in this Proceeding, arguing that "the evidentiary record is not sufficiently developed to direct or approve any PIMs at this stage."[48] The parties further argue that requiring a PIM for only utility-owned projects risks creating an uneven playing field, which could frustrate the intent of the 50 percent utility ownership target in SB 19-236. The SOP states that other parties are hesitant to accept a PIM without having more information about which bids are chosen, and how the PIM would work with each such bid.[49] However, the parties leave open the possibility of a PIM being introduced in future CPCN proceedings once more information is known about the selected portfolios. The SOP states that in

[47] *See* HE 103 (Thames Direct) Rev. 1, pp. 27-28 (noting that a long-term PPA to acquire all of the energy and capacity from two 100 MW natural gas-fired units will expire in 2031, just after the end of the RAP in this Proceeding).
[48] SOP, p. 15.
[49] *Id.* at p. 15-16.

any future CPCN for Company-owned generation to be acquired under the approved CEP, all participating parties should be able to present or oppose a PIM.[50]

58. The Commission directs the parties to engage in a stakeholder process in this Proceeding for the development and submission of two PIMs: (1) an emissions reduction PIM and, (2) a utility-owned generation PIM. The following deadlines and procedures shall apply to the stakeholder process such that the parties can develop PIM proposals contemporaneously with Phase II:

- The stakeholder process will be initiated by the Company 15 days after the filing of the 120-Day Report.
- The Company will file the PIM proposals with the Commission 60 days after the filing of the 120-Day Report with supporting testimony.
- A 30-day comment period will commence upon the PIM proposal filing for responses to the PIM proposal for any interested ERP parties (Proceeding No. 22A-0230E) that would like to comment on the PIM proposal:
  - If no protests are filed, the Commission attempt to rule on the PIMs within 60 days after filing of the PIM proposal, schedule permitting.
  - If protested, the Commission will attempt to conduct a limited and expedited hearing within 30 days of comment deadline, schedule permitting. If feasible, the Commission will attempt to issue a decision on any PIM within 30 days of such hearing.
    - There will be no discovery process regarding the PIM proposals.

59. By using the stakeholder process outlined above, parties will be able to develop PIM proposals after the Company issues the 120-Day Report. This should ameliorate the concerns about developing a PIM in the absence of information about the selected bids.

60. While we encourage the parties to use the stakeholder process outlined above to work out the details of the PIM proposals, the PIM proposals must adhere to the parameters set

[50] *Id.* at p. 16.

forth in this Decision. Specifically, for the emissions reduction PIM, the baseline will be the cost, level, and timing of expected emissions from the approved Phase II portfolio. The PIM must incentivize deeper or quicker reductions in greenhouse gas emissions and disincentivize the opposite. Likewise, the PIM must reward greenhouse gas emissions reductions that are achieved at less cost than what the approved portfolio anticipates and must penalize the opposite. In other words, this emissions reduction PIM must not only incentivize deeper and quicker emissions reductions, it must account for the relative costs of those emissions' reduction. Finally, we emphasize that the PIM should in no way threaten reliability of Black Hills' system.

61. Regarding the utility-ownership PIM, the PIM shall track the expected costs of any utility-owned generation projects that are included in the approved portfolio. Such costs shall consider both capital costs and operations and maintenance (O&M) expenses and anticipated availability. The expected costs that were assumed in Phase II shall be compared to the final cost of the project after construction is complete and it begins operating. The PIM shall incentivize final capital, O&M, and availability costs that are lower than what was assumed in the Phase II bid and disincentivize final costs that are higher than what the Phase II bid assumed. In general, this utility-ownership PIM is intended to incentivize the Company to submit accurate bids and to control the costs on any utility-owned project that is selected. This PIM is not meant to incentivize the Company to build more utility-owned projects.

62. In directing the parties to develop this utility-ownership PIM, we are unpersuaded by arguments put forth in the SOP that such a PIM would create an unequal playing field or somehow frustrate the intent of the 50 percent utility ownership target. In contrast, we see such a PIM as helping to level the current playing field as between utility and IPP bids. As it is, IPPs will likely be held to their Phase II bid price and could risk losing their security for the project if it

cannot go forward under the initial price. Unlike an IPP bid, however, a utility-owned project generally follows Phase II with a separate CPCN proceeding in which costs for the project could significantly increase. To ensure that the Company is held to its estimated costs in its Phase II bid, it is necessary for the utility-ownership PIM to be developed and applied in this Proceeding, as opposed a later CPCN proceeding. This partial alignment of utility incentives to help encourage reasonable cost is of particular importance in this process given the concerns raised by Pueblo County and others about Black Hills having some of the highest electric rates in the state while serving communities with specific socioeconomic challenges.

4. Additional CSG Reporting

63. In our decision ordering a joint SOP, one of the items we directed the parties to address was Black Hills' plans to use the Inflation Reduction Act (IRA) incentives in connection with new CSG capacity acquisitions.[51] In the SOP, the parties state that CSG developers will be heavily incentivized to capture any federal incentives in their bid pricing. The Company also notes that it has not requested approval to own or operate any CSG capacity, but if that changes during the pendency of the RES Plan, Black Hills will report any IRA funds that it applies or receives related to CSG programing.[52]

64. The Settlement Agreement already contains provisions requiring Black Hills to provide information on CSG participation through its annual RES reporting.[53] We see no need to modify these provisions. In light of the rapidly evolving understanding of the opportunities that the IRA provides, however, we will require additional reporting on this topic. Specifically, as part of the Company's annual RES reporting, Black Hills shall describe how IRA incentives impacted

[51] Decision No. C23-0093-I issued February 8, 2023, p. 2.
[52] SOP, pp. 10-11.
[53] Settlement Agreement, ¶ 49.3.

the bid prices that came in, and to what extent the bidders were able to take advantage of various components of the IRA. It is our expectation that the Company will work with CSG bidders to acquire the necessary information prior to the annual reports.[54]

5. Additional Sensitivities

65. In the Settlement Agreement, the Company commits to run a DR sensitivity on its Preferred Portfolio.[55] The Commission directed the parties to address in the SOP their position on running the following two additional sensitivities: (1) high and low natural gas prices (and corresponding wholesale market power prices), and (2) extreme summer and winter weather events like Storm Uri as recommended by Staff.[56]

66. In the SOP, Black Hills states that, while it does not believe them to be entirely necessary, the Company "remains open to modeling high and low gas sensitivities and extreme summer and winter sensitivities on its Preferred Portfolio should the Commission desire."[57] The parties in the SOP go on to propose the following parameters for these additional sensitivities:

> (1) a high and low gas price case, based on Hitachi's 2022 Fall Reference Case, with corresponding wholesale market power prices; and, (2) for the "extreme weather sensitivities," (i) updating the load assumptions for July 2030 to that of the "high load case" used in the Company's base ERP/CEP modeling (an increase of approximately 20 MW and 9,734 MWh), (ii) updating the December 2030 load assumptions to reflect the ratio of July to December forecast (an increase of 15 MW/74 percent of July and 8,161 MWh/84 percent of July), and (iii) reducing the wind generation assumptions for each the July 2030 and December 2030 extreme weather sensitivity by ten percent.[58]

[54] To be clear, this IRA reporting shall be in addition to the reporting that the Settlement Agreement already requires.
[55] Settlement Agreement, ¶ 13.
[56] Decision No. C23-0093-I, p. 2.
[57] SOP, p. 5.
[58] *Id.*

67. Citing time and resource constraints during Phase II, the parties ask that these sensitivities only apply to the Preferred Portfolio.[59]

68. In addition to the DR sensitivity set forth in the Settlement Agreement, the Commission directs Black Hills to model the high and low gas sensitivities and extreme summer and winter sensitivities on the Preferred Portfolio, consistent with the parameters set forth in the SOP. These sensitivities could provide important insights into the how the Company's Preferred Portfolio could function under circumstances for which—even though extreme—the utility should be prepared.

6. Study on Correlated Outage from Fuel Supply Disruptions

69. The Pueblo Airport Generating Station (PAGS) is a critical piece of Black Hills' generating fleet. The various gas units collocated at PAGS provide over 400 MW of capacity and have both black start and quick ramping capabilities that can closely follow the Company's load, net of renewable generation.[60]

70. As indicated above, a key Phase II input that the Settlement Agreement establishes is a 20 percent planning reserve margin.[61] At the February 2, 2023 hearing, Company witness Arne Olson indicated that the reliability studies conducted to evaluate the appropriate planning reserve margin treated all forms of thermal unit outages as independent.[62] He went on to explain that a utility could perform a "resilience study projection" or a case study looking at what would happen if something like a fuel supply disruption occurred that would cause a correlated outage at

[59] *Id.* at pp. 5-6.
[60] HE 101 (Wagner Direct) Rev. 1, pp. 20-21.
[61] Settlement Agreement, ¶ 10.1.
[62] Hrg. Trans. 2/2/2023, p. 145.

PAGS. Mr. Olson indicated that it could be beneficial to know how the system would perform under such a circumstance.[63]

71. The Commission is concerned that a correlated outage at PAGS could have significant impacts and that little has been done to analyze this risk. Accordingly, we direct the Company to conduct or commission a study to assess the degree of risk and potential mitigation options for gas supply disruptions—including gas shortages—that result in a correlated outage at PAGS. This correlated outage study must evaluate extreme winter and summer situations that might constrict fuel availability in the area such that the performance of the gas units at PAGS is jeopardized. This study should also assess the ability of on-site storage or power imports via Black Hills' existing and planned transmission interconnections with neighboring systems to support reliability during a gas supply disruption and should evaluate the potential costs of any approaches to ameliorate the risk of gas supply disruptions.

72. Although this correlated outage study is important to better understand the firmness of the power supply that PAGS provides, we do not need to consider the results of the study for purposes of our Phase II decision in this Proceeding. In order to reduce the burden this directive places on the Company during the Phase II process, Black Hills has 12 months within which to file the correlated outage study.

7. Clarifications to the Settlement Agreement

73. There are a handful of provisions in the Settlement Agreement that we approve subject to certain clarifications. For instance, Paragraph 7 discusses the 50 percent utility ownership target and indicates that the determination of reasonable costs should be bound by the

[63] Hrg. Trans. 2/2/2023, pp. 149-51.

range of bids advanced to modeling. We clarify that this provision does not restrict what the Commission can consider when we determine whether the utility ownership target comes at a reasonable cost and rate impact per § 40-2-125.5(5)(b), C.R.S.

74. Paragraphs 34 through 43 of the Settlement Agreement set forth various components of the Company's RES Plan. In response to Commission inquiries, in the SOP Black Hills further explains how the Company will track RECs in the context of § 25-7-105(e)(VIII)(H), C.R.S., what the minimum level of CSG purchases should be per § 40-2-127(5)(a)(IV), C.R.S., and how the incentives under the IRA will work with the CSG programs.[64] The Commission approves Paragraphs 34-43 of the Settlement Agreement with the expectation that the Company will implement the plans set forth in the SOP regarding tracking RECs, the minimum level of CSG purchases,[65] and the incentives under the IRA related to CSG programs.

75. Similarly, in response to Commission inquiries, Black Hills describes in the SOP how it will prospectively implement interest at the Company's weighted average cost of capital on over and under collected RESA balances per Paragraph 55.4 of the Settlement Agreement.[66] We find the Company's explanation on this issue to be reasonable. Accordingly, the Commission approves Paragraph 55 of the Settlement Agreement and its subparts with the expectation that the Company will implement the interest rate on the RESA as described in the SOP.

76. Finally, Paragraphs 51 through 54 and its subparts establish certain parameters for cost recovery and a Phase II process in which Black Hills will present for evaluation various cost

[64] SOP, pp. 7-11.
[65] Per the SOP, the parties propose that the minimum purchases of electrical output from newly installed CSGs should be set at 2 MW, which could be achieved through any combination of RFP and Standard Offer. The parties argue that this minimum level balances developer and customer interest with overall costs of the program. (SOP, p. 10). Consistent with the SOP, we agree that 2 MW is a reasonable minimum. (For clarity, the maximum purchases are the CSG levels specified in the Settlement Agreement).
[66] SOP, p. 8.

recovery approaches. Paragraph 53.3 states that Black Hills is authorized to transfer up to 50 percent of any RESA surplus to the CEP Rider. The Commission finds that Paragraphs 51-54 and its subparts are reasonable and approve them. We clarify, however, that approval of Paragraph 53.3 does not thereby authorize the Company to use the RESA surplus for CEP purposes. Rather, consistent with § 40-2-125.5(4)(a)(VIII), C.R.S., the Commission will determine whether Black Hills can use the RESA surplus for CEP purposes in Phase II when we evaluate the Company's preferred cost recovery method.

F. Additional Findings and Conclusions

77. The Settlement Agreement is comprehensive. However, it is necessary to render findings and issue directives related to a handful of issues outside of the Settlement Agreement to ensure that Phase II of the ERP/CEP proceeds efficiently.[67]

1. Independent Evaluator

78. On May 27, 2022, Black Hills filed a Motion for IE Approval. However, in Decision No. C22-0588-I,[68] the Commission deferred ruling on Black Hills' Motion for IE Approval because Black Hills had not yet negotiated a scope of work with Accion Group, LLC (Accion), its proposed IE. The Commission directed Black Hills to file a scope of work contract pursuant to Rule 3612(b) before the scheduled start of the evidentiary hearing.

[67] One of the issues that the Settlement Agreement does not expressly address is the workforce transition and community assistance plans associated with the early retirement of the Pueblo Diesel units. (*See* Settlement Agreement, ¶¶ 8-9 and its subparts). This issue was, however, addressed in Direct and Answer Testimony. (HE 102 (Harrington Direct) Rev. 1, pp. 41-42; HE 300 (England Answer), pp. 12-13). The parties affected by the Pueblo Diesel units' early retirement—such as the City of Pueblo and Pueblo County—have not raised any concerns with the information Black Hills put forth.

[68] Issued September 21, 2022

79. On January 19, 2023, Black Hills filed the required IE scope of work contract. The Company states that it previously conferred with Staff and the UCA and that both of these intervenors agree to the IE scope of work and now support Black Hills' Motion for IE Approval filed on May 27, 2022.[69] Black Hills asserts that the scope of work is aligned with the Commission's rules and notes that the projected cost of the IE's services is roughly $249,000.[70]

80. The scope of work contract that Black Hills submitted fails to address important regulatory requirements. For example, Rule 3612(b) states that the terms of the IE contract that the Commission approves must prohibit the IE from assisting any entity making proposals to the utility for subsequent resource acquisitions for three years. Similarly, Rule 3612(d) requires the IE to maintain a log that briefly identifies the entities communicating with the IE and summarize the timing and substance of the communications, Rule 3613(e) establishes the requirements for the IE Report.

81. Black Hills shall revise the IE scope of work contract to incorporate the necessary regulatory requirements, including those in Rule 3612(b), 3612(d), and Rule 3613(e). The Company shall again confer with Staff and the UCA regarding the revised scope of work contract and file the revised scope of work after the parties have reached a consensus. The Commission will consider whether to approve Accion as the IE for this Proceeding when we evaluate the revised scope of work. Black Hills must not issue the RFP and commence Phase II until the Commission has approved an IE and the associated scope of work.

[69] Notice of Filing Scope of Work Contract, p. 2.
[70] Scope of Work Contract, p. 12.

2. Rule 3612(f) Procedural Conference

82. Rule 3612(f) contemplates that the Commission preemptively schedule a conference to establish a procedure through which the parties can ask questions about the IE's filings. Given the Phase II procedures for bid evaluation and selection that the parties agreed upon in the Settlement Agreement, however, the Commission sees no need to preemptively schedule a procedural conference that might be unnecessary. Instead, any party that desires to ask questions about the IE's filings must first file a motion requesting authorization. Upon receipt of such a motion, the Commission will consider whether there is good cause for such questions and will, if necessary, schedule the procedural conference contemplated in Rule 3612(f).

3. Securitization Analysis for Pueblo Diesel Units

83. Section 40-2-137, C.R.S., requires a securitization analysis when an ERP contemplates the retirement of a generating facility.

84. The Settlement Agreement calls for the accelerated retirement of the Pueblo Diesel units (to retire in 2026 instead of 2029).[71] Accordingly, Black Hills shall include a securitization analysis in the 120-Day Report, as necessary to ensure compliance with § 40-2-137, C.R.S. Assuming the Preferred Portfolio contains the early retirement of the Pueblo Diesel units, the Company shall include in the 120-Day Report the net present value revenue requirement (NPVRR) of the Preferred Portfolio assuming the Pueblo Diesel units are securitized and the NPVRR of the Preferred Portfolio assuming the Pueblo Diesel units are *not* securitized.[72]

[71] Settlement Agreement, ¶ 8.
[72] The Commission recognizes that the Pueblo Diesel units are mostly depreciated and will have a relatively small net book value at the time of their accelerated retirement. We will be mindful of this context when we evaluate Black Hills' securitization analysis in the 120-Day Report.

4. Disclosure of Phase II Modeling Inputs

85. In Section 3 and Appendix I of HE 102, Attachment MJH-1, Rev. 1, Black Hills lists the key assumptions and inputs that the Company will use for Phase II. As set forth in the Settlement Agreement and in Black Hills' Direct Testimony, the Company plans to update several of these modeling inputs after the Phase I decision (*e.g.*, gas price forecasts, market prices, DSM assumptions, etc.).[73]

86. Black Hills shall file, prior to issuing the all-source RFP, a complete list of the modeling inputs and assumptions consistent with the presentation in Section 3 and Appendix I of HE 102, Attachment MJH-1, Rev. 1 and indicate which parameters were updated for bid evaluation and selection purposes. To the extent that any parameters must be updated after the RFP is issued but prior to the Phase II resource evaluation, the Company shall identify the parameters in the list that need to be updated after the RFP and provide the updated values in the 120-Day Report.[74] These updates must be consistent with our other rulings in this Phase I Decision.

5. CDPHE Verification Requirements

87. In Decision No. C22-0494-I,[75] the Commission granted CDPHE's request for limited participation as a "neutral verifier." The Commission directed CDPHE to file its Phase II Verification Report within 30 days of the 120-Day Report that Black Hills must file per Rule 3613(d). Decision No. C22-0494-I further states that the Commission will be permitted the opportunity to seek additional verification reporting from CDPHE and request technical clarifications.[76]

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[73] *See e.g.*, HE 102, Attachment MJH-1, Rev. 1, p. 141; Settlement Agreement, ¶ 4.1.
[74] Black Hills should be prepared to explain why any such parameters could not be updated prior to the RFP issuance.
[75] Issued August 18, 2022.
[76] Decision No. C22-0494-I, pp. 7-8.

88. We direct Black Hills to coordinate with CDPHE during the course of Phase II to ensure that the appropriate verifications are submitted.

6. Phase II Reporting for Public Interest Findings

89. Section 40-2-125.5(4)(d), C.R.S., requires the Commission to make certain public interest findings. With regard to these public interest findings, one of the factors that the Commission must consider is "[w]hether the [CEP] will result in a reasonable cost to customers, as evaluated on a net present value basis."[77] Subsection (4)(d)(III) goes on to state: "In evaluating the cost impacts of the clean energy plan, the commission shall consider the effect on customers of the projected costs associated with the plan as set forth in subsection (4)(a)(VI) of this section as well as any projected savings associated with the plan, including projected avoided fuel costs." Subsection (4)(a)(VI) states: "The clean energy plan must set forth the projected cost of its implementation and anticipated reductions in carbon dioxide and other emissions."

90. To ensure the Commission can make the required public interest findings in Phase II, including whether the CEP results in a reasonable cost to customers as evaluated on a net present value basis, we direct Black Hills to clearly delineate in each optimized portfolio the various categories of costs and savings set forth in the statute. Black Hills should also do this for the Phase II base ERP portfolio.

[77] § 40-2-125.5(4)(d)(III), C.R.S.

II. ORDER

A. The Commission Orders That:

1. The Application for Approval of a 2022 Electric Resource Plan (ERP) and Clean Energy Plan (CEP) and a 2023-2026 Renewable Energy Standard (RES) Compliance Plan filed by Black Hills Colorado Electric, LLC (Black Hills) on May 27, 2022, is granted, in part and with modifications, consistent with the discussion above.

2. The Unopposed Motion to Approve the Unanimous Comprehensive Settlement Agreement filed by Black Hills on January 13, 2023, is granted, in part, consistent with the discussion above.

3. Black Hills' 2022 ERP is approved as modified by the Unanimous Comprehensive Settlement Agreement and by this Decision.

4. Black Hills is authorized to use Phase II of this Proceeding to further implement the requirements for approval of its CEP in accordance with Senate Bill 19-236.

5. Black Hills shall issue the Requests for Proposals for an all-source, competitive bidding process to meet its resource need, consistent with the discussion above.

6. Black Hills shall conduct or commission a study to assess the degree of risk and potential mitigation options for gas supply disruptions—including gas shortages—that result in a correlated outage of the generating units at the Pueblo Airport Generating Station and shall file this correlated outage study within 12 months, consistent with the discussion above.

7. Black Hills' 2023-2026 RES Compliance Plan is approved as modified by the Unanimous Comprehensive Settlement Agreement and by this Decision, consistent with the discussion above.

8. The Motion for Waivers and Variances that Black Hills filed on May 27, 2022, is granted, in part, consistent with the discussion above.

9. The Motion for Approval of an Independent Evaluator and Partial Waiver of Commission Rule 3612(a) filed by Black Hills on May 27, 2022, is granted, in part and with modifications, consistent with the discussion above. Black Hills shall revise the Independent Evaluator's scope of work contract to incorporate the necessary regulatory requirements, confer with Staff of the Colorado Public Utilities Commission and the Colorado Office of Utility Consumer Advocate regarding the revised scope of work contract, and file the revised scope of work after the parties have reached a consensus.

10. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

11. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING March 8, 2023.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

ATTEST: A TRUE COPY

G. Harris Adams,
Interim Director