Black Hills Energy: Ready to Serve

Colorado Clean Energy Plan

Electric Resource Plan

September 11, 2026

Black Hills Energy
Ready

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(4 *CODE OF COLORADO REGULATIONS* ("CCR") 723-3 - PART 3 RULES REGULATING ELECTRIC UTILITIES 4 CCR 723-3-3600)
3600 Electric Resource Planning

Rule	Description	Location in Report
3603 Resource Plan Filing Requirements		
3603(a)	Plan required to be filed by October 31, every four years. The Company's last ERP was filed May 31, 2022	This Plan is being filed by September 11, 2026
3603 (b)	Motions for highly confidential information to be filed at the same time	Motions filed. Section 11.0
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3604 (b)	Forecast developed pursuant to rule 3606	Section 4.0
3604 (c)	Evaluation of existing resources pursuant to rule 3607	Section 5.1
3604 (d)	Evaluation of transmission resources pursuant to rule 3608	Section 7.0
3604 (e)	Reserve margins and contingency plans pursuant to rule 3609	Section 3.3 – Reserve Margins. Section 9.0 – Contingency Plan
3604 (f)	Assessment for need for additional resources pursuant to rule 3610	Section 8.0
3604 (g)	Plan for acquiring needed resources pursuant to rule 3611 and emissions	Section 8.10
3604 (h)	Water consumption	Section 15.0
3604 (i)	Proposed RFPs and model contracts	Appendix N
3604 (j)	Identification of confidential and highly confidential information	See motions filed. Section 11.0
3604 (k)	Three alternate plans	Section 8.0
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3606 (d)	Data comparison – five years of historical data; last ERP	Section 4.7
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Colorado PUC ERP Filing Requirements

Order Reference	Description	Location in Report
Decision No. C23-0193, Proceeding No. 22A-0230E	Conduct a new PRM study for 2026 ERP	Section 3.2, 6.6 & Section 2 of Highly Confidential Appendix F
Decision No. C23-0193, Proceeding No. 22A-0230E	Determine whether the 1-day-in-10-year loss of load expectancy continues to be a reasonable and appropriate basis on which to develop Black Hills' PRM	Section 3.2 & 6.6 & Section 2.4.1.2 of Highly Confidential Appendix F
Decision No. C23-0193, Proceeding No. 22A-0230E	Determine what the appropriate PRM would be for an increase in LOLE (i.e., what is the required PRM for a 48-hours-in-10-year LOLE)	Section 6.6 & Table 2-7 of Highly Confidential Appendix F
Decision No. C23-0193, Proceeding No. 22A-0230E	Determine the impact of any regional market developments on Black Hills' proposed PRM	Section 6.7 & Section 2.4.1.3 Highly Confidential Appendix F
Decision No. C23-0193, Proceeding No. 22A-0230E	Black Hills must model, as a sensitivity, the inclusion of at least 100 MW of outside support from neighboring utilities (i.e., short-term market purchases)	Section 6.6 & Section 2.4.1.3 of Highly Confidential Appendix F
Decision No. C23-0193, Proceeding No. 22A-0230E	For Black Hills' next ERP, the Company shall analyze and fully address some type of effective load carrying capability value for DR resources including incremental generic DR resources in Phase I, and put forth a proposal for how to analyze varying amounts of DR in Phase II. In addition, Black Hills shall evaluate and incorporate, to the extent feasible, the use of third-party aggregated DR as a potential resource solution	Section 2.1, 3.6, 6.5 & Hearing Exhibit 104, Direct Testimony of Maria K. Garduna

Waiver from commission rule 3606(a)(II)	Load and demand forecast information at the class level - the Company is willing to commit to providing this level of information as part of its next ERP	Section 4.0 & Confidential Appendix B
3606(a)(V)	Allocation of losses to transmission and distribution components - the Company is willing to commit to providing such information as part of its next ERP filing	Section 4.4, Appendix I & J
3606(a)(VI)	Load profile graphs at the class level - the Company is willing to commit to providing such information as part of its next ERP filing	Appendix D
SB 26-142	The bill requires investor-owned electric utilities (utilities) to identify small-scale geothermal projects and large-scale geothermal projects (geothermal projects). The utility must solicit proposals for the development of small-scale geothermal projects of up to 25 megawatts of net electric generating capacity and large-scale geothermal projects that are greater than 25 megawatts of net electric generating capacity. The utility may submit the proposals to the public utilities commission as part of the utility's next electric resource planning filing. A utility may also partner with a specific customer or group of customers to develop geothermal projects if the specific customer agrees to certain conditions, such as covering at least 50% of the cost of development of the project.	Hearing Exhibit 102, Direct Testimony of Amanda M. Thames

Executive Summary

Black Hills Colorado Electric, LLC d/b/a Black Hills Energy ("Black Hills", "BHCOE", or "the Company") presents this 2026 Electric Resource Plan ("ERP") and Clean Energy Plan ("CEP") (collectively, the "Ready to Serve Plan" or the "Plan") to the Colorado Public Utilities Commission ("Commission"). The Plan is designed to support Colorado's clean energy requirements while maintaining reliable electric service for customers.

Our Ready to Serve Plan provides a pathway to achieve the targeted emission reductions while strengthening reliability. As an early leader in transitioning away from coal combustion generation and toward clean energy resources, Black Hills strategically phased in incremental renewable generation facilities, Busch Ranch and Peak View wind generation, which will assist the Company in meeting the State of Colorado's greenhouse gas ("GHG") emission goals while supporting the continued reliability and resiliency of our system.

Leadership in emissions reduction is nothing new for Black Hills – we retired our last Colorado coal plant in 2013, becoming the first electric utility fleet in the state to be coal-free. Over the past thirteen years, the Company has replaced its emission-intensive coal plants with lower emission natural gas generation and wind generation while maintaining system safety and reliability. The Commission also approved our 2022 Clean Energy Plan, which called for a 50 MW Battery Energy Storage System and a 200 MW solar facility.

Black Hills has a flexible and relatively new generation fleet, enabling the Company to reduce its greenhouse gas emissions in a phased-in approach, adding low- and no-emissions generation resources in a prudent and responsible manner. The success of adding incremental intermittent renewable generation lies with the Company's firm dispatchable natural gas facility (Pueblo Airport Generating Station). A large portion of this facility is under contract through 2031, thus a critical component of this Ready to Serve Plan is the need for firm dispatchable resources, which are required to continue the strategic incremental renewable energy integration.

Our Ready to Serve Plan builds on the previously approved 2022 Clean Energy Plan and proposes an 80 percent reduction in carbon dioxide emissions from 2005 levels by 2030. We've also taken a closer look at reliablity needs as we continue to incorporate renewable energy. To achieve the emission reduction goals and strengthen reliability needs, we need about 300 megawatts ("MW") of new clean energy resources to serve our customers, including wind and battery storage. Our Preferred Plan also address the need for about 125 MW of firm dispatchable natural gas. This Preferred Plan strikes a balance to deliver low cost to customers, while addressing emissions reductions, and resource adequacy needs. Figures ES-1 and ES-

2 depict the Company's capacity and energy mixes as we continue our reliable and clean transition to 2030 and beyond.

Figure ES-1
Projected Capacity Mix

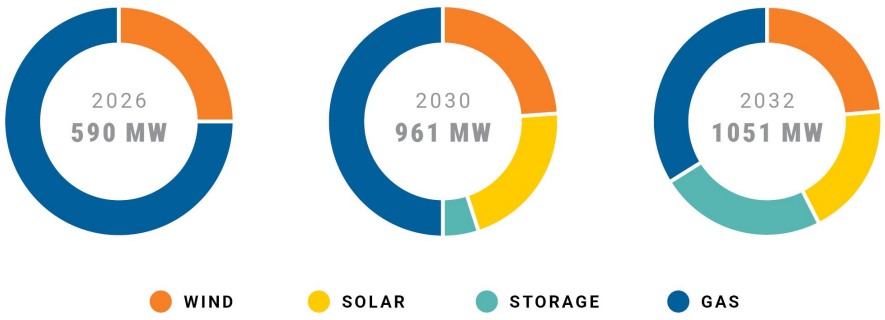
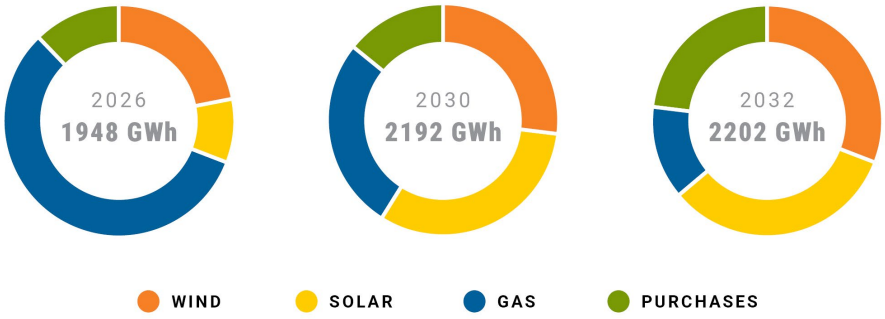


Figure ES-2
Projected Energy Mix

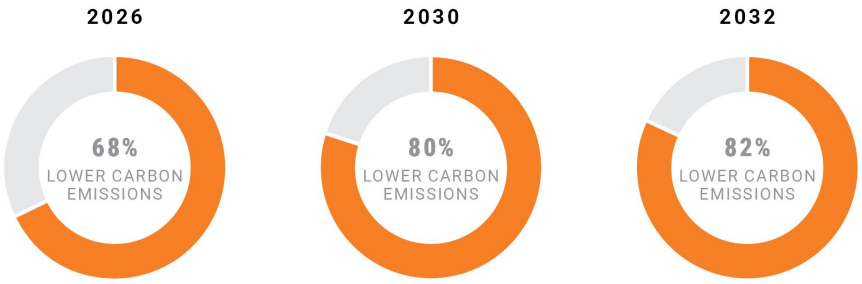


Preferred Plan

Through this Plan, the Company is seeking Commission approval of generation decisions for the seven-year time frame of the Resource Acquisition Period ("RAP"), running through 2032. The Preferred Plan includes resource additions of the following: 98 MW of wind, 126 MW of natural gas, and 200 MW of battery energy storage systems by 2032. These resources will allow the Company to achieve emissions reductions, compared to 2005 levels, of 80% by 2030. Consistent with the traditional resource planning process in Colorado, the Company proposes to

undertake an all-source request for proposal process, where it will solicit and then evaluate competitive bids to develop a preferred resource portfolio that achieves Black Hills' desired outcomes. As a snapshot of the Company's transition to a clean energy future, Figure ES-3 shows the Company's changing resource mix from year 2026 to year 2032.

Figure ES-3
Projected Emissions Reductions Mix



The Company's ability to add new renewable resources through the Ready to Serve Plan is possible in large part due to the flexibility provided by the Pueblo Airport Generating Station ("PAGS"). The PAGS facility, located in Pueblo, includes 220 MW of utility-owned natural gas generation; and 200 MW combined-cycle units that provide capacity and energy to Black Hills through a long-term power purchase agreement, which expires at the end of this resource acquisition period. This 200 MW facility is and will remain critical to ensure Black Hills is able to reliably increase intermittent renewable generation into the portfolio. In particular, the PAGS facility provides critical firm dispatchable capacity services that ensure our customers have energy when they need it. When the sun stops shining and the wind stops blowing, PAGS provides assurance our customers can depend on, standing by ready to reliably and cost-effectively serve them. The continued operation of PAGS or other firm dispatchable resources is a critical component of the Ready to Serve Plan. Similarly, battery energy storage systems will economically address the capacity shortfall while providing fast low-cost energy compared to other alternatives. Wind resources selected in the plan will offer a pathway to meet emissions reduction targets. Together these resources offer a cost-effective balanced portfolio.

Scenario Analysis

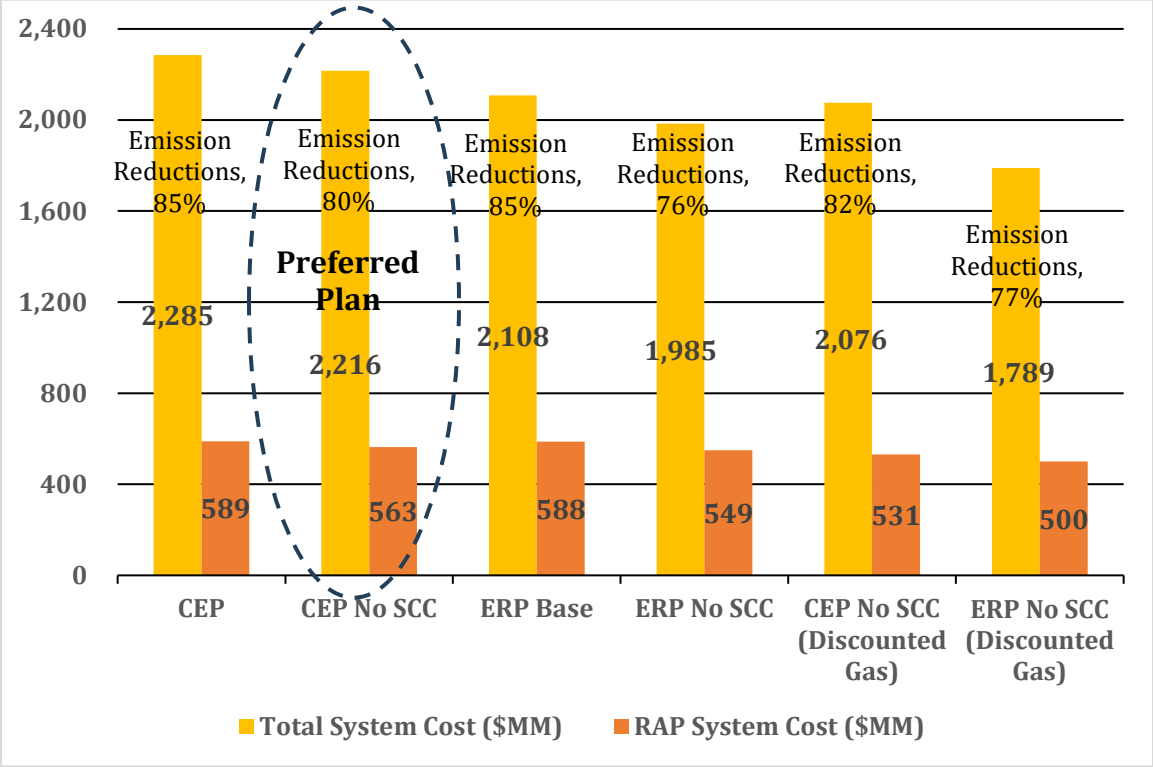
The Company engaged in scenario analysis that derives various resource plans under different future conditions in an effort to support thoughtful consideration of various pathways to achieve Colorado's emission reduction goals, address capacity shortfalls, and strengthen reliability while minimizing cost to customers. In preparing the Plan,

the Company prepared 14 such different scenarios. The scenarios include variations in inputs representing the significant sources of portfolio cost variability and risk. Notably, two scenarios include futures characterized by increased electrification as well as futures without dispatchable natural gas resources, both of which are associated with higher costs. In addition, the Company has applied values representing the social cost of carbon ("SCC") and the social cost of methane ("SCM"), consistent with legislation.[1] Other scenarios represent the following: high gas & low gas assumptions, and future discounted gas scenarios representing potential cost savings to customers through selection of previously constructed gas resources.

The results of the key scenarios are shown in Figure ES-4 which compare the different resulting Present Value of Revenue Requirements ("PVRR") over the entire 2026-2050 planning period. Black Hills recommends the Clean Energy Plan No SCC scenario as the Preferred Plan. This portfolio cost-effectively advances Colorado's state policy objectives while addressing resource adequacy needs, maintaining system reliability and dispatchability, and minimizing customer costs. This Plan identifies renewable resources that reduce emissions, while energy storage and natural gas generation provide the reliable, dispatchable energy necessary to support system reliability. As demonstrated in the Gas Alternative Scenarios, potential discounted natural gas generation resources could also provide additional customer savings if selected through the Company's Phase II RFP process.

[1] Please note that the Company's scenario modeling using the SCC and SCM did not include any modeling where only the SCC or only the SCM was used. In scenario names that include "SCC" in the name, this refers to both SCC and SCM collectively.

Figure ES-4
Base ERP and Key *Scenarios – Deterministic PVRRs (2026-2050)*
25 Year PVRR ($MM)



Utilities must plan for future customer needs for electricity in an environment of significant uncertainty. Thus, the analysis conducted for the Plan examined resource needs under a variety of possible future conditions. A wide range of uncertainties in demand, energy, electric prices, fuel prices, and social cost of emissions were examined. With the Company's presentation of these different scenarios, the Commission and stakeholders will have ample information to consider the Company's appropriate resource needs.

1.0 Introduction

The Company is filing this Ready to Serve Plan pursuant to the Electric Resource Planning Rules, 4 CCR 723-3-3600 *et seq.* ("ERP Rules"). Traditionally, an Electric Resource Plan is intended to evaluate a utility's energy and capacity needs in light of its load forecasts, to achieve a resource mix to reliably serve customers. Uniquely, Black Hills' Ready to Serve Plan also contains the additional elements of a Clean Energy Plan, as set forth in Senate Bill ("SB") 19-236, codified in § 40-2-125.5, Colorado Revised Statutes ("C.R.S."). The clean energy targets are: (1) reducing carbon dioxide ("CO_2") emissions associated with electricity sales to the Company's electric customers by at least 80 percent in year 2030 from 2005 levels, and (2) by 2050, or sooner if practicable, seeking to achieve the goal of providing energy generated from 100 percent clean energy resources, provided doing so is technically and economically feasible and in the public interest. The Ready to Serve Plan thus represents a framework for addressing both the Commission's ERP requirements and the State's CEP requirements.

Black Hills is submitting this Ready to Serve Plan pursuant to House Bill 19-1261 and Senate Bill 19-236. These complementary pieces of legislation established emission reduction goals and regulatory requirements for the filing of a Clean Energy Plan. The Ready to Serve Plan is consistent with State policy, as well as its clean energy commitments to its customers. To assist the Company in preparing it's Ready to Serve Plan, the Company is using resource planning models developed with the assistance of a third-party consulting firm, Energy & Environmental Economics ("E3"). Specifically, Black Hills retained E3 to complete the modeling work necessary for the Ready to Serve Plan, including use of the PLEXOS resource planning model to evaluate the capacity needs while adhering to regulatory and Clean Energy Plan requirements.

The Company will follow the Commission's well-established two step process. The first step, known as Phase I, includes developing a load forecast, evaluating the utility's current resources (including transmission), determining the need for additional resources, and proposing a plan to acquire the resources necessary to meet the identified need. Phase I will conclude with a final Commission decision approving the assumptions and the evaluation process for the competitive resource solicitation-Phase II.

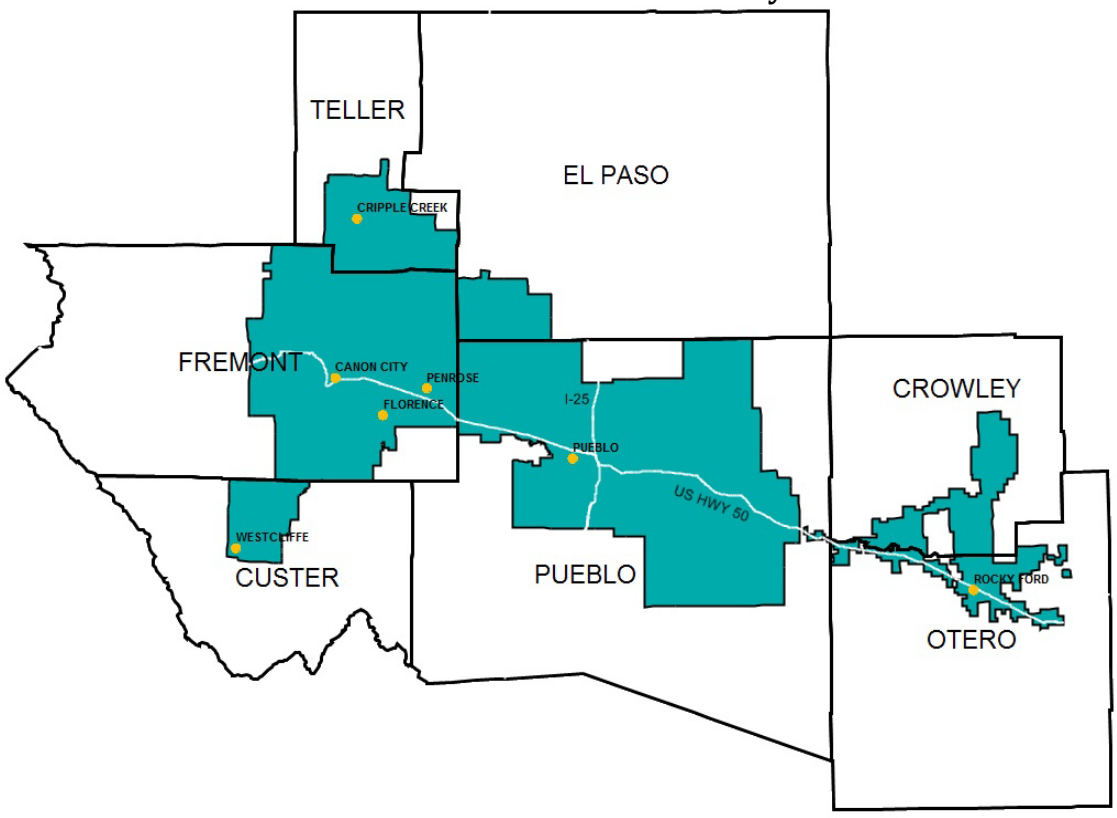
Phase II involves updating modeling inputs and assumptions consistent with the Commission's decision, and the Company's issuance of a request for proposal ("RFP") to govern a competitive solicitation, which is also overseen by an Independent Evaluator. Based on the bids received, the Company will develop several potential portfolios, with one preferred portfolio recommendation as part of Black Hills' "120-Day Report" (named for the amount of time given to the Company to assess the bids after the RFP concludes). The Phase II process permits comments on the Company's 120-Day Report, and it concludes with a Commission decision on the specific

resources the Company is to acquire. The experience from the Company's 2022 CEP proceeding highlights the importance of adhering to the timeframes established in the RFP and Commission rules.

1.1 Background – Black Hills

Black Hills provides electric service to approximately 102,000 customers in 24 communities across Southern Colorado. In 2025, the Company sold more than 1,754 GWh to retail customers. In July 2019, the Company's system peak was set at 422 MW, the highest load level recorded by the Company to date. The Company nearly surpassed that peak with 421 MW in July 2026. The largest communities served include Pueblo, Cañon City, and Rocky Ford. The Company's generating stations are located in Pueblo, Walsenburg and Rocky Ford. The Company's service territory, which encompasses parts of Crowley, Custer, El Paso, Fremont, Otero, Pueblo, and Teller counties, is shown in Figure 1-1 below.

Figure 1-1
Black Hills Service Territory



The Company currently meets its customers' electric demand and energy needs using a mix of Company-owned generation resources, purchased power agreements ("PPA"), and purchases from the market as needed. The Company's generation portfolio includes:

- Pueblo Airport Generating Station ("PAGS"), which consists of natural gas-fired generating units with a total capacity of 420 MW, including:
  - 200 MW of combined-cycle turbines through a PPA with Black Hills Colorado Independent Power Producer ("IPP"), which expires at the end of 2031; and
  - 220 MW of utility owned simple-cycle generation.
- Two diesel stations with a total net capacity of 20 MW, including:
  - Rocky Ford diesel units, located in Rocky Ford, with 10 MW of net capacity; and
  - Airport diesel units, located in Pueblo, with 10 MW of net capacity.
- The Busch Ranch Wind Project[2] in Huerfano County, a 29 MW wind resource which began commercial operation in 2012;
- The Busch Ranch II Wind Project[3] in Huerfano County, a 60 MW wind resource which began commercial operation in 2019;
- The Peak View Wind Project, a 60 MW wind resource located in Huerfano County and Las Animas County, which began commercial operation in 2016
- Two planned resources resulting from the 2022 ERP, including:
  - A 200 MW solar resource PPA which is expected to enter commercial operation in 2029; and
  - A 50 MW utility-owned battery storage project located in Pueblo County, which is expected to enter commercial operation in 2027.

The Company's power delivery system consists of approximately 655 miles of transmission and sub-transmission lines and 3,229 miles of distribution lines.

1.2 Overview of the 2022 ERP/CEP

The Company last filed an ERP, combined with its Renewable Energy Standard ("RES") Plan and Clean Energy Plan, with the Colorado Public Utilities Commission on May 27, 2022.[4] The Company's Preferred Plan included approximately 450 MW of renewable and energy storage resources by 2030 to comply with the State's CEP set forth in §40-2-124, C.R.S. *et seq*.

[2] The Company owns half of the 29 MW and purchases the energy produced by the remaining turbines under a PPA that has a 25-year term.
[3] The Company purchases the energy produced by the 60 MW turbines under a PPA that has a 25-year term.
[4] Proceeding No. 22A-0230E.

The Colorado Public Utilities Commission issued Decision No. C23-0193 in March of 2023, largely approving the Unanimous Comprehensive Settlement Agreement approving the Company's 2022 Phase I ERP and its 2023 through 2026 RES Plan. Further, the decision acknowledged that the Company would structure its Phase II ERP process in such a manner as to allow the Commission to approve both the Company's CEP and ERP following a Phase II solicitation process.

Following the Phase I decision, the Company conducted a Phase II solicitation process. It performed in-depth analysis to create a portfolio of generation projects to best serve customers while also achieving emission reduction requirements to comply with CEP targets. The Company filed a 120-day report detailing the analysis conducted and put forward a preferred portfolio of projects. Commission Decision No. C24-0634 (issued September 4, 2024) directed the Company to move forward with a portfolio of projects consisting of 300 MW of solar and 50 MW of battery storage.[5]

On June 12, 2025, Black Hills filed an application for Certificate of Public Convenience and Necessity ("CPCN") to construct and own a 50 MW battery storage facility.[6] The Commission issued Recommended Decision No. R25-0789 approving the unanimous comprehensive settlement agreement, authorizing the Company to construct and own the 50 MW battery storage facility. The Company anticipates placing the battery into service in 2027.

Regarding the solar projects, the Company filed a motion seeking guidance on whether to proceed with a 100 MW Build Transfer solar project and a 200 MW solar project under a PPA in light of developer price changes. In response, the Commission issued Decision No. C25-0805 on November 12, 2025, directing the Company to move forward with pursuing only the 200 MW solar PPA. The Company currently expects the PPA project to be placed into service in 2029.

Following the filing of its motion, the Company made a supplemental filing presenting the estimated emissions reductions and capacity deficits that could arise depending upon which solar resource was selected.[7] The analysis showed that selecting only the 200 MW solar PPA and declining to accept the 100 MW solar Build Transfer would result in an estimated 79% reduction in emissions by 2030. The analysis also showed the Company would have the following estimated capacity shortfalls and surpluses from 2026 through 2030, as shown in Table 1-1, which did not include meeting

[5] As amended by Decision No. C24-0715-I following the Company's filing for Rehearing, Re-argument, or Reconsideration ("RRR").
[6] Proceeding No. 25A-0255E.
[7] Supplement to Motion of Black Hills Colorado Electric, LLC for Whether to Proceed with 100 MW Solar and 200 MW Solar Clean Energy Projects in Light of Developer Price Changes filed on September 9, 2025, in Proceeding No. 22A-0230E.

industry standard resource adequacy requirements as a part of its settled planning reserve margin:

Table 1-1
BHCOE Capacity Shortfalls and Surpluses (MW)

2026	2027	2028	2029	2030
(76)	(78)	17	6	4

The Company's 2026 Ready to Serve Plan will continue to solve for the previously existing capacity deficits and emissions shortfalls, while adjusting for current conditions including shrinking market availability and regional market impacts. This Plan will address these considerations and will require expedited resource procurement to meet reliability, capacity deficit, and emissions reductions needs.

2.0 Planning Environment

The environment in which utilities must plan their future resources continues to evolve and expand, largely due to ambitious new state and federal environmental policy objectives, but also due to volatility in global energy markets, inflationary conditions, and supply chain constraints. Without addressing all changes to modeling parameters (which are discussed further below), issues and concerns facing the Company during this 2026 ERP planning cycle include:

- Plans and programs for demand-side management;
- Natural gas supply and pricing over the long-term;
- Environmental regulations;
- Colorado's emission-reduction statutes and Renewable Energy Standard;
- Federal production tax incentives for storage projects; and
- Power supply markets in the state and regionally.

Each of these topics is described in turn below.

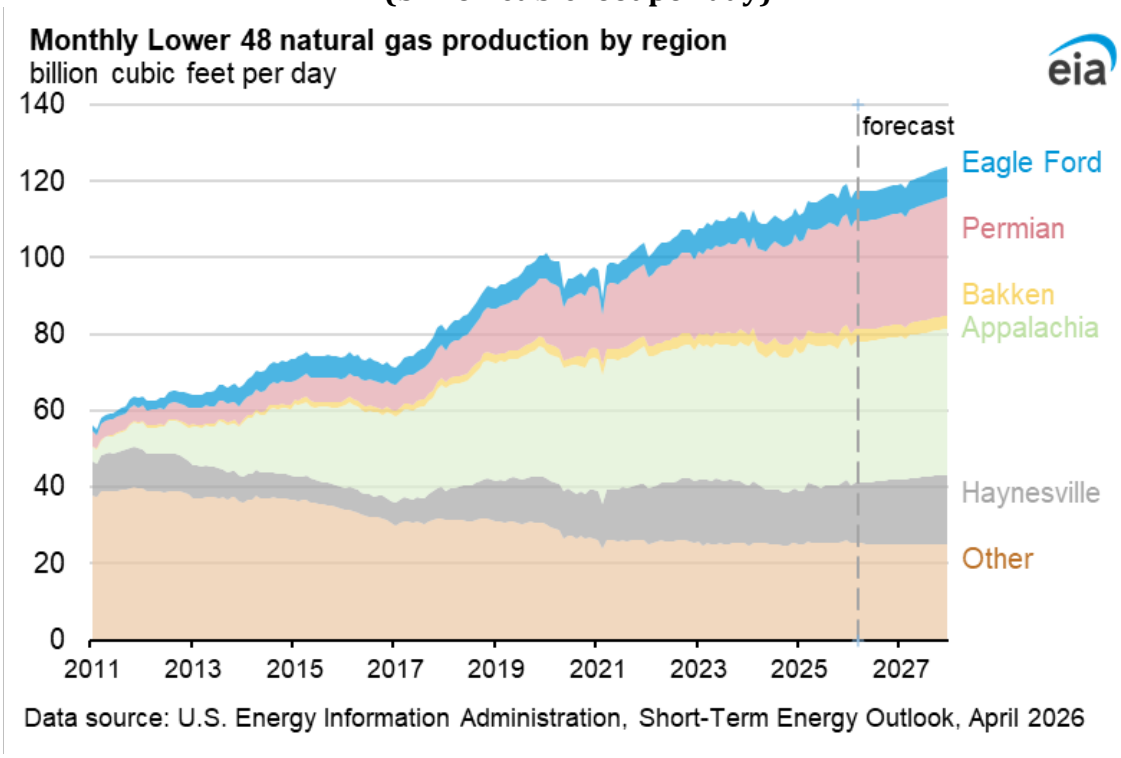
2.1 Demand-Side Management

As a regulated utility, Black Hills is subject to the State's mandatory Demand Side Management ("DSM") provisions (§ 40-3.2-104, C.R.S.), which requires the Company to reduce its retail system peak demand and retail energy sales through implementation of DSM plans. Colorado law defines DSM as one of, or any combination of, the following measures: energy efficiency, conservation, load management, and demand response programs. Under the law, by 2028, Black Hills is to reduce its retail system peak demand (MW) by 5 percent of the 2018 level (408 MW) and reduce its retail energy sales (MWh) by 5 percent of the 2018 level (1,954 GWh). In addition, the Company obtains DSM energy and demand savings consistent with goals approved by the Commission in plans approved every three years. The Company has incorporated demand and energy savings goals from its 2025-2028 DSM plan. In addition, the Company is evaluating additional demand response options as a part of its next DSM filing and will consider their incorporation as a part of its Phase II RFP.

2.2 Natural Gas Supply Trends Over the Long-Term

Shale gas technology continues to be the largest source of U.S. natural gas production. Figure 2-1 below shows the historical and future production forecasts for natural gas.

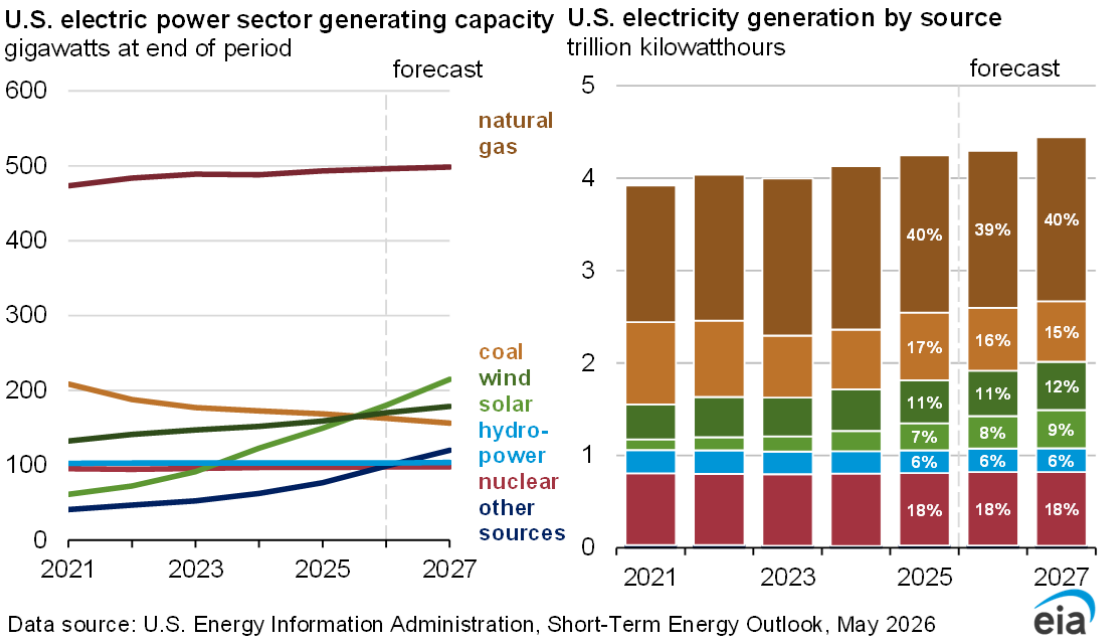
Figure 2-1
U.S. Natural Gas Production, 2011-2027
(billion cubic feet per day)



As a result of environmental regulations promulgated by the U.S. Environmental Protection Agency ("EPA"), including the EPA's Regional Haze Rule, many electric generation owners have retired or converted older, less efficient coal-fired generating facilities to reduce emissions from stationary sources. Renewable generation and natural gas generation have become the lowest-cost resources to comply with these environmental regulations, while offering operational flexibility, large scale capacity, and grid stability. Therefore, most electric generation forecasts reflect continued closure of coal plants, decreasing gas fired generation from the mid-2020s through 2050, and increased renewable energy. Figure 2-2 below illustrates the growth in natural gas electric generation forecasted by the U.S. Department of Energy's Energy Information Administration ("EIA"), published in its May 2026 Short Term Energy Outlook.[8]

[8] https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf

Figure 2-2
EIA's Historic and Projected Electric Generation by Fuel Source



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, May 2026

2.3 Environmental Regulations

The EPA has been active since 2009 regarding regulations for utility-scale power plants, particularly coal-fired power plants. The subsections below provide brief background on some of the key regulations that have impacted the electric sector.

2.3.1 Regional Haze Regulation

During the Phase I and Phase II Regional Haze planning periods, the EPA and states have primarily focused on coal-fired generating facilities due to their significant emissions of haze-forming pollutants, including nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter (PM). Black Hills does not operate coal-fired generation, and its facilities have not been significantly affected by the Regional Haze Rule to date.

Black Hills's natural gas-fired fleet may be subject to increased regulatory scrutiny in future planning periods, as these units emit pollutants that can contribute to regional haze. The State of Colorado may require additional emission control measures to further reduce these impacts. Black Hills' natural gas-fired combustion turbines ("CTs") are already equipped with advanced emissions control technologies, including selective catalytic reduction (SCR) systems to reduce NO_x emissions. As a

result, potential future compliance obligations under Regional Haze regulations are expected to be limited.

2.3.2 Mercury and Air Toxics Regulation

Since the Company does not own coal-fired generation and its oil-fired generation does not trigger applicability thresholds (>25 mw – 40 CFR 63.9981 and 63.10042), it is not affected by the EPA's Mercury and Air Toxics Standard ("MATS"), which was originally finalized on February 16, 2012.

2.3.3 Federal Greenhouse Gas Regulation

Since January 2, 2011, the EPA has been regulating greenhouse gas emissions from the largest stationary sources through the Prevention of Significant Deterioration ("PSD") and Title V Operating Permit Programs. GHGs are comprised of four main gases: carbon dioxide, nitrous oxide, methane, and fluorinated gases like hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, and nitrogen trifluoride.[9] Under the Greenhouse Gas Tailoring Rule, these gases are regulated as pollutants under the major source permitting requirements.

Under the initial rule, new or modified electric generation resources with GHG emissions above 75,000 tons/year must go through a technology-based, source-by-source review process to demonstrate that they will use the Best Available Control Technology ("BACT") to control GHG emissions. This process is required before the resource can receive a Clean Air Act permit.

In June of 2014, the Supreme Court partially upheld a portion of the rule and partially invalidated another portion of the rule. The ruling stated that greenhouse gas emissions could only be reviewed if the source tripped the PSD levels (100 and 250 tons) for criteria air pollutants (PM, SO_2, NO_x, CO, Ozone, and Pb). Sources falling into this category need to conduct a BACT analysis for GHG. The 75,000 tons/year threshold in the Tailoring Rule does not apply.

On October 23, 2015, the EPA finalized GHG New Source Performance Standards for Electrical Generating Units (40 CFR 60.5008-60.5080 aka Quad T). This includes stationary combustion turbines. The applicability date is for generation units that commenced construction after January 8, 2014, and the limit is 1000 CO_2 lb/hour (gross output).

The combustion turbines at the PAGS facility are not subject to the rule as they were permitted prior to the rule's effective date.

[9] https://www.epa.gov/ghgemissions/overview-greenhouse-gases

2.3.4 Environmental Protection Agency's Greenhouse Gas Standards

On April 24, 2024, the EPA finalized emission guidelines for GHG emissions from existing fossil fuel-fired steam generating electric generating units ("EGUs") and finalized revisions to the New Source Performance Standards for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. Emissions limits for CO_2 were established using the EPA's determination of the best system of emissions reduction for GHGs. Subsequently, on June 17, 2025, the EPA proposed to repeal all GHG emissions standards for fossil fuel-fired EGUs, including the CO_2 emissions limits for combustion turbines. The final rule was submitted to the Office of Management and Budget on May 14, 2026, and is anticipated to repeal the fossil fuel-fired EGU GHG emissions standards as originally proposed.

2.3.5 Colorado's Emission Reduction Statutes

In the 2019 legislative session, Colorado passed House Bill ("HB") 19-1261 and Senate Bill ("SB") 19-236. These bills address emission reductions, with HB 19-1261 addressing emission reduction across all sectors of the economy, and SB 19-236 concerning electric utility-specific emission reductions through CEP filings. Subsequent legislation, including SB 23-016, has expanded and strengthened these targets by adding interim milestones and establishing a net-zero GHG emissions goal by 2050.

Summaries of these statutes are provided in the following:

- HB 19-1261: This statute includes targets of reducing statewide GHG pollution 26% by 2025, 50% by 2030, and 90% by 2050, over a 2005 baseline. The statute also supports the development of voluntary Clean Energy Plans that as filed will achieve at least an eighty percent (80%) reduction in greenhouse gas emissions caused by a utility's Colorado retail electricity sales. For utilities that submit a CEP, the Air Quality Control Commission shall not mandate more reductions than is required under such a plan or impose any direct, non-administrative costs on the public utility if the division has verified that the approved CEP will achieve at least a 75% GHG reduction (known as the "Safe Harbor" provision).

- SB 19-236: This statute sets clean energy targets for qualifying utilities to achieve an 80% reduction in carbon dioxide emissions by 2030 from 2005 levels for electricity sales and sets a goal to achieve 100% clean energy resources by 2050 or earlier, if feasible. The statute also includes requirements to govern the resource planning process to achieve those targets, including on the resource acquisition period, cost recovery, and provisions governing retirement of existing facilities.

- SB 23-016: This statute updated Colorado's statewide GHG reduction goals by adding interim targets of 65% by 2035, 75% by 2040, and 90% by 2045, and increased the 2050 target from a 90% reduction to 100% reduction GHG emissions by 2050, all relative to 2005 levels. The legislation also expanded state efforts to support decarbonization through transmission planning, electrification, clean heat initiatives, and other cross-sector emission reduction measures.

2.3.6 Clean Energy Plan Guidance

The Air Pollution Control Division, within the Colorado Department of Public Health and Environment ("CDPHE"), developed a Clean Energy Plan Guidance ("CEP Guidance") document to govern assessment and verification that a utility's CEP achieves the requirements as defined in both HB 19-1261 and SB 19-236.[10] The CEP Guidance includes a verification workbook in the form of a spreadsheet tool to assist verification that a utility's resource plan will achieve the statutory emission reduction targets. The Company is providing with its Plan the verification workbook to promote successful verification. The Company's Preferred Plan achieves an 80% reduction in GHG emissions from 2005 levels based on retail sales. Black Hills has completed verification workbooks for all ERP modeling runs in Appendix L.

2.3.7 Social Cost of Emissions

As required by Section 40-3.2-106, C.R.S., the Company is including within its Plan the social costs of both carbon and methane. These social costs impact resource optimization and net present values. In addition to the Company's Base ERP, several other scenarios include the social cost of emissions. To facilitate consideration of the impacts of these social costs, the Company is also providing scenarios that exclude the social costs, including the Preferred Plan. These scenarios illustrate the range of potential outcomes associated with incorporating such externalities into the optimization of the Company's generation portfolio.

2.4 Colorado Renewable Energy Standard

Section 40-2-124, C.R.S. and the Commission's RES rules require the Company to provide specific percentages of renewable energy and/or recycled energy according to the following schedule: 30% of its retail electricity sales in Colorado for the year 2020 and for each year thereafter.

[10] https://cdphe.colorado.gov/air-pollution/climate-change#Energy.

HB 26-1326 allows the Company to provide the Commission with notice that it is opting out of the RES requirements. However, Black Hills must still have a certain percentage of its retail sales produced by either wholesale distributed generation ("DG") or retail DG, regardless of technology type, according to the following schedule: 3% of its retail electricity sales in year 2020 and each following year. At least one-half of the DG requirement must be generated by retail DG systems located at customers' facilities or premises.

Concurrent with this 2026 ERP, the Company is filing its 2027 through 2030 RES Compliance Plan. The CEP and RES plans are closely aligned and complement each other. The Company's RES Plan demonstrates compliance with the requirements set forth in § 40-2-124, C.R.S.

2.5 Federal Tax Incentives for Wind, Solar, and Storage Projects

The One Big Beautiful Bill Act of 2025, Pub. L. No. 119-21 ("OB3"), modified certain tax incentives for wind, solar, storage and carbon capture projects that were enacted or extended under the Inflation Reduction Act of 2022, Pub. L. No. 117-169 ("IRA"). Specifically, the OB3 repealed the production tax credit ("PTC") and investment tax credit ("ITC") for wind and solar projects that either begin construction after July 4, 2026 or are placed in service after 2027.[11] Previously under the IRA, wind and solar projects were eligible for full value of PTCs or ITCs, if construction began before 2033.

Clean energy electric generation, except for wind and solar, remain eligible for the full value of PTCs and ITCs if construction begins before 2034. Energy storage projects remain eligible for the full value of ITCs if construction begins before 2034. The election out of the normalization rules for energy storage ITCs remains in effect, which allows the benefits to be passed to customers over any period a state commission deems appropriate.

The prevailing wage and apprenticeship rules that were enacted by the IRA still apply to PTCs and ITCs.

The OB3 enacted new rules around Foreign Entities of Concern, which include China, Russia, Iran, and North Korea. For the clean energy electric generation projects and energy storage projects, no credit is allowed for taxable years beginning after enactment if the taxpayer is a Prohibited Foreign Entity ("PFE") and no credit is allowed for a facility that commences construction after December 31, 2025 that includes any material assistance from a PFE. The material assistance from a PFE includes a cost ratio test. Credit eligibility is based on meeting a threshold percentage of non-PFE to total cost that increases by year.

[11] Wind and Solar Projects that begin construction after July 4, 2026 must be placed in service by December 31, 2027.

As more variable renewable generation penetrates the power grid, the ability to integrate those resources becomes more important. As described in Chapter 5, battery storage may be a valuable resource addition. The declining cost of commercially available energy storage technologies leveraging lithium-technology, combined with additional savings due to ITCs, has been met with an increasing interest across the electric utility industry for proposals deploying battery storage.

2.6 The Power Supply Market

Power market transactions yield two main economic efficiencies. They assure that resources with the lowest operating cost serve demand in a region and provide reliability benefits that arise from a larger portfolio of resources. The availability and price of power through the economy energy market is an important factor in how Black Hills operates and plans generation requirements. At times, the utility can purchase less expensive energy through market purchases to serve short-term customer needs, rather than generate energy from utility-owned or contracted generation. Such purchases reduce costs and result in customer benefits. In order to have access to lower cost economy energy, however, the utility must have capacity in place to serve as a backstop for economy energy purchases. In addition, it is increasingly important during times of high market volatility, like extreme weather events, to maintain adequate capacity to support load requirements.

When additional load is anticipated, the Company's Generation Dispatch and Power Marketing ("GDPM") group compares the price of energy on the economy energy market with that of starting up a generating unit. When the economy energy market price is less expensive, GDPM purchases it to satisfy demand; otherwise, they start up the generating unit. GDPM considers unit start-up costs, variable operation and maintenance expenses, ramp rates, and heat rates in these evaluations.

Electric prices in the Western Electricity Coordinating Council ("WECC") region have been low in the current year. This is due to mild weather through winter allowing natural gas storage across the western interconnect to obtain above average storage balances. Prior to this, gas storage was significantly below average causing high natural gas prices and energy prices.

Weather, overall economic conditions, and resource supply availability—all of which can change quickly—drive demand uncertainties in the electricity markets. North American Reliability Corporation's ("NERC") 2025 Long-Term Reliability Assessment ("LTRA")[12] includes over 41,000 circuit miles of planned transmission over the next ten years, as well as many planned additions of natural gas, storage, wind, and solar resources. However, the LTRA, in concert with reports from other industry

[12] https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf

stakeholders, continue to identify lagging generation development as supply chain constraints and rising costs for grid upgrades cause project delays and cancellations. Transmission development is likewise behind where it needs to be to maintain reliability into the future, despite performance improvements.[13] As such, WECC-Rocky Mountain has anticipated adequate capacity through 2033 and will require additional resources beginning in 2034 to meet rapid forecasted demand. The NERC LTRA forecasts capacity deficits in the WECC-Rocky Mountain region starting in the summer of 2034, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period. This regional capacity shortfall, if not addressed, will provide additional downward pressure, potentially shrinking market availability further.

Colorado SB 21-072 requires certain transmission utilities to join an organized wholesale market by January 1, 2030 or seek a waiver of the requirement, subject to specified conditions and exceptions. In furtherance of this requirement, Black Hills announced on January 25, 2022, its plans to join the Southwest Power Pool's Western Energy Imbalance Service ("WEIS") and began participation in April 2023. Participation in the WEIS provided operational efficiencies, supported renewable resource integration, and helped reduce energy costs. Effective April 1, 2026, the WEIS was discontinued as part of Southwest Power Pool's ("SPP") expansion of Regional Transmission Organization ("RTO") operations into the Western Interconnection.[14]

As part of its continuing efforts to comply with the requirement to join an Organized Wholesale Market ("OWM"), the Company filed and received approval to initiate the actions necessary to join Markets+ on December 30, 2025 in Proceeding No. 25A-0548E and has committed to evaluating future market participation options. To support that evaluation, the Company retained The Brattle Group to perform an independent assessment of participation in both SPP Markets+ and the SPP RTO. The results of that analysis are presented in Appendix O. At the time the analysis was performed, the Markets+ evaluation relied on resource adequacy assumptions applicable to the SWEDE WRAP Subregion, including planning reserve margins, accreditation methodologies, and other publicly available metrics. Subsequently, on May 21, 2026, the Western Power Pool ("WPP") announced the establishment of the Rockies WRAP Subregion, replacing the previously anticipated SWEDE footprint for Colorado participants. The creation of the Rockies Subregion introduced uncertainty regarding future planning reserve margins, accreditation metrics, participant composition, and other resource adequacy requirements that were not reflected in the assumptions utilized in the Brattle analysis. WPP currently anticipates Rockies-specific resource adequacy metrics for the initial binding Forward Showing seasons will become available in 2027.

[13] https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_overview.pdf
[14] https://www.spp.org/western-services/weis/ and https://kilowattlogic.com/news/spp-rto-west-launches-april-2026-dual-interconnection

Similarly, resource adequacy requirements within the SPP RTO continue to evolve as stakeholders assess operating experience within the expanded western footprint and evaluate potential changes to planning reserve margin methodologies and accreditation assumptions. As a result, key market design elements continue to develop across both market pathways.

As these market and resource adequacy frameworks continue to evolve, the Company may notify the Commission outlining any impacts to its market participation decision as well as other relevant planning considerations. The Company's ultimate market participation decision, together with future developments in resource adequacy frameworks, may alter the Company's load and resource outlook.[15] Black Hills continues to monitor developments in western regional market structures, including evolving organized market opportunities, and will evaluate their implications for resource adequacy, reliability, customer costs, and long-term resource planning.

[15] Additionally, Section 6.7 discusses the uncertainty of these resource adequacy impacts.

3.0 Clean Energy Plan Key Modeling Assumptions and Inputs

Many data assumptions and inputs are required to complete the load forecast and modeling for the Plan. Among others, assumptions must be made for the Planning Period, Resource Acquisition Period, planning reserves, financial parameters, and DSM impact. In addition, fuel price forecasts, market price forecasts, and emissions cost assumptions must be input into the model for all types of generic resources as well as for existing resources. Selected assumptions are also varied in the scenarios, such as the price of natural gas or load growth, to test the risks associated with specific inputs. Black Hills' key assumptions and inputs are discussed below.

For this Plan, the Company is using resource planning models developed with the assistance of a third-party consulting firm, Energy & Environmental Economics. Specifically, Black Hills retained E3 to complete the modeling work necessary for the Plan, including use of the PLEXOS resource planning models. Benefits of the modeling software used by E3 include optimizing investment and operational decisions while capturing policy requirements related to emissions reductions. E3 is well suited for the modeling undertaking represented by the Plan, given its experience in multiple integrated resource planning efforts for other utilities, as well as assistance with Colorado emission reduction policy frameworks.

3.1 Planning Period

The Commission's ERP Rules allow utilities to select a planning period of between 20 years and 40 years. The Company selected 25 years for this Plan, which covers the period 2026 through 2050. Twenty-five years was selected consistent with the requirements of SB 19-236 and also because it allows an adequate horizon to evaluate conventional and renewable alternatives relative to the useful lives of those alternatives.

3.1.1 Resource Acquisition Period

The RAP covers the timeframe of 2026-2032. Commission Rule 3602(n) defines the RAP to mean the first six to ten years of the planning period. The selected RAP provides adequate time for the acquisition of the necessary resources to meet our customers' resource needs, including the years in which the ERP identified additional resources to meet the Company's capacity needs. The seven-year[16] RAP includes the expiration of the PAGS PPA (end of 2031) to ensure that any identification of additional resources takes this expiration into consideration in the selection of the preferred portfolio. For its capacity expansion modeling, the Company selected 2029

[16] The modeling conducted for this ERP and CEP Plan included planning for the year 2026, which is included in this RAP period and reflected in all present value revenue requirements. The Company recognizes that at the time of filing, a majority of 2026 has occurred and 2027 will be the first full year of planning as the proceeding continues.

as the earliest a new resource could come online. During the Phase II competitive acquisition process the Company expects developers to bid projects with Commercial Operation Dates ("COD") prior to January 1, 2032.

3.2 Planning Reserve Margin

Reliability means securing capacity equal to the forecasted demand plus an additional percentage reserve margin to meet daily peak demand. The reserve margin is based on thermal capacity, capacity factors of renewable resources, and a rigorous analysis of system characteristics. The system characteristics include load shape, the number and size of the generating units, and transmission interties, and outage restoration procedures. The reserve margin must also cover capacity needs in the event of extreme weather, or other unexpected conditions.

A study completed by E3 used industry standard metrics including Loss of Load Probability ("LOLP") modeling to identify a PRM requirement that represents the total capacity needed to maintain a Loss of Load Expectation ("LOLE") standard of 0.1 days per year. The study identified a seasonal 8.5 percent summer and 18.5 percent winter Perfect Capacity ("PCAP") PRM as being sufficient to meet reliability requirements. These reserve margins are equivalent to 27 percent summer and 54 percent winter of Installed Capacity ("ICAP") PRM accounting. The PCAP accounting method is discussed in more detail in Section 6 as well as Highly Confidential Appendix F.

These seasonal reserve margins were used for each of the base, high, low, and increased electrification load forecasts. The Company will acquire, through the Phase II process, generation resources necessary to achieve, at a minimum, the reserve margin throughout the RAP.

Historically, most utilities used ICAP-based PRM accounting methods, which often credits full installed capacity for thermal resources, while renewable and storage capacities may be discounted by an Effective Load Carrying Capacity ("ELCC") rate. The emergence of alternative methods in PRM analysis now include options to provide alignment with all resource accreditation, which is done with the PCAP methodology. This allows for a level playing field in least-cost portfolio comparison among all resource options.

Neighboring organized markets and leading industry reports calibrate reliability using standard metrics such as LOLE, Loss of Load Hours ("LOLH"), and Expected Unserved Energy ("EUE"), regardless of the Planning Reserve Margin ("PRM") or Effective Load Carrying Capacity methodologies applied. In response to increasing renewable penetration, evolving load shapes, and greater participation in organized markets, Black Hills has transitioned from an annual Installed Capacity framework to a seasonal PCAP approach to better capture reliability uncertainty. Consistent with

this trend, Midcontinent Independent System Operator ("MISO")[17] and SPP[18] also employ seasonal PRMs due to technology-specific reliability differences. Industry benchmarks reflect a wide range of PRM outcomes, including Total Reliability PRMs of 36.5 percent in 2028 to 49.2 percent in 2034 in the 2025 WARA PRMA[19] and PRMs ranging from 30.5 percent in 2023 to 6.9 percent in 2035 in the 2025 NERC LTRA.[20] Black Hills continues to monitor industry developments, including energy assurance and computational load risks, while evaluating methodologies best suited to its system.

As variability across the region increases, it is important to have units capable of responding to unplanned events. Gas units offer capabilities to respond to variability in available energy. Energy storage resources can provide regulation frequency response benefits through quick dispatch ability and frequency control, resulting in improved grid stability.

3.3 Fuel and Market Prices

The fuel price assumptions used in the Plan were based on a 25-year Electricity Price Forecast created by Energy Strategies in 2025. The details of the fuel price forecasts are set forth in Appendix H.

3.3.1 Natural Gas Prices

Natural gas price forecasts were derived by Energy Strategies, who developed reference (base), low gas, and high gas sensitivities that are based upon EIA AEO 2025 Reference information. These forecasts include basis transport costs and were adjusted based upon EIA's STEP and NYMEX near term future curves. To determine the burner-tip cost to the Pueblo region, the Energy Strategies' Henry Hub forecast was used, plus a basis differential, in addition to pipeline and transportation costs.

The Company used the natural gas price for both existing and future natural gas-fired resources. Table 3-1 lists the price ranges for Energy Strategies' Henry Hub natural gas prices from the beginning and ending years of the planning period as well as 2030, when emissions reduction targets must be met, for the natural gas scenarios. The scenario forecasts are also listed in Schedules H-1, H-2, and H-3, Appendix H.

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[17]https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2003%20PY%202025-2026%20LOLE%20Study%20Results654956.pdf
[18]https://www.spp.org/documents/76399/2025%20lole%20study%20prm%20recommendation.pdf
[19]https://www.wecc.org/sites/default/files/documents/products/2025/2024%20PRM%20Analysis.pdf
[20] *Id.* See Page 34.

Table 3-1
Average Annual Henry Hub Gas Price ($2024/MMBtu)

Scenario	Henry Hub		
	2026	2030	2050
Base Gas	$3.72	$3.08	$4.81
High Gas	$4.08	$5.91	$9.76
Low Gas	$2.11	$2.32	$2.83

3.3.2 Oil Prices

Energy Strategies developed a base diesel (DFO #2) price forecast based upon EIA AEO 2025 Reference information. Table 3-2 below shows the average oil prices for years 2026, 2030 and 2050, and more detail is provided in Schedule H-4, Appendix H.

Table 3-2
Average Annual Oil Price ($2024/MMBtu)

No. 2 (Distillate) Price			
Scenario	2026	2030	2050
Base Diesel	$23.38	$22.16	$25.74

3.3.3 Clean Fuel Prices

The clean fuel price forecasts were developed by Black & Veatch for various scenarios. Nuclear fuel prices were developed using internal Black & Veatch data. Renewable natural gas ("RNG") pricing used a combination of publicly available and in-house information. RNG was selected as the clean fuel proxy for CTs to meet constraints in the CEP scenarios.[21] The clean fuel price forecasts are shown in Table 3-3, and they are further available in Schedule H-5, Appendix H.

[21] RNG and CEP scenarios are described further in Sections 5.4.1.1 and 8.6.

Table 3-3
Average Annual Clean Fuel Price (Nominal $/MMBtu)

Scenario	Nominal Clean Fuel Price		
	2026	2030	2050
RNG	$27.73	$30.00	$44.61
AP3000 Nuclear Fuel	$1.02	$1.09	$1.68
Gen IV Nuclear Fuel	$2.93	$3.14	$4.83

3.3.4 Economy Energy Prices

Electric energy price forecasts were derived by Energy Strategies, who uses proprietary databases and PLEXOS modeling software to develop zonal energy price forecasts. These forecasts represent a reasonably anticipated regional view of developments for the long-term planning horizon. Their modeling efforts incorporate known and projected system energy, capacity, and policy needs at least-cost solutions. To determine the expected regional energy market cost, the Energy Strategies' forecasts for Palo Verde ("AZ-PV") and Mid-Columbia ("Mid-C") market area price were used. The two area forecasts are blended together to get an AZ-PV/Mid-C average price. Energy Strategies used EIA information to calculate their Low Gas and High Gas sensitivities.

Table 3-4 below shows the price ranges from the beginning and ending years of the Planning Period as well as 2030, when emissions reduction targets must be met, for the Base ERP Plan and scenarios completed for the Plan. The market area price forecasts are also included in Schedules H-6, H-7, and H-8, Appendix H.

Economy energy is energy (sold without capacity) that may be available in the market from time-to-time and which is available at prices that are lower than the incremental cost of a utility's own resources. Economy energy is not firm energy and, therefore, it is only available if a utility has adequate capacity to support its load requirements. The selling party may recall an economy energy transaction at any time. Thus, the buying party must maintain sufficient contingency reserve to replace recalled supply. The model was allowed to purchase up to 100 MW of economy energy every hour.

Table 3-4
Average Annual On-Peak & Off-Peak AZ-PV/Mid-C Price Forecasts

Scenario	AZ-PV/Mid-C Blend		
	2026 Price ($/MWh)	2030 Price ($/MWh)	2050 Price ($/MWh)
Base Natural Gas	$31.33	$24.63	$18.41
High Natural Gas	$33.48	$37.22	$31.27
Low Natural Gas	$22.77	$21.08	$13.15

3.4 Financial Parameters

Financial assumptions were used to develop incremental financial statements for the Company. Cost of debt and equity, return on rate base, and interest rate assumptions are necessary for the model to calculate the total system PVRR.

Table 3-5 presents the financial parameters used for the Plan evaluation, including cost of debt, cost of equity, weighted-average cost of capital, income tax rate, rate of escalation (same as inflation rate), capital structure, property tax rate, and fixed charge rates. 20-year tax life were used for baseload gas resources, 15-year tax life for peaking gas resources and small modular reactors, and a 5-year tax life was used for solar, wind, and battery storage. Fixed charge rates represent resources built in 2030.

The Company's cost of debt, return on equity, capital structure, and weighted-average cost of capital were approved by the Commission in the Company's most recent electric rate case (Proceeding No. 24AL-0275E). On June 12, 2026, the Company filed a rate case (Proceeding No. 26AL-0232E), and due to the timing of the filing, these values were awaiting Commission review and approval and therefore not used in the Plan evaluation but will be updated in the Phase II modeling.

Table 3-5
Financial Parameters

Component	Annual Rate (percent)
Cost of Debt	4.61
Equity	9.50
Weighted-Average Cost of Capital ("WACC" After-tax[22])	6.31
Income Tax Rate	24.48
Rate of Escalation[23]	2.31
Capital Structure	
Equity Debt	47 53
Property Tax Rate	0.883
Solar 2030 fixed charge rate (25-year)	8.06
Wind 2030 fixed charge rate (25-year)	8.06
Storage 2030 fixed charge rate (20-year)	9.13
Baseload Gas 2030 fixed charge rate (35-year)	9.02
Peaking Gas 2030 fixed charge rate (35-year)	8.78
Nuclear SMR 2030 fixed charge rate (35-year)	7.54

3.5 Social Cost of Emissions

The social cost of carbon and social cost of methane were considered in the Base ERP, Clean Energy Plan, and many of the scenarios. For comparative purposes, the SCC and SCM were also removed from alternative scenarios. The SCC and SCM were applied to owned generation assets, purchased contracts, and market transactions. Section 8.6 provides a detailed description of which scenarios include these emissions costs. The specific values used for the social costs of emissions is provided in Table 3-6, and these are from the Interagency Working Group's ("IWG") Technical Support Document ("TSD").[24]

[22] The after-tax cost of capital is based on the after-tax cost of capital approved in the most recent rate review.
[23] The rate of escalation used in this study may be low, given current inflationary pressures the Company is experiencing, the Company reserves the right to update as necessary.
[24] Section 40-3.2-106(4), C.R.S., specifies what level to use for SCC by incorporating the levels from the IWG TSD using at most a 2.5% discount rate, beginning with not less than $68 per short ton in 2020. Section 40-3.2-106 is silent on what value to use for SCM. Black Hills used SCM values consistent with those in the IWG TSD.

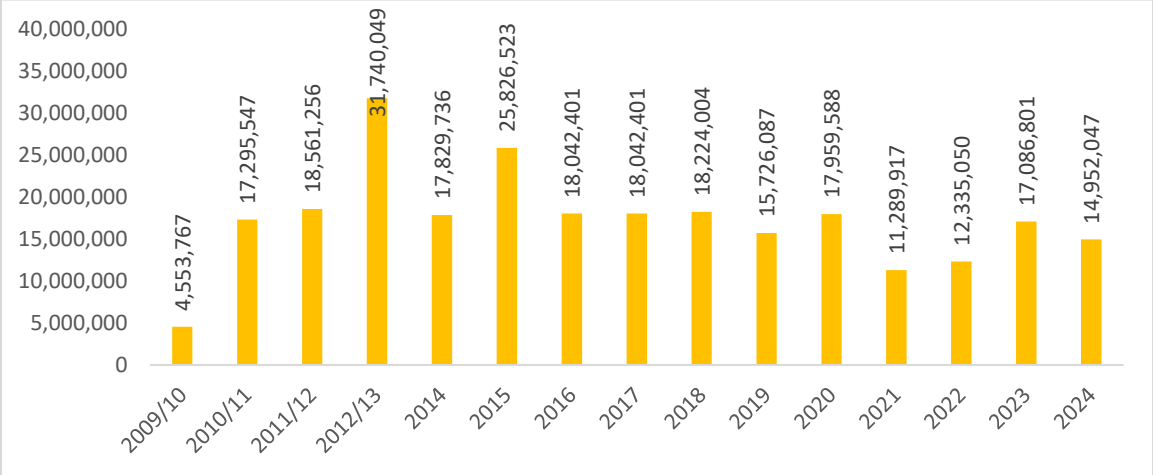
Table 3-6
Annual Social Cost of Carbon and Methane Price ($/Short Ton)

Year	SCC	SCM
2026	$77.99	$1,968
2027	$79.79	$2,014
2028	$81.63	$2,060
2029	$83.52	$2,108
2030	$85.45	$2,157
2031	$87.42	$2,207
2032	$89.44	$2,257
2033	$91.50	$2,310
2034	$93.62	$2,363
2035	$95.78	$2,418
2036	$97.99	$2,473
2037	$100.26	$2,531
2038	$102.57	$2,589
2039	$104.94	$2,649
2040	$107.37	$2,710
2041	$109.85	$2,773
2042	$112.38	$2,837
2043	$114.98	$2,902
2044	$117.64	$2,969
2045	$120.35	$3,038
2046	$123.13	$3,108
2047	$125.98	$3,180
2048	$128.89	$3,253
2049	$131.87	$3,328
2050	$134.91	$3,405

3.6 Demand-Side Management

DSM plans for the Company are filed for and approved outside of the ERP process. Black Hills has administered DSM plans since 2009 helping customers to conserve energy and save money. Figure 3-1 below shows the energy efficiency savings that were achieved from 2009 through 2024.

Figure 3-1
2009 – 2024 Energy Efficiency Savings (kWh)



Black Hills filed for approval of its 2025-2028 Electric DSM Plan for calendar years 2025, 2026, 2027 and 2028 on April 1, 2024 in Proceeding No. 24A-0157E. A full settlement was reached and filed on September 20, 2024. The hearing was vacated and Recommended Decision No. R24-0787 (mailed Oct. 29, 2024) accepted the settlement. Black Hills made a compliance filing on December 20, 2024 to implement the approved plan, containing average energy savings goals of approximately 16.9 GWh per year and an annual average demand (kW) savings goal of approximately 4,260 kW.

The load forecast developed for this proceeding was reduced by the projected savings filed in the Company's direct case in its 2025-2028 DSM Plan shown in Table 3-7.

Table 3-7
DSM Assumptions Used

DSM Plan Year	Projected Peak Savings at the Meter (MW)	Projected Energy Savings at the Meter (MWh)
Plan Year 1 - 2025	4.28	16,910
Plan Year 2 - 2026	4.22	16,915
Plan Year 3 - 2027	4.25	16,921
Plan Year 4 - 2028	4.28	16,948

The DSM assumptions are incorporated into the load forecast as explained in Section 4.0. These annual load forecast adjustments to peak demand and energy are shown in Table 3-8.

Table 3-8
Adjustments to Load Forecast for DSM

Year	Projected Peak Savings (MW)*	Projected Energy Savings (MWh)**
2026	6.74	33,826
2027	10.98	50,747
2028	15.25	67,695
2029	17.04	67,695
2030	17.04	67,695
2031	17.04	67,695
2032	17.04	67,695
2033	17.04	67,695
2034	17.04	67,695
2035	17.04	67,695
2036	17.04	67,695
2037	17.04	67,695
2038	17.04	67,695
2039	17.04	67,695
2040	17.04	67,695
2041	17.04	67,695
2042	17.04	67,695
2043	17.04	67,695
2044	17.04	67,695
2045	17.04	67,695
2046	17.04	67,695
2047	17.04	67,695
2048	17.04	67,695
2049	17.04	67,695
2050	17.04	67,695

*Demand adjustment reflects the expected saving achieved as of July 1 of each year.
**Energy adjustment reflects the expected savings achieved over the entire year.

4.0 Load Forecast

The starting point for ERP modeling and analysis is an annual peak and energy load forecast. This forecast, based on realistic assumptions about local population changes and local economic factors, determines the future demand the utility's resources will be required to meet.

The Plan employs an econometric forecasting methodology to forecast peak demand and energy. The Company gathered and refined a variety of different types of datasets, including historical load, economic, and weather data. This data was used to develop models for the monthly peak demand forecast and energy forecasts.

The final net, base, system-level monthly peak demand and energy forecasts were computed in a similar manner. A statistical regression analysis was performed using class-level datasets segmented between customers with Behind-the-Meter ("BTM") renewables on premise and customers without such resources. From there, several other datasets were layered on top, including company-use and lighting sectors, large customer known and anticipated loads, the effects of Commission approve Demand Side Management or Energy Efficiency Plans, and transmission and distribution losses. For modeling purposes, final gross, base, system-level demand and energy forecasts were also computed. This was completed by layering forecasted BTM, Community Solar Garden ("CSG"), and Inclusive Community Solar ("ICS") effects on the net forecast.

The Plan developed base, low, high, and increased electrification load forecasts.

4.1 Econometric Model Overview

Econometric modeling was used as the foundation for the customer level demand and energy forecasts. The econometric models were developed using the statistical software package Stata®. Black Hills used this software to develop statistical models that estimate the effect of various factors (e.g., weather) on class level energy, the number of customers served, and class level coincident peak demand. The explanatory factors used in these equations consist of weather, demographic variables, and economic variables.

The advantages of econometric forecasting models include:

- The ability to estimate effects of specific drivers on sales and demand, controlling for the effect of all other included variables. For example, the models estimate the effect of economic conditions on sales controlling for variations in weather conditions.
- The ability to refine and adapt the models to reflect changing circumstances over time.

- The use of third-party weather, economic, and demographic data in the forecast removes potential concerns about biased inputs.
- Providing measures of the statistical precision of the estimates, such as the statistical significance of particular driver variables or the overall explanatory power of the forecast model.

Econometric forecasting models reveal relationships between energy (or demand or the number of customers served) and economic or demographic variables to forecast future developments. The process begins by estimating the historical relationship between energy (or demand or the number of customers served) and the relevant drivers, which may include weather, economic conditions, demographic trends, or seasonal patterns. The resulting estimates of the relationship between each driver and the associated outcome (e.g., energy) are then applied to forecasts of the drivers to develop the forecast energy, demand, or number of customers served. The statistical models are reviewed and refined to ensure that the estimated relationships are reasonable (i.e., correctly signed and of reasonable magnitude).

4.2 Load, Economic, and Weather Data

As noted above, the Company uses historical load data (including information on large customers), economic data, and weather data as principal inputs into its load modeling. These data inputs are discussed in more detail below.

4.2.1 Historical Load Data

The Plan utilizes historical class level hourly load data to develop the net demand, energy, and customer count forecasts. These datasets were gathered from the historical MDMS database at the meter level and then aggregated to class level based upon rate identification. The major class levels included are Residential, Small General Service, Large General Service, and Large Power Service. The class level definitions were also split into two categories: customer loads with BTM on premise (for example, Residential BTM) and those who don't (for example, Residential Non-BTM).

The Company identified three individual large customers whose loads were removed from the historical load data before modeling. The Company excluded these customers' loads from historical data because the loads are large and not expected to grow at the same rate as the class level regressions. Similarly, historical data for company use and lighting sectors were also removed prior to running the class level regressions. The Company did not want the growth rates calculated through the regression analysis applied to these unique loads. Black Hills subtracted these hourly load datasets from the class level historical data, creating a new historical dataset that became the basis for the regression analysis. It should be noted that the excluded data

was added back into the demand and energy forecasts after the regression analysis was complete.

The historical demand, energy, and customer data used in the system forecasts are included in Schedule B1-2, Schedule B2-2, and Schedule B3-2, Confidential Appendix B, respectively.

4.2.2 Economic Data

Economic and demographic historical and forecast data were obtained from Woods & Poole Economics, Inc. ("W&P") for Pueblo and Fremont Counties for the years 1969 through 2060. Though this dataset includes a variety of economic variables, Black Hills determined that the relevant variables for the Company's load forecasts were persons per household, number of households, real household total personal income, total employment, and gross regional product ("GRP"). Each of these variables was tested in the regression analysis.

The historical and forecasted economic data used in the peak demand and energy models are included in Confidential Schedules B1-2 and B2-1, Confidential Appendix B.

4.2.3 Weather Data

Historical weather data was collected from the National Oceanic and Atmospheric Administration's ("NOAA") National Climatic Data Center's ("NCDC") Pueblo Airport weather station. The historical hourly temperature data was used to calculate heating degree days ("HDD") and cooling degree days ("CDD") using a 60 degree Fahrenheit threshold. The heating degree hours ("HDH") and cooling degree hours ("CDH") were calculated using 50 degree and 70 degree Fahrenheit thresholds, respectively. The HDD, CDD, HDH, and CDH data were used for both historical and normal weather forecasting purposes. The monthly CDD daily average was based upon the monthly average of total CDD; similarly, the monthly HDD daily average was based upon the monthly average of total HDD. Some of the models used solar irradiance data, which can help explain the differences in solar generation. This data was provided by NASA Power for Pueblo, Colorado. The historical weather data used in the peak demand and energy models is included in Schedule B1-3 and Schedule B2-3, Confidential Appendix B, respectively.

4.2.3.1 Normal Weather Conditions

The weather variables in the energy forecast are set to reflect "normal" conditions, which is interpreted as the average weather conditions over 20 years. In this case, the average of the monthly total cooling degree days over the 20-year period was used to calculate normal weather for each month. In the peak demand model, hourly load

data identified peak and near-peak hours that were used to calculate the normal weather conditions for eight historic years. Additionally, the demand forecast each month is categorized as either a predominantly cooling- or heating-peak month, and then only the relevant peak-hours for each month and year are averaged to calculate peak conditions for that month and year. Those monthly averages are then averaged across the available years for use as normalized peak weather conditions. Customer forecasts are not weather normalized because customer counts are not weather sensitive.

4.3 Forecast Methodology

Multiple combinations of the variables described above were tested in the development of the energy and demand forecasts. The models were refined to ensure that the estimates were logically reasonable (e.g., energy increases with CDDs) and statistically significant (or approaching statistical significance). Normal weather conditions are used to forecast energy and demand.

4.3.1 Coincident Peak Demand Forecast Methodology

The Company's system, net, base coincident peak demand forecast is an aggregation of class-level regression analyses, company use and lighting sector information, large customer base load and anticipate growth assumptions, DSM plan effects, and calculated transmission and distribution line losses. This section will discuss the class-level regression analysis.

In order to produce class coincident peak forecasts, peak and near-peak hours were identified at a monthly, system-level. This ensures that every customer class demand forecast has the same coincident peak, and when aggregated together, the sum produces a system-level forecast that does not over- or underestimate the monthly demand.

From there, each major class was split further into two categories, customers with BTM on premise, and those without, based on historical classification of Rate IDs. These sub-datasets were used to produce regression models for Demand per Customer ("DPC") forecasts as well as customer count forecasts for the following: Residential BTM, Residential Non-BTM, Small General Service BTM, Small General Service Non-BTM, Large General Service BTM, Large General Service Non-BTM, Large Power Service BTM, and Large Power Service Non-BTM.

The regression models estimate the peak forecast using hours within three percent of the month's historical peak value. The resulting estimates were used in combination with normal weather and forecasted economic conditions to forecast peak demands.

Additional analysis was performed with information from the National Laboratory of the Rockies ("NLR") to forecast the rate of change in the share of customers that have BTM to those who do not for the Residential and SGS BTM classes.

Next, the demand forecast is calculated by multiplying the DPC by customer count. Each class level forecast represents that class's share of the total peak demand, therefore producing coincident class level demand forecasts.

Summaries of the final equations, historical and forecasted values of variables used, and resulting forecasts for the demand models are provided in Schedules B1-6 through B1-21, Confidential Appendix B.

4.3.2 Energy Forecast Methodology

Similar to the demand forecast methodology, the Company's system, net, base energy forecast is an aggregation of class-level regression analyses, company use and lighting sector information, large customer base load and anticipate growth assumptions, DSM plan effects, and calculated transmission and distribution line losses. This section will discuss the class-level regression analysis.

Each major class was split further into two categories, customers with BTM on premise, and those without, based on historical classification of Rate IDs. These sub-datasets were used to produce regression models for Use per Customer ("UPC") forecasts as well as a customer count forecasts for the following: Residential BTM, Residential Non-BTM, Small General Service BTM, Small General Service Non-BTM, Large General Service BTM, Large General Service Non-BTM, Large Power Service BTM, and Large Power Service Non-BTM.

The regression models estimate the energy forecast based on summing the historical load values. The resulting estimates were used in combination with normal weather and forecasted economic conditions to forecast energy.

Additional analysis was performed with information from the National Laboratory of the Rockies to forecast the rate of change in the share of customers that have BTM to those who do not for the Residential and SGS BTM classes.

Next, an energy forecast is calculated by multiplying the UPC by customer count. Each class level forecast represents that class's share of the total energy.

Summaries of the final equations, historical and forecasted values of variables used, and resulting forecasts for the energy models are provided in Schedules B2-6 through B2-21, Confidential Appendix B.

4.3.3 Large Customer Growth Assumptions

The Company periodically reviews the growth plans of its largest customers in its service territory. These expected load increases can be uncertain and depend to a great extent on economic conditions. Table 4-1 shows anticipated large customer load additions and reductions (with confidence factor applied) for the RAP period 2026 through 2032. This information was compiled based on information gathered by the Company's economic development personnel and adjusted by a confidence factor depending on the level of certainty expressed by the customer that the growth will actually occur. Additionally, estimated load for potential commercial customers from the anticipated impacts of the Economic Development Tarriff are included, which account for load additions greater than 3 MW and up to 40 MW to be incorporated onto the Company's system.[25] These annual changes in large customer loads are reflected in the peak demand and energy load forecasts.

The Company is engaged in discussions with potential customers that may represent large load additions to the system. Should these discussions lead to a commitment, the load additions indicated in Table 4-1 could fall well short of actual load growth through 2032. The reason these potential large loads are not included in Table 4-1 is that the discussions have not progressed to the point of the level of commitment needed for resource planning purposes. See, e.g., Commission Decision No. C25-0747 (issued November 6, 2025) in Public Service Company of Colorado Proceeding No. 24A-0442E ("If large load customers are willing to take such steps and commit to Colorado, the Commission is eager to support Public Service in acquiring new generation. We are unwilling to make existing customers pay for additional generation before such a commitment"). Should such a level of commitment occur for BHCOE, the Company will either supplement the information in this proceeding, file for special contract approval, or some combination of these.

[25] The Company's current Economic Development Rate guidelines can be found in its schedule of rates, rules and regulation for electric service on tariff sheet Nos. 114 through 116. The most recent guidelines were approved by Decision No. C26-0345 in Proceeding No. 25A-0500E.

Table 4-1
Large Customer Load Additions and Reductions 2026 – 2032

Year	Large Customer 1 (MW)	Large Customer 2 (MW)	Large Customer 3 (MW)
2026	-2.3	1.5	0
2027	0	0	0
2028	0	0	20
2029	0	0	0
2030	-1	0	20
2031	0	0	0
2032	0	0	0
Ave Load Factor (%)	81	61	80

4.4 Base Peak Demand and Annual Energy Forecasts

The final, net, base system-level monthly peak demand and energy forecasts were computed by adding the previously excluded large customer load data, company use load data, and lighting load data, as well as anticipated future load growth of selected large customers, the effects of the DSM Plan, and calculated transmission and distribution line losses to the class-level load forecasts calculated by the regression analysis.

The transmission and distribution losses were added into both the demand and energy forecasts. Based on the most recent transmission and distribution line loss study included in Appendices I and J, forecasted losses were calculated for summer and winter demand and summer and winter energy purposes. Additionally, the seasonal losses were estimated by calculating a weighted loss percentage for each aggregated major class. The class level transmission and distribution losses are shown in Table 4-2. The peak demand and energy forecast values for the base load forecast are shown in Table 4-3.

Table 4-2
Transmission and Distribution Losses

Major Class	Line Loss Class	Aggregate Summer Demand	Aggregate Summer Energy	Aggregate Winter Demand	Aggregate Winter Energy
Residential	Residential	4.60%	3.94%	4.11%	3.62%
Commercial	Large General Service - Primary	4.36%	3.75%	3.92%	3.47%
	Large General Service - Secondary				
Commercial	Small General Service	4.60%	3.94%	4.11%	3.62%
Industrial	Large Power Service - Primary	2.76%	2.48%	2.68%	2.49%
	Large Power Service - Secondary				
	Large Power Service - Transmission				
Large Customer 1		1.60%	1.60%	1.80%	1.80%
Large Customer 2		2.14%	2.01%	2.21%	2.12%
Large Customer 3		1.60%	1.60%	1.80%	1.80%
Lighting		4.60%	3.94%	4.11%	3.62%
Company Use		4.60%	3.94%	4.11%	3.62%
Auxiliary		2.86%	2.86%	2.77%	2.77%
Other Large Customers		2.66%	2.41%	2.60%	2.43%
Economic Development		1.60%	1.60%	1.80%	1.80%

Table 4-3
Base Load Forecast

Year	Peak Demand* (MW)	Losses (MW)	Annual Energy* (MWh)	Losses (MWh)
2026	431.5	37.3	1,947,641	154,601
2027	429.6	37.2	1,929,648	153,462
2028	447.9	37.4	2,057,899	155,032
2029	448.2	37.5	2,055,301	154,819
2030	469.5	38.0	2,192,479	156,988
2031	471.5	38.2	2,195,357	157,233
2032	473.4	38.3	2,201,769	157,772
2033	475.0	38.5	2,202,951	157,885
2034	476.4	38.6	2,210,704	158,554
2035	477.8	38.7	2,219,775	159,338
2036	479.2	38.9	2,230,684	160,266
2037	480.6	39.0	2,230,473	160,258
2038	482.0	39.1	2,234,091	160,569
2039	483.3	39.2	2,237,545	160,865
2040	484.5	39.4	2,247,957	161,751
2041	485.8	39.5	2,249,704	161,912
2042	487.0	39.6	2,252,936	162,189
2043	488.3	39.7	2,257,763	162,604
2044	489.6	39.8	2,266,595	163,353
2045	491.0	40.0	2,265,487	163,267
2046	492.4	40.1	2,268,019	163,483
2047	493.9	40.2	2,270,655	163,708
2048	495.4	40.4	2,277,048	164,245
2049	497.1	40.5	2,274,780	164,059
2050	498.9	40.7	2,276,819	164,232

*Peak Demand and Annual Energy Forecast values includes impacts of DSM Plans and losses.

4.5 Low and High Forecasts

The base load forecast is assumed to represent the expected midpoint of possible future outcomes, meaning that a future year's actual load may deviate from the midpoint projections. To evaluate the impact of these potential deviations, low and high load forecasts were developed.

The Company prepared low and high load forecasts in addition to its base load forecast as required by Rule 3606(b). For the high and low load forecasts, the

Company developed an 80 percent confidence interval band around the base demand and energy forecasts, using the economic estimator Gross Regional Product.

The peak demand model provided an estimate of the effect of changes in GRP on changes in peak demand, along with a standard error associated with the estimate. These two uncertainties (in GRP over time and in the estimated effect of GRP on peak demand) are combined to produce the confidence interval around the demand and energy forecasts. The specific steps used to develop the confidence interval are described in Confidential Appendix B.

4.6 Increased Electrification Forecast

The increased electrification forecast was developed by E3 and added to the base load forecast for analysis in the Increased Electrification scenario. Table 4-4 below shows the increased electrification scenario and the detailed breakdown of different load components, including vehicle electrification and building electrification. The electrification loads were taken from projections developed for the state of Colorado in Colorado's Greenhouse Gas Pollution Reduction Roadmap 2.0 and were downscaled based on the Company's share of the statewide load. Building and transportation electrification are expected to drive significant load growth in Colorado Electric's system in the long term in this scenario. The system average annual energy growth rate is expected to be 2.4%. Total system load will reach 3,571 GWh by 2050, almost double the current system load. Additional details for this forecast can be found in E3's Technical Report (Highly Confidential Appendix F).

Table 4-4
Increased Electrification Energy Forecast (MWh)

Year	Residential Building Heating	Commercial Building Heating	LDV Charging	MHDV Charging	Industrial	Total Electrification Load
2026	6,683	4,880	23,135	458	16,771	51,927
2030	32,129	24,112	138,801	2,910	67,905	265,856
2035	58,582	45,337	328,157	5,076	113,578	550,730
2040	85,707	68,171	517,670	6,054	127,766	805,368
2045	119,114	97,104	674,304	5,696	156,274	1,052,492
2050	166,862	139,088	744,663	5,885	191,411	1,247,909

The values for the base, low, and high load forecasts, including the effects of DSM are shown in Table 4-5.

Table 4-5
Low, Base, and High Load Forecasts

Year	Peak Demand (MW)			Annual Energy (MWh)		
	Low	Base	High	Low	Base	High
2026	428.3	431.5	434.8	1,941,936	1,947,641	1,953,276
2027	423.0	429.6	436.3	1,921,074	1,929,648	1,938,097
2028	438.0	447.9	457.9	2,041,996	2,057,899	2,073,690
2029	435.5	448.2	461.1	2,032,982	2,055,301	2,077,918
2030	454.3	469.5	485.2	2,167,050	2,192,479	2,218,268
2031	453.7	471.5	489.9	2,166,281	2,195,357	2,224,899
2032	453.3	473.4	494.3	2,164,631	2,201,769	2,240,274
2033	452.8	475.0	498.2	2,155,971	2,202,951	2,252,503
2034	452.5	476.4	501.6	2,153,919	2,210,704	2,270,548
2035	452.1	477.8	504.9	2,151,531	2,219,775	2,291,755
2036	451.8	479.2	508.3	2,148,812	2,230,684	2,318,746
2037	451.4	480.6	511.7	2,141,050	2,230,473	2,328,199
2038	451.1	482.0	515.0	2,140,117	2,234,091	2,336,857
2039	450.7	483.3	518.2	2,139,229	2,237,545	2,345,142
2040	450.4	484.5	521.3	2,136,729	2,247,957	2,372,021
2041	450.1	485.8	524.4	2,129,523	2,249,704	2,385,607
2042	449.8	487.0	527.4	2,128,704	2,252,936	2,393,490
2043	449.5	488.3	530.6	2,127,478	2,257,763	2,405,221
2044	449.2	489.6	533.9	2,125,488	2,266,595	2,429,634
2045	448.8	491.0	537.3	2,118,736	2,265,487	2,437,723
2046	448.5	492.4	540.9	2,118,106	2,268,019	2,444,033
2047	448.1	493.9	544.6	2,117,450	2,270,655	2,450,611
2048	447.7	495.4	548.6	2,116,145	2,277,048	2,470,195
2049	447.3	497.1	552.9	2,109,809	2,274,780	2,476,124
2050	446.9	498.9	557.4	2,109,182	2,276,819	2,481,471

Table 4-6 shows the total system summer and winter peak demand forecast for each year of the Planning Period.

Table 4-6
Seasonal Peak Demand Load Forecast Comparison – Base, Low, and High (including impacts of DSM Plans)

Year	Peak Summer Demand (MW)			Peak Winter Demand (MW)		
	Low	Base	High	Low	Base	High
2026	428.3	431.5	434.8	312.4	314.7	317.0
2027	423.0	429.6	436.3	308.5	313.2	317.9
2028	438.0	447.9	457.9	323.7	331.0	338.4
2029	435.5	448.2	461.1	319.0	328.9	338.9
2030	454.3	469.5	485.2	337.8	350.1	362.9
2031	453.7	471.5	489.9	337.3	352.0	367.4
2032	453.3	473.4	494.3	336.8	353.9	371.7
2033	452.8	475.0	498.2	336.4	355.6	375.8
2034	452.5	476.4	501.6	336.2	356.3	377.7
2035	452.1	477.8	504.9	336.0	357.0	379.4
2036	451.8	479.2	508.3	335.8	357.7	381.1
2037	451.4	480.6	511.7	335.5	358.9	384.0
2038	451.1	482.0	515.0	335.3	360.0	386.7
2039	450.7	483.3	518.2	335.0	361.1	389.4
2040	450.4	484.5	521.3	334.7	362.2	392.0
2041	450.1	485.8	524.4	334.5	363.2	394.6
2042	449.8	487.0	527.4	334.2	364.2	397.1
2043	449.5	488.3	530.6	334.0	365.3	399.8
2044	449.2	489.6	533.9	333.7	366.3	402.5
2045	448.8	491.0	537.3	333.4	367.5	405.3
2046	448.5	492.4	540.9	333.1	368.8	408.6
2047	448.1	493.9	544.6	332.8	370.1	412.0
2048	447.7	495.4	548.6	332.5	371.5	415.5
2049	447.3	497.1	552.9	332.1	373.1	419.8
2050	446.9	498.9	557.4	331.7	374.8	424.2

4.7 Gross Load Forecast

The Plan utilizes the net load forecast for all planning purposes, but in order to incorporate the impacts of BTM and CSG resources, a gross load forecast was created. Essentially, the gross load was calculated by adding BTM, CSG, and ICS components to the net load forecast, for both demand and energy.

Forecasts are approximated using historical BTM and CSG production data, to simulate the amount of load that was offset via BTM and CSG generation. Historical 2022-2024 BTM production data is collected at a combined class level. Regression analysis is performed to produce BTM production DPC and BTM production UPC forecasts. A customer count forecast is produced by summing the number of BTM customers from class-specific forecasts. These BTM forecasts represent the amount of load that is being offset by the on-premise BTM generators, and take into account historical trends of customers adding BTM to their premise for forecasted growth.

Separately, the CSG production forecast is determined by using historical 2024 demand and energy data, which is then forecasted forward using assumed retirement dates and degradation factors. This CSG forecast represents the amount of load that is being offset by the existing larger scale community solar generators and do not take into account future expansion of planned CSGs or ICS facilities. Planned CSGs will be represented as load modification via CSG and ICS resources in the Capacity Expansion modeling, not as a load forecast.

Resulting BTM and CSG production forecasts can be found in Appendix C.

4.8 Historical Demand and Energy

The Company historically experienced its annual peaks in the summer. Peak demand and annual energy for the period 2021-2025 are provided in Table 4-7. Since 2021, the summer peak has experienced an average annual growth rate of -0.86 percent, the winter peak has experienced an average annual growth rate of 0.44 percent, and the historical annual energy experienced an average annual declining growth rate of -1.84 percent. The all-time peak was recorded in summer of 2019 with a value of 422 MW. Recently, The Company nearly surpassed this all-time peak with a value of 421 MW in July of 2026.

Table 4-7
Historical Peak Demand and Annual Energy

Year	Peak Demand*				Annual Energy*		Summer Load Factor (%)	Winter Load Factor (%)
	Summer (MW)	Summer % Change	Winter (MW)	Winter % Change	GWh	% Change		
2021	407		296		2,051		57.52%	79.08%
2022	410	0.74%	334	12.84%	1,999	-2.50%	55.67%	68.33%
2023	411	0.24%	299	-10.48%	1,940	-2.96%	53.89%	74.08%
2024	394	-4.14%	311	4.01%	1,925	-0.80%	55.61%	70.46%
2025	396	0.51%	299	-3.86%	1,870	-2.85%	53.90%	71.39%
2026	421	6.31%						
Average Annual Growth (%)		0.86%		0.44%		-1.84%		
* Annual demand and energy includes transmission and distribution losses.								

4.9 Forecast Comparison to the 2022 ERP

A comparison of the peak demand and energy forecasts of the 2022 ERP and this 2026 ERP is shown in Table 4-8. In the 2022 ERP, the annual energy growth was projected at 0.31 percent over the 2022-2050 period, as compared to the 0.67 percent growth rate projection in the current plan over the 2026-2050 time period. The annual peak demand growth over the 2022-2050 period was forecasted at 0.27 percent in the 2022 ERP, compared to the peak demand 2026 ERP growth rate projected to be 0.61 percent, as shown in Table 4-8.

Table 4-8
Peak Demand and Energy Forecast Comparison

Year	Annual Energy (GWh)		Peak Demand (MW)	
	2022 ERP	2026 ERP	2022 ERP	2026 ERP
2022	2,112		435	
2023	2,109		442	
2024	2,063		443	
2025	2,076		449	
2026	2,085	1,948	450	432
2027	2,095	1,930	451	430
2028	2,104	2,058	452	448
2029	2,113	2,055	453	448
2030	2,122	2,192	454	470
2031	2,132	2,195	455	471
2032	2,141	2,202	456	473
2033	2,150	2,203	457	475
2034	2,160	2,211	458	476
2035	2,169	2,220	459	478
2036	2,179	2,231	460	479
2037	2,188	2,230	461	481
2038	2,198	2,234	461	482
2039	2,207	2,238	462	483
2040	2,216	2,248	463	485
2041	2,225	2,250	464	486
2042	2,234	2,253	464	487
2043	2,243	2,258	465	488
2044	2,253	2,267	466	490
2045	2,262	2,265	467	491
2046	2,270	2,268	467	492
2047	2,279	2,271	468	494
2048	2,288	2,277	469	495
2049	2,296	2,275	469	497
2050	2,305	2,277	470	499
2022-2050 Ave Growth Rate	0.31%		0.27%	
2026-2050 Ave Growth Rate		0.67%		0.61%

4.10 Energy and Capacity Sales to Other Utilities and Intra-Utility Energy and Capacity Sales and Losses

Pursuant to Rule 3606(a)(III), the Company must provide a forecast of annual energy and capacity sales to other utilities, in addition to capacity sales to other utilities at the time of coincident summer and winter peak demand. The Company does not have any energy or capacity contracts with other utilities and therefore has no data to provide.

Pursuant to Rule 3606(a)(IV), the Company must provide a forecast of annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand. The Company does not have any intra-utility energy or capacity contracts and therefore has no data to provide.

4.11 Load Profiles

Typical day load patterns for Colorado Electric's system load presented for system peak day, average weekday, and average off-peak representative average off-peak days (weekend and holidays) for each calendar month are provided in Appendix D. These monthly load shapes were developed from hourly MSMS data for the year 2024 and reflect average customer use for the system by major customer class.

5.0 Supply-Side Resources

5.1 Existing Owned Resources

The Company's owned generation resources consist of three existing natural gas combustion turbines, two diesel plants, Peak View Wind Project, and 50 percent ownership of the Busch Ranch I Wind Project.

The Rocky Ford diesels are located in Rocky Ford, while the Airport diesels, and the three PAGS combustion turbines are located in Pueblo. The Busch Ranch Wind Project and Peak View Wind Project are located in Huerfano County and Las Animas County, Colorado. The data used for modeling these units are shown in Table 5-1. This table provides information on unit operating parameters for each of the generating facilities. Nameplate capacity is considered to be equivalent to rated capacity. The summer and winter capacity is what is considered dependable capacity. The annual availability is dependent on the timing of major overhauls as well as forced outages.

In this subsection, the Company discusses its owned resources and then discusses the resources procured through PPA's in subsection 5.2. Section 5.3 addresses the Company's portfolio of existing and planned renewable generation and energy storage resources, including Company-owned assets, resources obtained through PPAs, and renewable energy resources available through distributed generation, Community Solar Gardens, and Inclusive Community Solar facilities.

Table 5-1
Existing Owned Generating Facilities

Unit Name	Year Installed	Nameplate Capacity (MW)	Accredited Summer Capacity (MW)	Accredited Winter Capacity (MW)	Forced Outage Rate (%)	Scheduled Outage Rate (%)	Fuel Type	Probable Retirement Date
PAGS LMS100 1	2012	90	62.5	50.6	3.0	3.2	Nat Gas	2047
PAGS LMS100 2	2012	90	62.5	50.6	3.0	2.9	Nat Gas	2047
PAGS LM6000	2017	40	27.7	22.5	3.0	1.1	Nat Gas	2051
Airport Diesels	1964	10.0	6.9	5.6	3.0	0.5	#2 Oil	2033
Rocky Ford Diesels	1964	10.0	6.9	5.6	3.0	0.5	#2 Oil	2029
Busch Ranch I Wind Project	2012	14.5	1.5	1.6	0.0	0.0	Wind	2037
Peak View Wind Project	2016	60	6.4	6.8	0.0	0.0	Wind	2041
Total Capacity			**174.4**	**143.3**				

5.1.1 Diesels

The diesel units commonly known as the Rocky Ford and the Airport Diesels are used for peaking, to support the transmission system, and to provide system reserves. There are five 2 MW diesel units at Rocky Ford. There are four 2.5 MW diesel units at the Airport location.

5.1.1.1 Retirements

The Company retired the Pueblo Diesel unit in 2025; the Commission approved the retirement of these units in the 2022 CEP.

The Airport Diesel units are currently planned to retire in 2033, as approved in the 2022 CEP. The Company is not adjusting this retirement date and will retire these units by the end of 2033.

The Rocky Ford Diesels are currently planned to retire in 2029, as approved in the 2022 CEP. The Company is not adjusting this retirement date and will retire these units by the end of 2029.

The decommissioning costs associated with these retirements consider engineering development, environmental assessments, internal procurement, existing utility terminations, controls relocation, insurance permitting, and decommissioning costs. Based on the estimates of decommissioning the Pueblo diesel units of $570,000, the Company estimates a similar decommissioning price for the Rocky Ford and Airport diesel units. The Company plans to issue an RFP for the decommissioning work and requests Commission approval to create a regulatory asset to track the actual cost of decommissioning the units. The regulatory asset will also capture any remaining netbook value at the time of decommission. At the time of retirement, the estimated netbook value for the Airport Diesel unit is expected to be $185,165 and the net book value for the Rocky Ford Diesel is estimated to be $23,798. The Company will seek recovery of the regulatory asset in a future proceeding.

5.1.2 Pueblo Airport Generating Station

The Company owns two LMS100 natural gas-fired combustion turbines at PAGS that began commercial operation on January 1, 2012, and one LM6000 at PAGS that began commercial operation on December 29, 2016. Together, the three gas-fired combustion turbines contribute 220 MW of capacity and provide dispatchable, firm energy in support of variable, renewable resources. This does not include approximately 200 MW of energy procured from Black Hills' IPP affiliate that is generated at PAGS as well. PAGS is shown in Figure 5-1 below.

Figure 5-1
Pueblo Airport Generation Station

5.2 Existing Purchase Contracts

The Company purchases 200 MW of firm power from Black Hills Colorado IPP, LLC. This power is generated by two natural gas-fired combined cycle ("CC") units at PAGS that began commercial operation on January 1, 2012. This natural gas-fired combined cycle contract is set to expire at the end of 2031. Though not provided for in the current PPA, these PAGS units have the ability to add fast-start technology. This technology would increase the efficiency of the units by eliminating the need for continuous operation, resulting in lower fuel consumption and a significant reduction in emissions.

For the modeling completed for this Plan, the Company assumed that all of the existing purchase agreements were not renewed or extended past the expiration date included in the existing agreements. The Company's existing purchases are outlined in Table 5-2.

Table 5-2
Existing Purchases

Unit Name	Year Installed	Nameplate Capacity (MW)	Accredited Summer Capacity (MW)	Accredited Winter Capacity (MW)	Fuel Type	Probable Retirement Date
PAGS IPP Combined Cycles	2012	200	181.6	181.4	Natural Gas	2031
Busch Ranch I Wind Project	2012	14.5	1.5	1.6	Wind	2037
Busch Ranch II Wind Project	2019	60	6.4	6.8	Wind	2044
Total Capacity			**189.5**	**189.8**		

5.2.1 Coordination Letters

Pursuant to Section 3607(b) of the ERP Rules, utilities must coordinate their ERP plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. The Company does not have any firm contracts or sales of this type with Public Service Company of Colorado or Tri-State Generation & Transmission Association. Therefore, no coordination letters are provided in this Plan.

5.3 Existing and Planned Renewables & Storage

The Company's existing renewable resources include the Busch Ranch I and II Wind Projects, Peak View Wind Project, and amounts of behind-the-meter renewables in the form of photovoltaics ("PV solar"), wind, and storage installed by customers, Community Solar Gardens, and Inclusive Community Solar.

5.3.1 Busch Ranch I and II Wind Projects

The Busch Ranch I Wind Project in eastern Huerfano County, Colorado began commercial operation in October 2012. The Company owns half of the 29 MW project and purchases the energy produced by the remaining turbines under a PPA with Black Hills Colorado Wind, LLC that has a 25-year term from the date of commercial

operation of the facility. This contract expires in 2037. The Company proposed the project pursuant to Rule 3660(h) of Commission Rules 4 CCR 723-3-3650 *et seq.*

The Busch Ranch II Wind Project in eastern Huerfano County, Colorado began commercial operation in November 2019. The Company purchases the energy produced by the 60 MW project under a PPA with Black Hills Electric Generation, LLC that has a 25-year term from the date of commercial operation of the facility. This contract expires in 2044. The Busch Ranch Wind Project is shown in Figure 5-2.

Figure 5-2
Busch Ranch Wind Project

5.3.2 Peak View Wind Project

The Peak View Wind Project in Huerfano County and Las Animas County, Colorado began commercial operation in November 2016. The project consists of 34 GE 1.7-100 class wind turbines. The project was approved by the Commission in Decision No. C15-1182. The Peak View Wind Project is shown below in Figure 5-3.

Figure 5-3
Peak View Wind Project

5.3.3 On-site & Off-site Distributed Resources

The Company has offered solar on-site distributed generation programs to residential, commercial, and industrial customers since 2006. Through these programs, the customers received incentives from the Company to install a PV solar

system on-site and have it interconnected with the Company's grid for parallel operation. These are generally known as behind-the-meter resources. The participating customers received either standard rebate offers or production-based incentives. In return, the Company received the renewable energy credits ("RECs") generated by these systems. The RECs are counted toward the Company's compliance with the state's Renewable Energy Standard. The size of on-site PV solar system was limited by statute to 200% of the customer's average annual consumption at the site.

Concurrently with this filing, the Company is also filing for Commission approval of its 2027-2030 RES Compliance Plan. For the 2027-2030 RES Compliance Plan, the Company is modifying its incentive programs to promote the adoption of customer-located energy storage. Of note, the Company is maintaining its emphasis on its income qualified ("IQ") programs in compliance with SB 21-272.

The Company-sponsored programs focus on storage is a response to market conditions, in which customers are electing to install BTM resources without standard rebates or production-based incentives. These customers only receive net metering services and do not receive additional incentive payment. These customers retain any and all RECs that they generate.

For purposes of the modeling, totals were assumed to encompass all distributed renewable and storage resources. These totals were aggregated to include existing and forecasted resources and are reflected in Table 5-3 below.

Table 5-3
Distributed Resource Capacity

	2026	2030	2035	2040	2045	2050
BTM Resource Capacity (MW)	85	99	98	97	100	113

5.3.4 Community Solar Gardens and Inclusive Community Solar Resources

For several years, through partnerships with third-party developers and CSG owners, the Company has successfully developed new CSG facilities in its service territory through competitive solicitations and standard offers. The first CSG acquisition was in 2014 and the Company has since steadily increased its CSG offerings. While the Company does not own these facilities, it maintains the RECs for RES compliance and in turn offers subscribed customers CSG bill credits funded through the RESA rider. The CSG statute expired on December 31, 2025, and was replaced by the Inclusive Community Solar statute.

The Inclusive Community Solar statute, Section 40-2-127.2, C.R.S., requires that the Company make available 3.5 MW of Inclusive Community Solar facilities in 2026 and

2027. From 2028 and onwards, the Commission shall determine the amount of ICS capacity that the Company is required to make available. For ERP modeling purposes, the Company modeled an assumed 3.5 MW of CSG capacity per year starting in July 2027.

The Company's ICS acquisition will be done as a Standard Offer, in which the capacity will be available on a first-come, first-served basis. The Standard Offer will reserve at least 51% of the available capacity for IQ customers in the Company's service territory as required by § 40-2-127.2(2)(a)(IV), C.R.S.

For purposes of the modeling, totals were assumed to encompass all community solar resources (both CSGs and ICS capacity). These totals were aggregated to include existing and forecasted resources and are reflected in Table 5-4 below.

Table 5-4
Community Solar Resource (CSG and ICS) Parameters

	2026	2030	2035	2040	2045	2050
Community Solar Resource Capacity (MW)	19	33	45	55	51	51

To inform the modeling, the Company used the 3.5 MW ICS capacity mandated by statute in the years of 2026 and 2027 as a benchmark, including 3.5 MW ICS capacity each year from 2027 and onwards. Further analysis of the cost levels and system-value of the community solar resources have made the Company propose different ICS capacity acquisition values from 2028 and onwards. It is up to the Commission to determine the ICS capacity the Company shall acquire. The 2027-2030 RES Compliance Plan provides further details about the Company's proposed ICS acquisition program.

5.3.5 1.8 MW Distributed Generation Wind Facility

CS Wind, a wind turbine manufacturer with a facility located in the Company's service territory in Pueblo, Colorado, has installed on its site a wind turbine (V100 1.8 MW) with a prototype blade system technology to test and demonstrate the ability of the system to generate energy with low wind velocity. The generation from this facility is used by CS Wind at their manufacturing facility, however, Black Hills has an agreement with CS Wind for the RECs from this facility. The REC agreement has a 20-year term from commercial operation and is expected to run through approximately June 2030 based on the project's Commercial Operation Date. This resource was not included among the resources modeled in the ERP; however, its impacts were reflected in the load forecasting process.

5.3.6 Planned Solar Resource

As a result of the 2022 ERP Phase II, the Company contracted for a 200 MW solar resource. The Company will purchase the energy produced by the 200 MW project under a PPA with Honors Energy, LLC located in Pueblo County. The PPA has a fifteen-year term from the date of commercial operation of the facility. At the time of the modeling, commercial operation was estimated to occur in 2028 and was incorporated into the analysis accordingly. Since modeling, the contract has been executed and reflects a commercial operation date of 2029.

5.3.7 Planned Battery Energy Storage System

As a result of the 2022 ERP Phase II, the Company included a 50 MW 4-hour duration battery energy storage system ("BESS") in the current generation resource mix with an eighteen-year battery life assumed. The storage project is a Build Transfer Agreement ("BTA") located at the Company's Pueblo Airport Generating Station in Pueblo County. The BESS will begin commercial operation in 2027 and be transferred to the Company's ownership. Since modeling, the contract has been executed and the CPCN has been approved.

5.4 Candidate Resources Options

Conventional resources, renewable energy resources, and battery energy storage alternatives were analyzed in the evaluation of the resource options for this Plan. The Company engaged Black & Veatch to perform a busbar study of candidate resource options. These resources went through a screening process to determine the most viable resource options.

The Plan modeled fuel-fired, energy storage and renewable resources and analyzed several resource characteristics such as capacity, capital cost, operating cost, and outage rates.[26] Detailed descriptions of these candidate resource options follow.

5.4.1 Conventional Resources

Conventional supply-side resource options were available for selection in the modeling. Most natural gas-fired resources were assumed to be built in the Pueblo area at a "greenfield" or undeveloped site as well as some at a "brownfield" or previously developed site. All capital cost estimates used in the modeling are order-of-magnitude overnight estimates with an accuracy level of ±25 percent. All estimates are based on an engineering, procurement, and construction ("EPC") method of

[26] All of the modeled candidate resource options—including the excluded options—are discussed in detail in Appendix E: Technology Characterization and Busbar Cost Analysis conducted by Black & Veatch and Highly Confidential Appendix F: E3 Technical Report conducted by E3.

contracting. EPC capital cost estimates are exclusive of owner's cost and only consider "inside-the-fence" physical assets. Inside-the-fence physical assets begin with interconnects at the plant boundary (fuel, water, etc.) and end at the high side of the generator step-up transformer.

An important consideration for siting any generating facility is accessibility to transmission. For natural gas-fired units, additional consideration needs to be given to accessibility to natural gas pipelines and availability of natural gas from the natural gas pipeline.[27]

Performance parameter and cost values for modeling conventional resources came from a 2025 study conducted by Black & Veatch for the Company (see Appendix E). The resources from the Black & Veatch study that were evaluated as resource options in this Plan are identified in the following sections.

5.4.1.1 Combustion Turbine

Combustion turbines typically burn natural gas and/or clean fuels and are available in a wide variety of sizes and configurations. CTs are generally used for peaking and reserve purposes because of their relatively low capital costs, higher full-load heat rate, and the higher cost of fuel when compared to conventional base load capacity. Many CTs have the added benefit of providing quick-start and black-start capability in certain configurations. In this analysis, greenfield technology options modeled for CTs included 2x1 LM6000 PF+ CC, 1x1 LM6000 PF+ CC, 1x0 LM6000 PF+ SCCT, RICE, and Mainspring 250 kW Units. Additionally, brownfield sites were included for the gas alternative scenarios which included an additional gas resource for a brownfield combined cycle generation option, which are deliverable and have remaining lifespan, to demonstrate potential cost savings options available to customers. All CT units were assumed to operate on natural gas until 2050 when they operate on renewable natural gas. Renewable natural gas was selected as the clean fuel proxy in this ERP due to its interchangeability with conventional natural gas, infrastructural availability, and applicability of reduced lifecycle GHG emissions through accounting practices resulting from organic waste sources.[28] RNG is available in the CEP scenarios as a fuel for existing and new natural gas-fired resources for forecast year 2050 to allow the model to achieve a 100% greenhouse gas emissions reduction requirement in 2050. For the 2040 Emissions Target scenarios, RNG was allowed as a fuel beginning in 2035. While RNG serves well as a clean fuel source in this Plan, the

[27] Gas price assumptions are described in Section 3.3.1 and represent the forecasted cost of gas supply. There may be increased costs associated with firming the gas supply, and ensuring the pipeline capacity is available to deliver, which is further evaluated through the Company's Gas Supply team.
[28] The Clean Fuel Addendum to Appendix E: Technology Characterization and Busbar Cost Analysis describes renewable natural gas in further detail. For modeling purposes, RNG was assumed to have zero emissions based upon the application of these accounting credits in 2050.

Company will continue to monitor further developments of clean fuels. Parameters used to model each of these CT options are shown on Table 5-5.

Table 5-5
Combustion Turbine Parameters

Parameter	2x1 LM6000 PF+ CC	1x1 LM6000 PF+ CC	1x0 LM6000 PF+ SCCT	1x0 RICE	Mainspring 250 kW Units (10 MW facility)	Brownfield CC Generation
Earliest feasible installation	1/2029	1/2029	1/2029	1/2029	1/2029	1/2029
Size, MW (net)	163	81	45	18	9.6	100
Size, MW (net) - summer	84.5	67.9	41.9	17.3	9.4	76.68
Size, MW (net) - winter	81.5	65.3	40.6	16.8	9.4	73.58
Full load heat rate, Btu/kWh	7,750	7,800	9,450	8,550	8,950	7,500
SO_2 Emission Rate, lb/MWh	0.011	0.011	0.014	0.012	0.013	0.011
NO_x Emission Rate, lb/MWh	0.06	0.06	0.09	0.25	0.05	0.08
CO_2 Emission Rate, lb/MWh	920	930	1,140	1,020	1,050	860
Fixed O&M, $/kW-year (2025 $)	52.86	79.92	174.74	26.80	26.02	84.01
Variable O&M, $/MWh (2025 $)	5.17	5.83	41.01	7.07	4.00	6.41
Forced Outage Rate, %	1.6	1.6	1.6	2.5	3.0%	1.6
Maintenance Outage Rate, %	1.1	1.1	1.1	1.7	2.0%	3.8
Capital Cost, $/kW (2025 $)	4,019	4,468	4,347,	2,950	4,221	1,350

Accredited capacity values for candidate thermal resources were obtained from the effective load carrying capability analysis completed by E3.[29] The capacity contribution of thermal resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand over time. These values are not impacted by the penetration levels of resources, rather they are impacted by unit size and equivalent forced outage rate. Both summer and winter

[29] See Section 6 and Highly Confidential Appendix F – E3 Technical Report.

capacity accreditation show declining ELCCs with larger unit sizes and lower seasonal ELCCs in the winter.

5.4.3 Small Modular Reactor

As a carbon-free firm resource, nuclear generation provides baseload clean energy while providing some flexibility to adjust load to match variable grid demands and renewable generation. While large light water reactor ("LLWR") units are still being built internationally, LLWRs are starting to fall out of favor due to their large capital cost and long construction schedules. For these reasons, consideration for nuclear generation is given to Small Modular Reactors ("SMRs") which are typically less than 300 MWe.

SMRs can be subdivided into Generation III+ ("Gen III+") light water reactors ("LWRs") and Generation IV ("Gen IV") advanced reactors. Gen III+ reactors are similar to the existing Gen III reactors that are operating in the fleet but have advanced passive safety features that are incremental improvements from existing technology. Technology risks with Gen III+ reactors are low. Gen IV reactors are very different from the existing fleet and may still require technology and fuel development. Modeled SMRs assume ownership at a greenfield site. SMRs are expected to be commercially available as early as 2030. Parameters used to model a small modular reactor are shown on Table 5-6.

Table 5-6
Small Modular Reactor Parameters

Parameter	SMR
Earliest feasible installation	1/2030
Size, MW (net)	60
Size, MW (net) - summer	54.5
Size, MW (net) - winter	52.5
Full load heat rate, Btu/kWh	10,500
SO_2 Emission Rate, lb/MWh	N/A
NO_x Emission Rate, lb/MWh	N/A
CO_2 Emission Rate, lb/MWh	N/A
Fixed O&M, $/kW-year (2025 $)	88.30
Variable O&M, $/MWh (2025 $)	28.8
Forced Outage Rate, %	6.3
Maintenance Outage Rate, %	4.38.2
Capital Cost, $/kW (2025 $)	15,000

5.4.4 Seasonal Firm Market Purchased Power

Historically, The Company has assumed the ability to purchase seasonal firm market power due to favorable market conditions. This measure has been used to address short-term peak demand shortfalls and defers the need to install new resources until the need for capacity extends across multiple months. However, the Company has determined that these capacity purchases will be excluded from current modeling efforts due to anticipated constraints in capacity market liquidity and other related uncertainties. The NERC LTRA[30] forecasts capacity deficits in the WECC-Rocky Mountain region starting in the summer of 2034, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period. This regional capacity shortfall, if not addressed, will provide additional downward pressure, potentially shrinking the market availability further.

The projected capacity shortfall is further compounded by changes in the regional market landscape. The expansion of organized wholesale markets, including the Southwest Power Pool (SPP) Regional Transmission Organization (RTO), has reduced the pool of available bilateral trading partners and shifted capacity resources into centralized market constructs. As neighboring utilities join organized markets, traditional capacity trading relationships become less accessible, limiting BHCOE's ability to procure seasonal firm capacity from historic counterparties. This dynamic not only increases long-term capacity procurement risk but also reduces the availability of short-term market-based capacity products that have historically been used to address seasonal peak demand shortfalls. As a result, BHCOE faces a smaller universe of potential counterparties and diminished market liquidity, increasing the risk that sufficient capacity may not be available when needed.[31]

In addition to regional constraints, Colorado law requires transmission-owning utilities to join an organized wholesale market by 2030 or seek a waiver of the requirement. If the Company joins an organized wholesale market, there will be additional reserve margin requirements and associated financial penalties if the requirements are not met. The forecasted reserve margins are inherently uncertain, may fluctuate over time, and could potentially impact anticipated capacity shortfalls due to limited capacity purchase product offerings. It is important to consider that regional markets do not create additional capacity but rather optimize the available resources through its participants. Black Hills continues to monitor developments in western regional market structures, including evolving organized market opportunities, and will evaluate their implications for resource adequacy, reliability, customer costs, and long-term resource planning.

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[30] *Id.* See page 34.
[31] Section 2.7 provides additional details regarding market availability and uncertainty.

5.4.5 Renewable Energy Resources

The renewable energy resource technologies that were modeled in this Plan include PV solar and wind. Data for performance and cost parameters for solar and wind were provided by Black & Veatch.

Renewable energy is variable because its primary energy sources—wind and sun—cannot be precisely predicted. To account for this variability, integration costs and accredited capacity values were reflected in the analysis.

The accredited capacity of variable renewable energy varies by each resource and is typically a small percentage of the nameplate value. In addition, because the generation from variable renewable energy cannot be scheduled, it cannot be dispatched; in other words, it cannot be used to help regulate the balance between supply and demand. The capacity contribution of wind and solar resources is a measure of the ability for these resources to reliably meet demand over time. These values are expected to decline as the penetration of resources of the same type increases. Sections 6.1 and 6.3 provide additional details regarding integration costs and accredited capacity.

5.4.5.1 Photovoltaic Solar

Solar photovoltaic is a variable renewable energy resource that cannot be scheduled and dispatched. Cells generate at their full power when the sun is out and not blocked by clouds. Generation decreases in direct relation to cloud cover. Solar power gradually increases as the sun rises in the morning, peaks early afternoon, and then gradually decreases as the sun sets.

There are three types of racking designs used to orient the panels towards the sun: fixed-tilt, single-axis tracking, and dual-axis tracking. Fixed-tilt racking designs are installed at a fixed tilt and orientation and remain stationery. Single-axis tracking racking designs rotate on a single point to track the sun east to west, moving either in unison, by panel row, or by section. Single-axis trackers are cost-effective and reliable and thus are the most common and what is included in the Plan. They generate between 10–25 percent more energy than fixed-tilt systems. Dual-axis racking designs rotate solar panels on two axes to directly track the sun east to west, and up and down. Dual-axis panels can increase total energy production by 10–15 percent compared to single-axis panels; however, they are more expensive to construct and install, require more land, and therefore are not as cost-effective.

The Company included PV solar facilities for selection in the modeling from different energy resource zones ("ERZs").[32] There are no limitations included in the model on

[32] A map of the ERZs can be seen in Highly Confidential Appendix F: E3 Technical Report.

the amount of solar available in each of the ERZs. Parameters used to model PV solar, which assume a PPA for solar energy, are included in Table 5-7. Parameters can vary for each ERZ and are discussed in detail in E3's Technical Report, Highly Confidential Appendix F.

Table 5-7
PV Solar Performance Parameters

Parameter	50 MW PV Solar	100 MW PV Solar	200 MW PV Solar
Earliest feasible year of installation	1/2029	1/2029	1/2029
Size, MW (net) – summer	16	25	39
Size, MW (net) – winter	1	1	2
Capacity Factor, %[33]	29-30	29-30	29-30
Forced Outage Rate, %	2	2	2
Maintenance Outage Rate, %	0	0	0
Fixed O&M*, $/kW-year (2025 $)	9.35	8.85	8.75
Capital Cost, $/kW (2025 $)	1,776	1,704	1,610

*Does not include integration cost. Integration costs can be seen in Section 6.1

5.4.5.2 Wind

Wind energy generation uses blades to convert kinetic energy into electricity. Wind generating facilities are best located where wind is persistently steady. As the wind turns a wind turbine's blades, the main shaft in the turbine rotates, which in turn drives a generator (situated in the nacelle) to produce electricity. The annual capacity factor of wind varies by location.

A wind turbine shuts down when the wind is either too slow or too fast. Thus, wind is a variable, non-dispatchable energy source. The size of the wind turbine is generally in direct proportion to how much electricity can be generated. Larger wind turbines generate more power, while smaller turbines generate less.

Similar to the PV solar performance parameters and costs, the Company used data provided by E3. The Company included wind facilities for selection in the modeling from different ERZs. There are no limitations included in the model on the amount of wind available in each of the ERZs. Parameters used to model wind in this 2022 Plan, which assume a PPA for wind, are shown in Table 5-8. Parameters can vary for each ERZ and are discussed in detail in E3's Technical Report, Highly Confidential Appendix F.

[33] Capacity factors dependent on ERZs as shown in Highly Confidential Appendix F.

Table 5-8
Wind Performance Parameters

Parameter	50 MW	100 MW	200 MW
Earliest feasible year of installation	1/2029	1/2029	1/2029
Size, MW (net) - summer	18.7	33.7	54.7
Size, MW (net) - winter	19.7	33.9	53.2
Forced Outage Rate, %	4.5	4.5	4.5
Maintenance Outage Rate, %	0.5	0.5	0.5
Capacity Factor, %[34]	32-46	32-46	32-46
Fixed O&M*, $/kW-year (2025 $)	27.40	20.97	20.23
Capital Cost, $/kW (2025 $)	2,112	2,052	1,995

*Does not include integration cost. Integration costs can be seen in Section 6.1

5.4.6 Battery Energy Storage System

Wind and solar are variable renewable energy sources. As such, they cannot be used to maintain the stability of an electric power grid, which requires a delicate balance between supply and demand. Battery storage can alleviate this situation and help provide more reliable energy, or in some cases, firm renewable power.

Battery storage can capture excess variable energy—generation that is not currently needed to meet demand—and store it in other forms until needed. This stored energy can later be converted back to its electrical form and returned to the grid as needed. Stored in high enough amounts, these sources could then be treated as firm power that may be scheduled and dispatched.

Battery storage is a flexible tool for managing the balance between supply and demand. It can be a substitute for generation resource alternatives and can be used in conjunction with generation to help optimize generation capital costs and reduce system operating costs.

Battery storage can also provide power during peak demand times, which can alleviate strain on the power grid and reduce energy supply costs by avoiding purchasing expensive power and operating expensive generation.

Installing battery storage has also been shown to create a number of benefits to the transmission and distribution system. Battery storage can lead to postponing additions and upgrades to distribution circuits, deferring construction or upgrades to substations, and relieving reliability deficiencies.

[34] *Id.* See page 78.

Battery storage is assumed in the model to have a round-trip efficiency of 85 percent and considers storage resources of 4 hours in duration, consistent with the prevailing characteristics of storage available in the market today. There are no limitations to the amount of battery storage that can be built in the model. Battery storage resources are able to provide reserves. Recent legislation related to ITC levels for 2026 through 2050 were included in the development of the storage cost assumptions. Parameters used to model storage in this 2026 Plan, which assume a PPA for storage, are shown in Table 5-9.

Table 5-9
Storage Performance Parameters

Parameter	50MW Lithium-ion Battery	100MW Lithium-ion Battery	200MW Lithium-ion Battery	50MW duration flow battery
Size, MW (net) – summer	43	84	140	32.2
Size, MW (net) - winter	43	72	102	20.6
Efficiency (%)	88	88	88	70
Duration (hours)	4	4	4	10
Fixed O&M, $/kW-year (2025 $)	7.12	7.12	7.12	118
Capital Cost, $/kW (2025 $)	1,816	1,575	1,466	5,900
Capital Cost w/ ITC (2025 $/kW)	1,315	1,140	1,061	4,272

*Does not include integration cost. Integration costs can be seen in Section 6.1

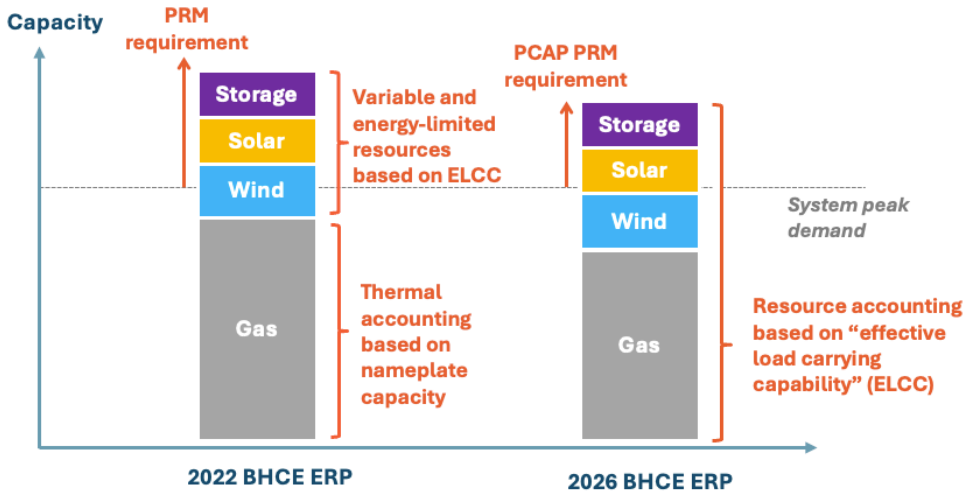
6.0 Reliability Analysis of Evolving Resource Mix and Capacity Accreditation

To comply with SB 19-236's 80 percent emission reduction goal by 2030, the Company anticipates developing or procuring new wind and solar resources in the coming years. The impact that higher levels of wind and solar penetration will have on Black Hills' operation is important to understand so that appropriate steps can be taken to ensure that grid stability is not compromised. Black Hills purchases ancillary services from Public Service Company of Colorado ("PSCo") and incurs tariff service schedule charges for those services from PSCo.

In 2025, the Company contracted with E3 to perform a resource adequacy study on the Black Hills system. The objectives of the study were two-fold: first, to determine the accreditable capacity of renewable and thermal resources for reliability planning purposes; and second, to determine the reliability target through a Planning Reserve Margin Study to maintain system reliability. The study ultimately identified a seasonal summer PRM of 8.5 percent and a corresponding seasonal winter PRM of 18.5 percent for Perfect Capacity planning reserve margins as being sufficient to meet annual reliability requirements. The studies are contained in E3's Technical Report, Highly Confidential Appendix F.

Previously, Black Hills used an Installed Capacity methodology and changed to the Perfect Capacity methodology for the 2026 ERP resource adequacy analysis. The ICAP PRM represents the planning reserve margin, assuming the thermal resources are accredited at 100 percent, while solar, wind, and battery units are accredited using ELCC. This is in contrast to the PCAP PRM, where an ELCC for the thermal resources are accredited as well. Utilizing the PCAP methodology transitions the reliability uncertainty of the thermal resources (for example outages) to be accounted for in the ELCC metrics instead of the PRM value. This results in a lower PRM requirement and reduced thermal ELCC values. The ELCC values for renewables are accounted for similarly in both methodologies. Accounting for thermal and renewable ELCC values in the same manner ensures the resources are better aligned in the capacity expansion analysis. Figure 6-1 illustrates the differences between the two methodologies where the same resource adequacy 0.1 LOLE is met.

Figure 6-1
ICAP and PCAP-based Accounting Framework[35]



Similarly, additional improvements were made to the reliability analysis to incorporate seasonal effects for this IRP. Both PRM and ELCC values incorporate summer and winter analyses to better understand how these impacts change due to weather, solar irradiance, wind production, and storage and thermal availability. Refinement from annual results to summer and winter specific results capture resource and system reliability impacts, ensuring proper future resource selection while maintaining grid stability. Black Hills also incurs ancillary services and integration charges to assist with reliability efforts.

6.1 Resource Integration Costs

Black Hills incurs integration charges for all resources on its system, including existing owned and contracted resources, since Black Hills must purchase ancillary services from PSCo. The integration charges are calculated based on PSCo's Schedule 3 tariff.[36] Schedule 3 costs include Ancillary Service Charges, Variable Energy Resources ("VER"), and Non-Variable Energy Resources ("Non-VER") Generation and Frequency Response charges. The charges for the tariff are in nominal dollars escalated over the modeling horizon. Charges for each resource type are detailed in Table 6-1.

[35] See Highly Confidential Appendix F: E3 Technical Report page 19 in Hearing Exhibit 101, Attachment MJH-1 – Ready to Serve.
[36] See tariff rates in Section 2.a.(i) - PSCo Transmission Formula 2026 Estimate.

Table 6-1
Integration Costs

	Schedule 3 (2026$/kW-month)	Total Integration Cost (2026$/kW-month)	Total Integration Cost (2026$/kW-year)
Wind	$0.2333	$0.2333	$2.80
Solar	$0.1264	$0.1264	$1.52
Non-VER	$0.0080	$0.0080	$0.10

6.2 Resource Adequacy

E3 calculated the accreditable capacity of future thermal, wind, solar, and storage resources using its Renewable Energy Capacity Planning ("RECAP") software. The resulting Effective Load Carrying Capability values quantify the dependable capacity contribution of each resource and were used to evaluate resource portfolios against the Company's reliability requirements. By incorporating ELCC-accredited capacity into portfolio assessments, the Company can determine whether future resource additions provide sufficient dependable capacity to meet its resource adequacy needs and maintain compliance with the reliability standard of 0.1 Loss of Load Expectation, equivalent to no more than one day of expected load loss in ten years. The ELCC values were developed by evaluating the impact of each resource on system reliability and measuring the amount of fully reliable capacity that would provide an equivalent reliability benefit under the Company's 0.1 LOLE planning standard.[37]

To determine the amount of capacity required to satisfy this reliability metric, E3 also conducted a Loss of Load Probability analysis to establish the planning reserve margin requirement. The resulting planning reserve margin reflects the amount of capacity needed above forecast peak demand to maintain the Company's reliability target.

Both the resource accreditation and reserve margin analyses were performed under an islanded-system assumption. Under this assumption, Black Hills was not able to procure capacity from neighboring utilities. This approach provides a conservative assessment of resource adequacy and ensures the Company can maintain reliability using its own resources regardless of external market availability.

6.3 Accreditable Capacity of Wind, Solar, and Storage

E3 evaluated the capacity value of both existing and potential future wind additions across the modeled resource zones. The analysis showed that the capacity value of

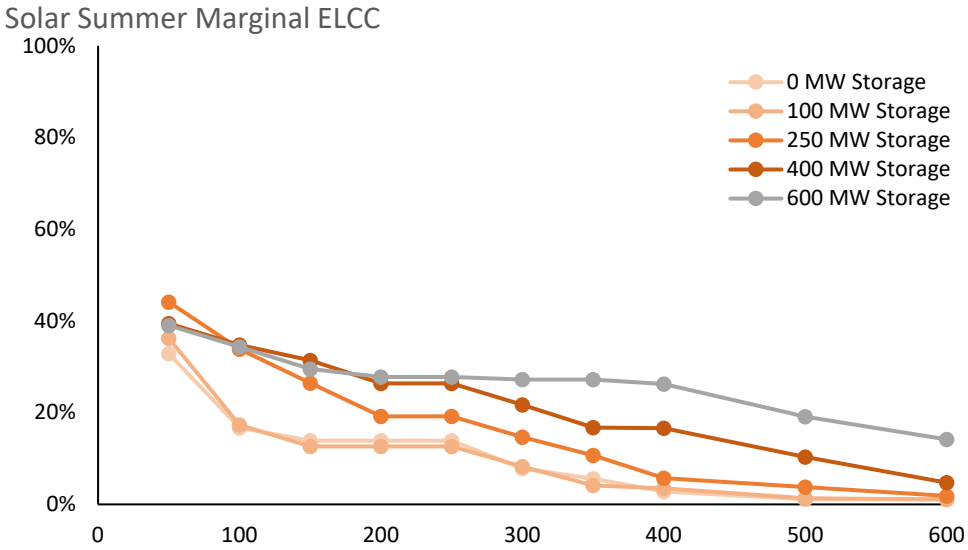
[37] See Highly Confidential Appendix F: E3 Technical Report for more details regarding the resource adequacy analysis.

wind declines as additional wind resources are added to the system due to resource saturation effects. While additional wind generation increases overall energy production, the periods of greatest system need are often characterized by high summer temperatures and relatively low wind output, limiting the reliability contribution of incremental wind resources.

E3 evaluated solar and storage's combined ability to meet system reliability by calculating the capacity value of solar and storage resources in the summer and winter based on existing and planned resources, as well as additional future solar and storage resources from each potential modeling zone. Due to saturation effects, the capacity value of solar alone declines as the system adds more of the same resource. Solar ELCCs increase with additional storage due to diversity effects. Also, additional solar allows storage to retain accredited capacity values at higher penetrations.

The calculated ELCC at different solar, storage, and wind penetrations on the Black Hills system can be seen in Figures 6-2 through 6-6.[38]

Figure 6-2
Calculated Summer Solar ELCC[39]



[38] *Id.* See page 83.
[39] *Id.* See page 83.

Figure 6-3
Calculated Winter Solar ELCC[40]

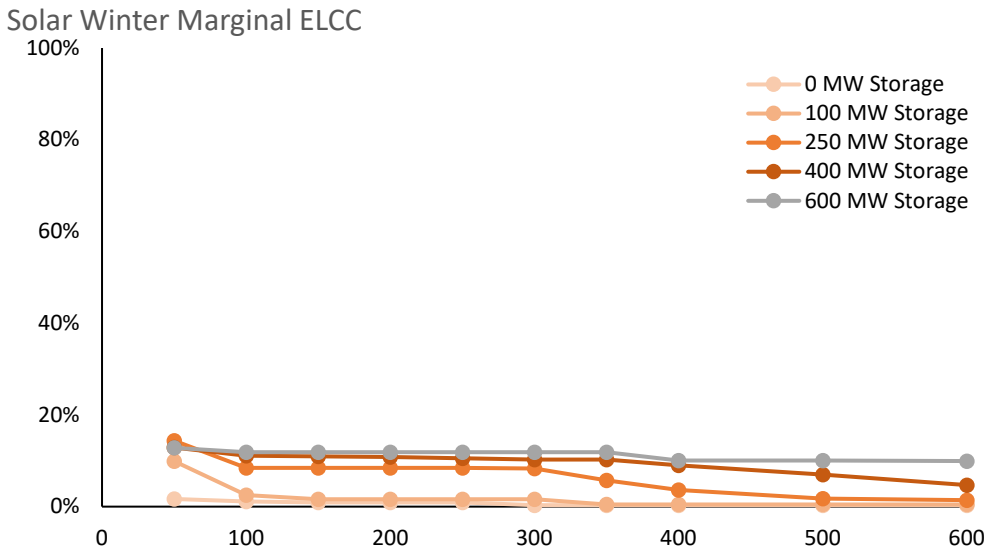
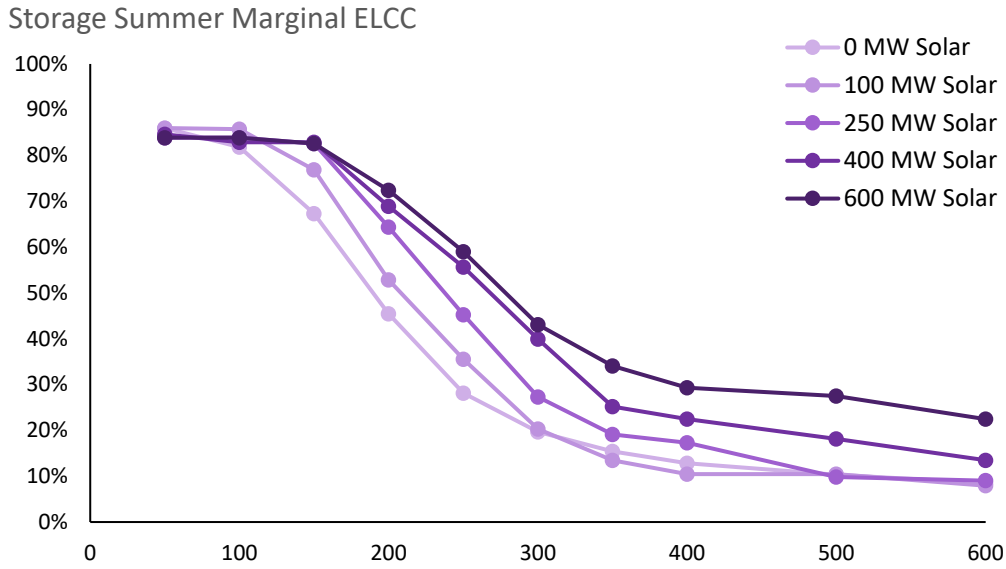


Figure 6-4
Calculated Summer Storage ELCC[41]



[40] *Id.* See page 83.
[41] See Highly Confidential Appendix F: E3 Technical Report page 34 in Hearing Exhibit 101, Attachment MJH-1 – Ready to Serve.

Figure 6-5
Calculated Winter Storage ELCC[42]

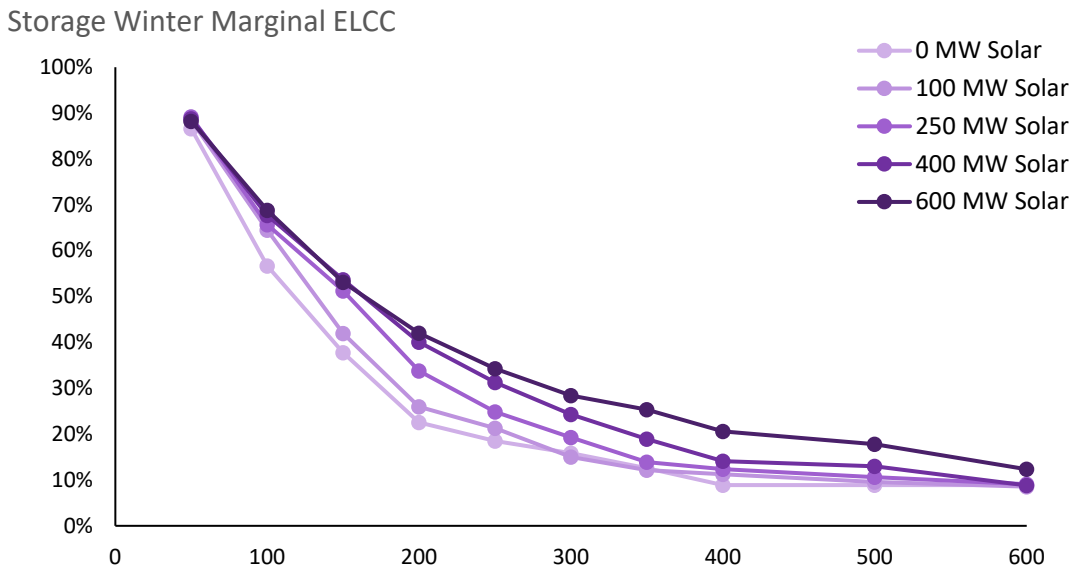
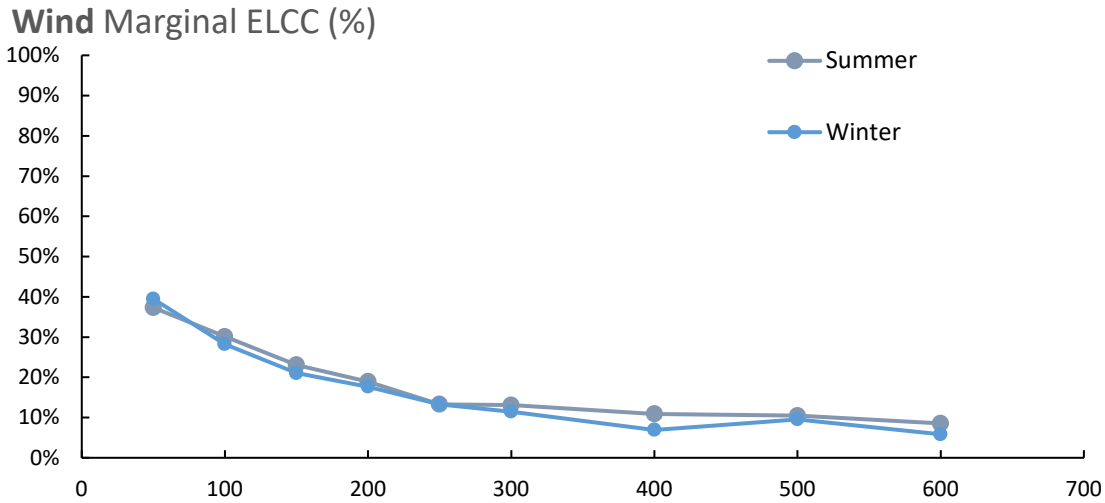


Figure 6-6
Calculated Summer and Winter Wind ELCC[43]



[42] *Id.* See page 83.
[43] *Id.* See page 83.

As an increasing amount of solar comes onto the system, the benefit of similar output profiles leads to diminishing returns since the hours that incremental solar can contribute to key loss of load hours is limited. The increased PV capacity also contributes to the shift in net system peaks to later in the day when there is little to no solar generation. For the future wind additions, the higher ELCC value relative to existing resources is due to better wind quality through geographic diversification. Similar to solar, as more of the same resource is added to the system, the wind capacity contribution declines. Storage allows targeted capacity contributions, and when combined with solar, a diversity benefit is achieved. E3's Technical Report, Highly Confidential Appendix F, provides additional details around this analysis. Tables 6-2 through 6-4 show the ELCC for incremental wind, solar, storage, and solar plus storage additions to the Black Hills system.

Table 6-2
Seasonal Incremental Wind ELCC[44]

Total Wind Nameplate (MW)	Summer Effective Capacity Value (Effective MW)	Summer Incremental ELCC (%)	Winter Effective Capacity Value (Effective MW)	Winter Incremental ELCC (%)
50	19	37%	20	39%
100	34	30%	34	28%
150	45	23%	44	21%
200	55	19%	53	18%
250	61	13%	60	13%
300	68	13%	66	11%
400	79	11%	73	7%
500	89	10%	82	10%
600	98	9%	88	6%

[44] See Highly Confidential Appendix F: E3 Technical Report page 33 in Hearing Exhibit 101, Attachment MJH-1 – Ready to Serve.

Table 6-3
Calculated Summer Solar and Storage ELCC[45]

SUMMER	Solar Nameplate Capacity (MW)										
Storage Nameplate Capacity (MW)	0	50	100	150	200	250	300	350	400	500	600
0		16	25	32	39	46	50	52	54	55	56
50	43	60	68	75	81	88	92	94	96	97	98
100	84	102	111	117	123	130	134	136	138	139	140
150	118	137	149	156	164	171	175	177	179	181	181
200	140	160	176	186	194	203	208	212	213	216	217
250	154	176	193	207	216	226	233	238	241	245	247
300	164	186	204	218	229	239	249	256	261	266	268
350	172	193	210	225	238	249	259	267	274	281	285
400	178	198	215	231	244	258	268	277	285	295	300
500	189	209	226	240	254	267	281	293	303	319	328
600	197	217	234	249	263	276	290	304	317	336	350

Table 6-4
Calculated Winter Solar and Storage ELCC[46]

WINTER	Solar Nameplate Capacity (MW)										
Storage Nameplate Capacity (MW)	0	50	100	150	200	250	300	350	400	500	600
0			1	2	2	3	3	3	3	4	4
50	43	45	46	46	47	47	47	48	48	48	48
100	72	77	78	79	79	80	81	81	81	82	82
150	91	95	99	101	103	106	107	108	108	109	109
200	102	107	112	115	119	123	126	128	128	129	130
250	111	118	122	127	131	135	139	142	144	146	147
300	119	125	130	135	140	145	150	154	156	160	161
350	125	131	136	141	147	152	157	162	166	171	174
400	130	136	142	147	153	158	163	168	173	180	184
500	139	146	151	157	163	168	174	180	186	194	202
600	147	154	160	166	172	178	183	189	194	204	214

6.4 Accreditable Capacity of Thermal Resources

Traditional ICAP methodology assumes thermal resources (such as natural gas) are subject to 100 percent ELCC, or their full installed capacities. The 2026 ERP employs the PCAP methodology, where thermal resources are subject to less than 100 percent ELCC, similar to renewable and storage resources. This helps ensure all resources are on a level playing field, not only in the resource adequacy analysis, but also in the capacity expansion modeling. This was especially important to Black Hills, as several thermal resources expire within the RAP, and additional resources will be needed to meet CEP requirements.

[45] See Highly Confidential Appendix F: E3 Technical Report page 35 in Hearing Exhibit 101, Attachment MJH-1 – Ready to Serve.
[46] See Highly Confidential Appendix F: E3 Technical Report page 35 in Hearing Exhibit 101, Attachment MJH-1 – Ready to Serve.

The capacity contribution of conventional thermal resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand over time. Unlike renewable resources that are based on resource penetration, thermal accreditation is determined by installed capacity size and forced outage characteristics. E3 calculated seasonal summer and winter existing and candidate thermal ELCCs. Both sets show declining ELCCs with larger unit sizes and lower seasonal ELCCs in the winter. Larger units in smaller systems often experience lower ELCC values because their unavailability is closely associated with potential loss-of-load events. However, exceptions exist. E3 notes that the PAGS units achieve relatively high ELCC values for their capacity because outages are typically partial rather than total, which lessens the impact of the large-unit/small-system dynamic.

The calculated ELCC at different generic nameplate capacity sizes on the Black Hills system can be seen in Table 6-5.

Table 6-5
Calculated Seasonal Thermal ELCC by Unit Size[47]

Unit Nameplate (MW)	Summer Effective Capacity Value (Effective MW)	Summer Incremental ELCC (%)	Winter Effective Capacity Value (Effective MW)	Winter Incremental ELCC (%)
10	10	97%	10	95%
20	19	96%	19	93%
40	38	94%	36	91%
50	46	92%	45	90%
60	55	91%	53	87%
80	67	84%	65	81%
100	77	77%	74	74%
200	89	45%	86	43%
400	89	22%	86	22%

[47] *Id.* See page 83.

6.5 Accreditable Capacity of Demand Response Resources

E3 performed a demand response ELCC study to determine capacity accreditation. To simulate the program during the time of year with most critical hours, this study was performed across a summer timeframe with the assumption of a 10 MW program. E3 determined that a higher number of calls per year has a more significant impact on the capacity value when compared to a longer duration. However, there is a steady ELCC value of 65% after two calls per year, except for the 8-hour program which has an ELCC value of 68% with six calls per year. The results are shown in Table 6-6.

Table 6-6
Calculated Demand Response ELCC[48]

		Maximum Number of Calls per Year			
		1	2	4	6
Maximum Duration of Calls (hours)	2	46%	65%	65%	65%
	4	50%	65%	65%	65%
	8	50%	65%	65%	68%

6.6 Planning Reserve Margin

Resource adequacy is the ability of an electric system to serve load across a range of weather and system operating conditions based on a reliability standard. A planning reserve is the amount of capacity that each electric utility must hold in reserve above its annual peak load requirements. A planning reserve margin is a percentage applied to the expected peak load to determine the minimum additional capacity that an electric utility should plan for to ensure that it will meet its peak load obligations in the event of extreme weather, or other unexpected conditions. This Plan's models develop an adequate resource portfolio to cover peak resource requirements plus seasonal PCAP planning reserve margins.

A study completed by E3 used industry standard metrics including Loss of Load Probability modeling to identify a PRM requirement that represents the total capacity needed to maintain a Loss of Load Expectation standard of 0.1 days per year. The resource adequacy analysis used E3's RECAP model to calculate the PRM requirement by simulating hundreds of years of potential conditions using stochastic techniques. This ensures RECAP captures a wide distribution of potential outcomes. It then

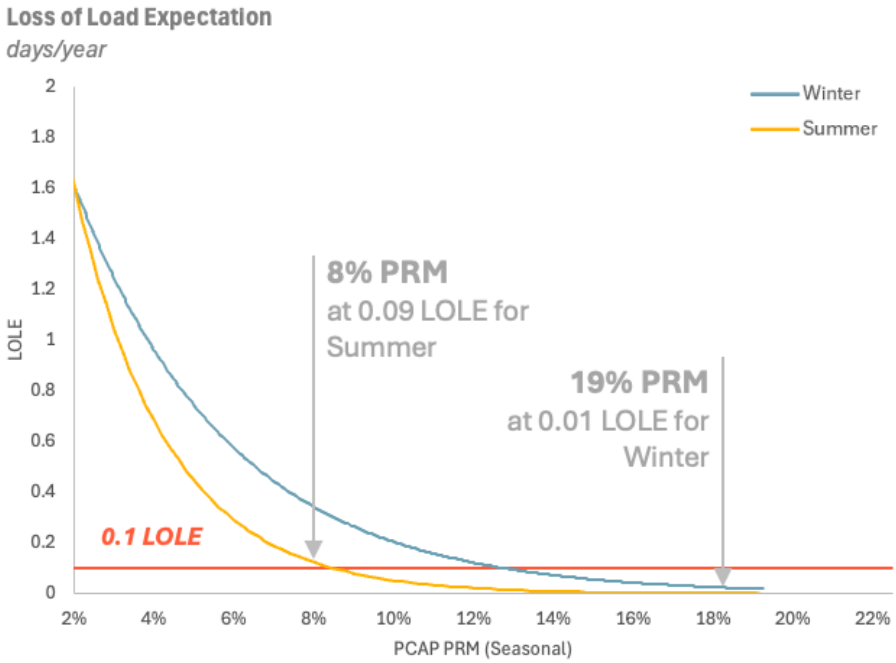
[48] See Highly Confidential Appendix F: E3 Technical Report page 38 in Hearing Exhibit 101, Attachment MJH-1 – Ready to Serve.

determines the frequency, duration, and magnitude of loss of load events across all simulated years and then calculates the LOLE.

E3 analyzed seasonal and annual planning constructs using the 0.1 days per years LOLE standard. The total number of outage days are identified in each season and are then proportionally allocated between summer and winter. This ensures the Black Hills Colorado Electric system maintains an annual target reliability standard of 0.1 days per year LOLE, with a 90/10 summer/winter split in the reliability requirement.

The study ultimately identified a seasonal summer PRM of 8.5 percent and a corresponding seasonal winter PRM of 18.5 percent for Perfect Capacity planning reserve margins as being sufficient to meet annual reliability requirements.[49] The high proportion of firm capacity versus variable capacity along with the switch to the PCAP methodology helps to reduce the planning reserve margin. This is discussed in more detail in Highly Confidential Appendix F, and Figure 6-7 displays the summer and winter relationships between PRM and LOLE

Figure 6-7
2030 BHCOE System PRM and Loss of Load Expectation[50]



[49] E3 used PRM values of 8.4% in summer and 19.6% in winter in PLEXOS based on preliminary RECAP PRM results. These differ by 0.1% in summer and 1.1% in winter when compared to final RECAP PRM results. Final PRM results will be used in Phase 2.
[50] See Highly Confidential Appendix F: E3 Technical Report page 27 in Hearing Exhibit 101, Attachment MJH-1 – Ready to Serve.

Historically, most utilities used PRM methods such as ICAP, which takes thermal resources into account in the PRM requirement only. The emergence of alternative methods in PRM analysis now include options to provide alignment with thermal resource accreditation, which is done with the PCAP methodology. This allows for a level playing field in least-cost portfolio comparison among all resource options.

Neighboring organized markets, in addition to leading industry reports, calibrate their systems based on standard reliability metrics like LOLE, LOLH, EUE, and reliability targets. Regardless of what PRM and ELCC methodologies are used, they are all dependent on the aforementioned reliability metrics. Black Hills has made the transition from ICAP to PCAP, as well as from annual to seasonal granularity for calculating the PRM and ELCC. As more variable and renewable resources are added to the resource mix, and more load is occurring during non-peak hours, there has been a desire to shift PRM methodologies and reliability metrics to capture these uncertainties.

The 2022 ERP used an annual ICAP method and resulting 24 percent PRM, which was later changed to 20% per settlement agreements in Phase II. The current 2026 ERP uses a seasonal PCAP method and resulting 8.5 percent summer PRM and 18.5 percent winter PRM. As a reference, E3 also computed preliminary seasonal ICAP values, which were used to benchmark the PCAP results only. They were not used and have not been included in any modeling for this ERP. This seasonal ICAP method had a resulting 27 percent summer PRM and 54 percent winter PRM. The 27 percent summer PRM value is in line with the 24 percent identified in the 2022 ERP because that study examined summer reliability metrics.

The 2025 WARA PRMA[51] analyzed several PRM metrics, including a Total Reliability PRM ranging from 36.5 percent in 2028 to 49.2 percent in 2034. The 2025 NERC LTRA[52] included PRM values ranging from 30.5 percent in 2023 to 6.9 percent in 2035. Similar to Black Hills, MISO[53] and SPP[54] also use seasonal PRMs, due to the large difference in reliability for technology specific resources. Additionally, Black Hills continues to monitor industry compliance efforts, including energy assurance and computational load risks, while evaluating methodologies best suited to the Black Hills system. Table 6-7 provides a summary of the PRM methodologies and results for various entities demonstrating the reasonableness of Black Hills' seasonal PCAP PRMs.

[51] *Id.* See page 39.
[52] *Id.* See page 34.
[53] *Id.* See page 39.
[54] *Id.* See page 39.

Table 6-7
BHCOE and Regional Planning Reserve Margins

BHCOE 2022 ERP	BHCOE 2026 ERP	NERC 2025 LTRA	WARA 2025 PRMA	MISO 2024 PRM LRR	SPP 2026 PRMR
Annual	Seasonal	Annual, varying	Annual, varying	Seasonal	Seasonal
ICAP - 24%[55]	ICAP - 27% Summer, 54% Winter	51% 2026 > 30.5% 2030 > 6.9% 2035	Total PRM - 36.5% 2028 > 49.2% 2034	ICAP - 15.7% Summer, 38.6% Winter	17% Summer, 38% Winter in 2030
	PCAP – 8.5% Summer, 18.5% Winter		Peak PRM - 25.1% 2028 > 26.9% 2034	UCAP - 7.9% Summer, 25.3% Winter	
Based on LOLE (0.1 day/yr)	Based on EUE, LOLE (0.1 day/yr)	Based on EUE, LOLH, Reliability Target (0.02%)	Based on LOLE (0.1 day/yr), Reliability Target (0.02%)	Based on LOLE (0.1 day/yr Summer, 0.01 day/yr Winter)	Based on LOLE (0.05 day/yr Summer, 0.05 day/yr Winter)

As we see increases in variability across the region, it is important to have dispatchable units capable of responding to unplanned possibilities. Gas units and energy storage offer efficient and fast start capabilities that respond to variability in available energy. Peaking units can provide quick response capabilities in the event of an unplanned outage. Since they are capable of ramping up quickly, they can minimize some of the problems caused by outages and variability. These units operate very efficiently in short frequencies, which keeps costs to customers low when needing to quickly respond to changes in generation. Similarly, energy storage technologies can dispatch rapidly to mitigate short duration impacts, or to provide a bridge resource until another resource solution can occur.

[55] The 2022 ERP resource adequacy analysis produced a 24% ICAP PRM to meet the LOLE requirement of 1 day in 10 years. Through the Settlement Agreement process, a 20% PRM was agreed to, thus temporarily reducing our ability to meet the 1 day in 10 year industry accepted metric. As a part of this Plan, Black Hills will be soliciting for the additional resources that are needed to meet our newly studied PRM and associated LOLE metrics. Reliability has become increasingly important as we continue to incorporate more renewables onto the system, retire existing firm-dispatchable resources, adjust to shrinking market conditions, experience increased frequency and intensity of extreme weather events, and plan for future reliability of our customers.

Of note, the Company was ordered to conduct additional PRM analysis as a result of its 2022 ERP, which has been presented in E3's Technical Report Highly Confidential Appendix F. The request has addressed the impacts of different LOLEs (including an increased LOLE that reduces reliability to 2 days in 10 years) and the inclusion of reliance on outside market support. It is the Company's belief that given the increased industry wide reliability concerns and uncertainty in regional markets, we should continue to conduct resource adequacy analysis as an islanded system to ensure the reliability of our customers. Industry-wide developments, including rapid renewable resource integration, retirements of firm dispatchable resources, tightening market conditions, and the increasing frequency and intensity of extreme weather events, further exacerbate reliability uncertainty and the associated costs under certain market constructs. It is increasingly important to plan for dispatchable, firm resources to support the integration of renewable energy resources in a reliable and cost-effective manner. Until further information can be presented and analyzed in relation to future market conditions, the Company will plan with the NERC recommended 1 day in 10 year LOLE metric reflected in the reliability analysis presented herein, and will closely monitor changing needs going forward. As a part of this Plan, Black Hills will be soliciting in Phase II for the additional resources that are needed to meet our newly studied PRM and associated LOLE metrics.

Spinning and non-spinning contingency reserves have historically been provided to Black Hills Energy through its participation in the Western Power Pool as a sub-entity of Public Service Company of Colorado, where Black Hills could rely on the Western Power Pool for approximately 60 minutes after a forced outage, but then must replace the lost capacity. As of Apil 1, 2026, Black Hills continues to receive this service through the WPP as a sub-entity of the PSCo BA.

Historically, reserve obligations within the PSCo BA were based on a contingency reserve requirement equal to approximately three percent of load and three percent of online generation. However, the Western Power Pool Reserve Sharing Group Committee has approved revisions to the Reserve Sharing Program associated with the retirement of WECC Reliability Standard BAL-002-WECC-3. Effective September 1, 2026, the WPP plans to transition to a fixed annual Contingency Reserve Obligation ("CRO") methodology based on the Reserve Sharing Group's prior-year average doubled Most Severe Single Contingency ("MSSC"), with annual recalculation and potential adjustments for pool- or zone-level deficiencies. As a result, Black Hills' reserve obligation is expected to be determined under this revised methodology rather than the historical 3% load plus 3% generation approach. The Company anticipates that the revised methodology will reduce its contingency reserve obligation relative to historical requirements, although final implementation details and any associated modifications to the PSCo Sub-entity Reserve Sharing Agreement remain under review.

In addition, the WPP has approved extending the contingency reserve restoration period from 60 minutes to 105 minutes while maintaining the existing requirement that reserve resources begin responding within 10 minutes of activation. The Company will continue to monitor implementation of these changes, including any updates to the PSCo Sub-entity Reserve Sharing Agreement, WPP program documentation, and future market participation requirements that could affect reserve obligations.

The utility plans to continue to review this reserve margin in future ERPs especially as renewable resources increase and additional resources are added in the generation mix. Additional PRM study technical details are provided in Highly Confidential Appendix F.

6.7 Resource Adequacy Regional Markets Impact

The resource adequacy frameworks associated with organized markets may influence BHCOE's future resource planning decisions. Participation in organized markets can provide access to greater geographic and load diversity, broader resource pools, and increased regional coordination. However, market participation also subjects entities to formal resource adequacy obligations, including planning reserve margin requirements, capacity accreditation methodologies, forward compliance requirements, and potential financial consequences for non-compliance.

Under SPP Markets+, participants are required to comply with the Western Resource Adequacy Program ("WRAP"), which includes both forward resource adequacy requirements and a regional capacity-sharing framework. Under the SPP RTO, participants are subject to seasonal resource adequacy requirements, capacity accreditation methodologies, and deficiency payment provisions. As these frameworks continue to mature, future planning reserve margins, accreditation values, compliance requirements, and resource-sharing opportunities may affect resource planning decisions and customer costs.

BHCOE expects market resource adequacy constructs to remain an important consideration in future planning cycles and will continue to evaluate evolving market requirements as part of its long-term resource planning process.

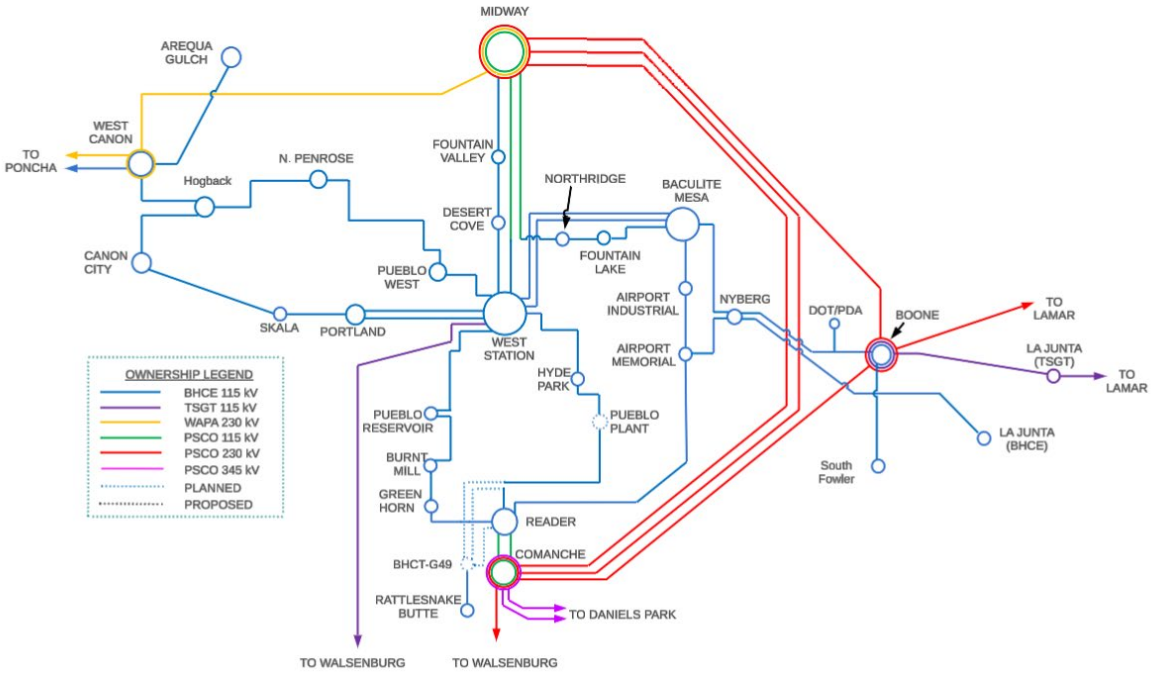
7.0 Transmission System

The Company serves approximately 100,000 customers in south-central Colorado. The counties served are parts of Crowley, Custer, El Paso, Fremont, Otero, Pueblo and Teller. Black Hills serves 21 communities, and of these, the largest communities are Pueblo, Cañon City, and Rocky Ford.

The Company's service territory generally follows the Arkansas River Valley from the Royal Gorge, west of Cañon City, to La Junta, east of Pueblo. The major load centers are the cities of Pueblo and Cañon City with significant smaller load centers in the Cripple Creek area and the area near Rocky Ford.

The Company's transmission system also follows the Arkansas River and consists of 412 miles of 115-kV transmission lines. The Company's transmission system and the interconnection to neighboring entities is shown in Figure 7-1.

Figure 7-1
Existing Black Hills Transmission System



7.1 Local Transmission Planning Process

In this subsection, the Company provides a brief background on its local transmission planning processes. Black Hills recognizes the importance of stakeholder involvement throughout the transmission planning process, and considers a stakeholder to be any person, group or entity that has an expressed interest in participating in the planning process, is affected by the Company's transmission plans, or can provide meaningful input to the process that may affect the development of the Company's final transmission plans.

Stakeholders are encouraged to participate in Black Hills' transmission planning process through the regular meetings held by the Transmission Coordination and Planning Committee ("TCPC") as part of the annual study process under Federal Energy Regulatory Commission ("FERC") Order No. 890. The TCPC is an advisory committee consisting of individuals or entities that are interested in providing input to Black Hills' Transmission Plan. The TCPC study process consists of a comprehensive evaluation of the Black Hills' and surrounding transmission systems to develop an understanding of future transmission constraints, their cause, methods for identifying the constraints and a description of any current or future mitigation plans throughout the 10-year planning horizon. Stakeholders are notified of the initial meeting at the start of the study cycle and invited to participate. An opportunity is provided to comment on the scope of the Black Hills' transmission planning studies. Relevant system modeling data is requested from the stakeholders, as well as any alternative scenario requests. The study cases are compiled, and the data and study scope are finalized. Stakeholder meetings are held in the second and third quarter to review preliminary study results and allow stakeholders to provide additional input into the study scenarios. A final stakeholder meeting is held in the fourth quarter to review the study report. Following this meeting, the final Transmission Planning ("TPL") Assessment is made public for final review and comment. Once the TPL Assessment is finalized, the Local Transmission Plan ("LTP") is drafted and sent out. Following each meeting, contact information for the transmission planner performing the study is provided to allow for ongoing questions or comments regarding the study process. Updates on the progress of the TCPC study efforts are also provided to regional planning groups, such as the Colorado Coordinated Planning Group ("CCPG"), to promote involvement from a larger stakeholder body.

7.2 Regional Transmission Planning Process

In addition to the local TCPC planning process, Black Hills participates in a wider planning effort at the sub-regional and regional levels through the Western Electric Coordinating Council, WestConnect, and the CCPG. WECC is the forum responsible for coordinating and promoting bulk electric system ("BES") reliability in the entire Western Interconnection. The WECC includes committees that focus on transmission planning. The Reliability Assessment Committee ("RAC") provides coordinated

reliability assessments of the Bulk Power System over the planning horizon and provides related advice and recommendations. The Modeling and Validation Subcommittee ("MVS") reviews, recommends, develops and validates system models used to support reliability assessments and other modeling tools that advance the mission of WECC. The Studies Subcommittee ("StS") develops, reviews and approves study programs for reliability assessments to address a variety of potential reliability risks.

WestConnect is one of three planning "regions" within WECC established for regional transmission planning to comply with FERC Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* ("Order 1000"). At the beginning of 2026, WestConnect had 17 members, including 8 Transmission Owners, six Independent Transmission Developers, two State Regulatory Commission members, and one Key Interest Group member. The WestConnect footprint includes ten western states. and includes three sub-regional planning groups ("SPGs"): CCPG, Southwest Area Transmission Group ("SWAT"), and Sierra Subregional Planning Group ("SSPG").

CCPG, which was formed in 1991, is a planning forum that cooperates with state and regional agencies to ensure a high degree of reliability in the planning, development and operation of the transmission system in the Rocky Mountain Region. Many CCPG participants are involved in specialized work groups and subcommittees—for example, the Large Load Task Force and the TPL Studies Work Group—which are responsible for conducting technical, environmental, and cost studies for specific projects, focused geographic areas and/or expansion needs.

Black Hills and the other Transmission Planners in Colorado have a long history of coordinated transmission planning. Given the integrated nature and ownership of the transmission grid in Colorado, coordinated transmission planning has been commonplace in Colorado before it was a requirement.

Internally, and through WestConnect and CCPG, each Company performs annual system assessments to verify compliance with reliability standards, determine related system improvements, and demonstrate adherence to the standards and criteria set forth by the NERC and WECC. Compliance is certified annually.

During the coordinated planning process, a wide range of factors and interests are considered by the Companies, including, but not limited to:

- The needs of network transmission service customers to integrate loads and resources;
- Transmission infrastructure upgrades necessary to interconnect new generation resources involving clean and renewable technologies;

- The minimum reliability standard requirements promulgated by NERC and WECC;
- BES considerations above and beyond the NERC and WECC minimum reliability standard requirements;
- Transmission system operational flexibility, which supports economic dispatch of interconnected generation resources; and,
- Various regional and sub-regional transmission projects planned by other utilities and stakeholders.

This comprehensive internal, regional, and sub-regional planning process ensures that transmission plans continue to be carefully coordinated with all Transmission Planners in the State of Colorado.

7.3 Transmission Constraints

There are constraints that exist on the Black Hills transmission system under circumstances of high-power transfers combined with certain contingency events. These constraints should be taken into consideration when exploring locations for future generation interconnections. Transfer capability limitations on the Black Hills transmission system as they pertain to the future siting of resources are dependent on the location and size of the resource being proposed. For resources sited external to the Black Hills transmission system, limitations may exist at the interfaces between the Black Hills transmission system and the interconnection points with neighboring transmission systems as shown in Figure 7-2. Proposed resources that are sited within the Black Hills system may experience transfer limitations between the resource location and Black Hills' load centers. These limitations are generally evaluated on an individual basis within the generator interconnection request process. The transfer capability of the transfer paths on the Black Hills transmission system is shown in Table 7-1.

As required by FERC Order No. 2023, Black Hills has publicly posted a map that estimates incremental injection capacity on the transmission system.[56] This tool is posted on OASIS and can be used to estimate transmission constraints for different injection points across the transmission system.

As part of Black Hills' Phase II bid evaluation process, it will evaluate transmission reliability associated with its modeled portfolios. Black Hills will also provide a preliminary cost estimate of potential new transmission facilities associated with its 2026 ERP and CEP as part of its 120-Day Report filed in Phase II after the competitive solicitation occurs. Selected bids will then be subject to further study through the Large Generator Interconnection Process ("LGIP") contemplated in Black Hills' Open Access Transmission Tariff ("OATT"). Among other things, the LGIP will identify

[56] https://www.blackhillsenergy.com/bheiici/

interconnection costs and network upgrade costs associated with each selected project, while future transmission studies will evaluate network reliability and/or any network transmission upgrades associated with the selected portfolio.

Figure 7-2
Existing Black Hills Transfer Path Map

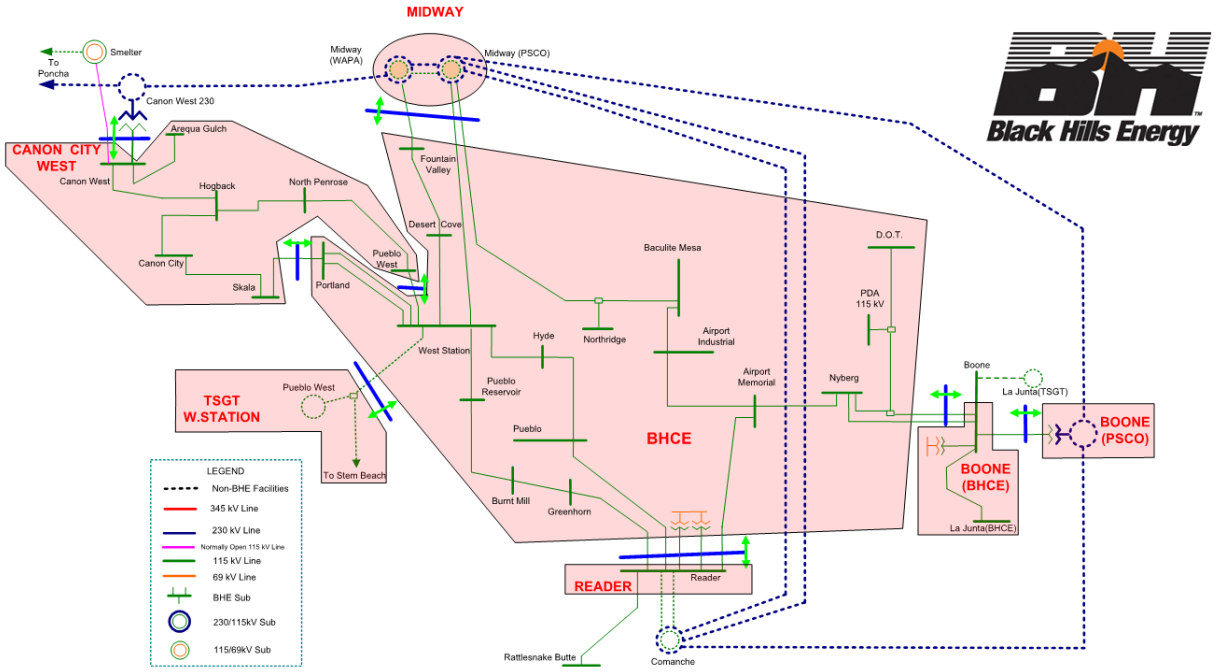


Table 7-1

Transfer Path Capability

Transfer Path	Utility	Total Transfer Capability (MW)
Midway-Black Hills	PSCo, TSGT, & WAPA	320
Black Hills-Midway	PSCo, TSGT, & WAPA	320
Black Hills-West Station	TSGT	145
Black Hills-Reader	PSCo	730
Reader-Black Hills	PSCo	730
Black Hills-Cañon City West	PSCo & WAPA	150
Cañon City West-Black Hills	PSCo & WAPA	150
Black Hills-Boone	PSCo & TSGT	198
Boone-Black Hills	PSCo & TSGT	198

7.4 Transmission Projects

The Black Hills projects included in the 2026 Rule 3627 Filing (Proceeding No. 26M-0051E) and 2026 Rule 3206 filing (Proceeding No. 26M-0005E) largely reflect the continued strategy of infrastructure upgrades and additions to enhance reliability. Since most of Black Hills' projects are reliability-driven equipment replacements or upgrades, the focus on best-cost considerations was narrowed as appropriate.

In the 2026 Rule 3627 Filing, which was the result of an open and coordinated planning approach on regional, sub-regional and local levels, Black Hills documents a procedure to address foreseeable local reliability, integrity and load service issues.

Since the filing of the 2024 10-Year Plan[57], Black Hills has completed the following projects: Pueblo West 115/13.2 kV Distribution Substation, Canon West 230/115 kV Transformer Upgrade, Nyberg – La Junta (Boone Bypass) 115 kV and portions of the West Station – Canon West 115 kV Rebuild. Black Hills identified three planned projects within the upcoming 10-year planning horizon that represent $56 million in capital expenditures between 2025 and 2029. The projects were identified to increase reliability within Black Hills' network transmission system and to meet the requirements associated with expected load growth and generation development. The reliability-driven projects are required under various NERC Reliability Standards to address anticipated system performance issues. Transmission system upgrades related to renewable generation interconnections are discussed below. Planned

[57] See Proceeding No. 24M-0050E.

projects are categorized according to the three distinct geographic areas within Black Hills' Colorado service territory.

Black Hills also annually files with the Commission its planned projects for the next three years in compliance with Rule 3206. In that report, Black Hills identifies the expected in-service date, estimated project cost, location, and compliance with corona noise and magnetic field requirements. The planned and conceptual projects submitted in Black Hills' 2026 compliance filing are shown in Table 7-5.

The Company does not have any proposed transmission additions that are the result of Section 210 of the Federal Power Act or other federal open access transmission (i.e. interconnection or transmission service) requirements, which are discussed in the following section.

7.4.1 Cañon City Area

One project, shown in Table 7-2, addresses reliability and integrity concerns in the Cañon City area.

Table 7-2
Cañon City Area Projects Included in the Black Hills 2025 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
West Station – Canon West 115 kV Rebuild	2026	$41.6	Not required. Decision No. C23-0810

Black Hills' planning process identified this project as a solution for expected concerns regarding reliability and anticipated load growth in the Cañon City area. The West Station – Portland 115 kV line will be rebuilt to replace aging infrastructure and address overloads identified in generation interconnection studies and summer peak operational studies. This is the last portion of the West Station – Canon West 115 kV Rebuild.

7.4.2 Pueblo Area

Two projects, shown in Table 7-3, address reliability and contingency concerns in the Pueblo area. These projects will address transmission overloads identified in transmission planning studies as well as distribution reliability concerns identified in the 2023 Distribution System Plan (DSP).

Table 7-3
Pueblo Area Projects Included in the Black Hills 2026 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
115 kV Pueblo Plant Substation Rebuild	2029	$6.5	Not required. Decision No. C25-0932
Hyde Park 115/13.2 kV Transformer Addition	2027	$4.0	Not required. Decision No. C25-0932

The 115kV Pueblo Plant Substation will be rebuilt to address the limiting substation equipment and improve load serving redundancy. The Hyde Park 115/13.2 kV transformer addition will address N-1 risks and expected load growth. The Hyde Park transformer addition will also offload the Pueblo Plant substation to support the 115 kV Pueblo Plant Substation Rebuild.

7.4.3 Rocky Ford Area

One project, as shown in Table 7-4, addresses reliability concerns in the Rocky Ford area.

Table 7-4
Rocky Ford Area Projects included in the
Black Hills 2026 10-Year Plan

Project Name	In-Service Date	Cost (millions)	CPCN
La Junta 115/69 kV Transformer Upgrade	2029	$3.9	Not required. Decision No. C25-0932

The La Junta 115/69 kV Transformer Upgrade will mitigate overloads that have been identified in annual transmission planning studies and summer peak operational studies. The overloads are currently mitigated with local diesel generation. The diesel generation is expected to be retired in 2029 and will no longer be available for operational mitigation.

Table 7-5
Black Hills 2026 Rule 3206 Planned Transmission Projects

Project	Length and Location	In-service Date	Estimated cost (millions)	Terminal Points	Voltage and MW Rating	Commission Decision/ Proceeding	Description
West Station – Canon West 115 kV Rebuild	41 miles; Pueblo & Fremont Otero County, CO	2026	$31.5M	West Station, Canon West	115 kV; 221 MVA	C23-0810	Rebuild the 115 kV lines from West Station to Canon West to 221 MVA
Pueblo Plant 115 kV Substation Rebuild	Pueblo, CO	2029	$6.5M	Pueblo Plant Substation	115 kV; 221 MVA	C25-0932	Rebuild the Pueblo Plant 115/13.8 kV Substation
La Junta 115/69 kV Transformer Upgrade	Otero County, CO	2029	$3.9M	La Junta Substation	115 kV; 50 MVA	C25-0932	Upgrade the La Junta 115/69 kV transformer to 50 MVA and upgrade limiting terminal equipment
Hyde Park 115/13.2 kV Transformer Addition	Pueblo County, CO	2027	$3.5M	Hyde Park Substation	115 kV, 30 MVA	C25-0932	Add second 115/13.2 kV transformer at Hyde Park

Table 7-5 (continued)

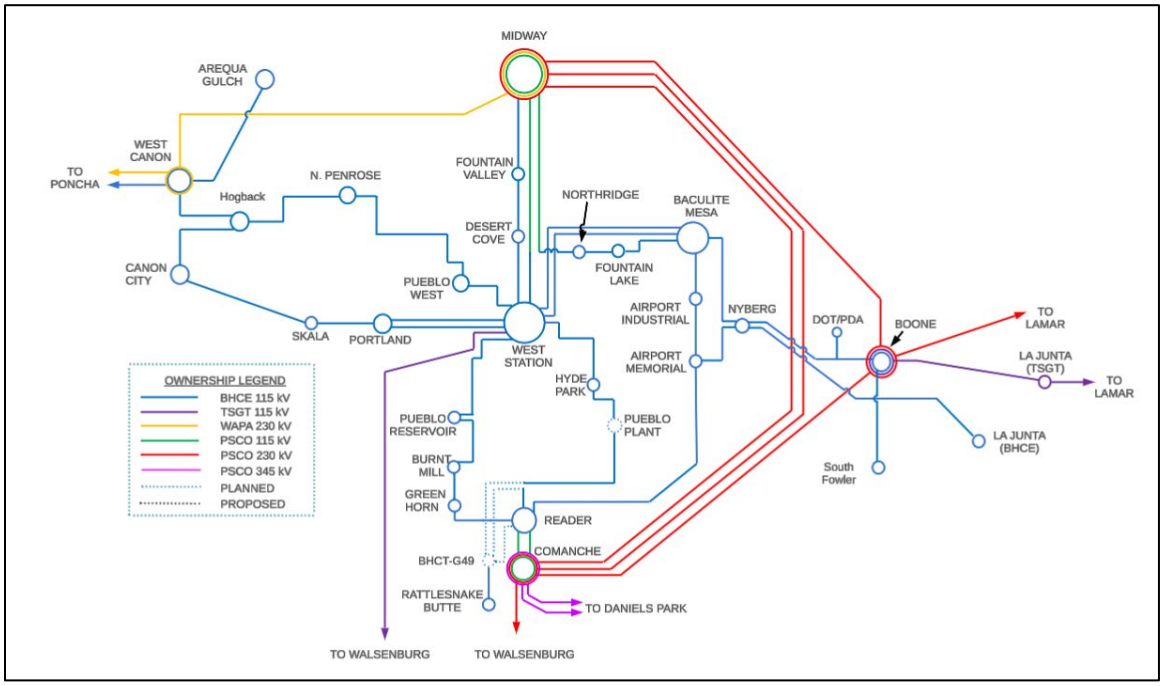
Black Hills 2026 Rule 3206 Planned Transmission Projects

Project	Length and Location	In-service Date	Estimated cost (millions)	Terminal Points	Voltage and MW Rating	Commission Decision/ Proceeding	Description
Nyberg La Junta 115 kV (Boone Bypass)	Otero County, CO	2025	$0.4M	Nyberg 115 kV, La Junta 115 kV,	115 kV; 50 MVA	C25-0932	Tie existing Boone – La Junta and Boone – Nyberg 115 kV lines together and remove extension into Boone substation
BHCT G49 115 kV Interconnection Substation	Pueblo County, CO	2029	$10.4M	New BHCT G49 Interconnection Substation	115kV	TBD	New 115 kV substation on the Reader – Rattlesnake Butte 115 kV line to interconnect the BHCT G49 200 MW solar project
Reader to BHCT G49 to Pueblo Plant 115 kV Cut-In	9 miles, Pueblo County, CO	2029	$13.6M	Reader, BHCT G49, Pueblo Plant	115 kV	TBD	Cut and extend the Reader to Pueblo Plant 115 kV line in and out of the BHCT G49 interconnection substation
Reader to BHCT G49 115 kV Reconductor	11.3 miles, Pueblo County, CO	2029	$4.0M n	Reader, BHCT G49	115 kV, 341 MVA	TBD	Reconductor the G49 to Reader 115 kV line using high ampacity conductor
Pueblo Reservoir 115 kV Terminal Upgrades	Pueblo County, CO	2029	$0.25M	Pueblo Reservoir 115 kVn	115 kV; 231 MVA	TBD	Replace the breaker and line jumper conductors at the Pueblo Reservoir 115 kV substation to increase the facility rating of the West Station – Pueblo Reservoir – Burnt Mill 115 kV lines

All of the projects shown in Table 7-5 and included in Black Hills' 2026 Rule 3206 filing are tentatively planned to be complete and in service during the RAP. Figure 7-3 shows the current Black Hills transmission system with the planned projects identified by dashed lines.

Figure 7-3

Planned and Conceptual Black Hills Transmission System



7.5 Senate Bill 07-100 Transmission Projects

Colorado SB 07-100, codified at § 40-2-126(2), C.R.S., requires Colorado's rate-regulated utilities to continually evaluate and, where necessary, improve their electric transmission facilities to meet the State's current and future energy needs. Historically, utilities' reports were due on October 31 of each odd-numbered year. However, the Commission modified its rules in Proceeding No. 17R-0489E, Decision No. R17-0747, to allow the filing of the SB 07-100 report in conjunction with the biennial 10-Year Transmission Plan filed pursuant to Rule 3627. Under SB 07-100, utilities are required to provide the following information:

(a) Designate Energy Resource Zones;
(b) Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones;

(c) Consider how transmission can be provided to encourage local ownership of renewable facilities, whether through renewable energy cooperatives as provided in Colo. Rev. Stat. § 7-56-210, or otherwise; and
(d) Submit proposed plans, designations, and applications for Certificates of Public Convenience and Necessity to the Commission for simultaneous review.

The Black Hills' 2025 SB 07-100 Study[58] summary is contained within the 2026 10-Year Transmission Plan filed by PSCo, Tri-State, and the Company. For the 2025 SB07-100 cycle, Black Hills referenced recent Large Generator Interconnection ("LGI") studies to evaluate the resource injection capacity from ERZ-5. All generators in the Black Hills generator interconnection queue are within ERZ-5. Recent LGI studies used a 2030 Heavy Summer ("HS") model to identify any adverse impact to the reliability and operating characteristics of the Western Electricity Coordinating Council bulk electric transmission system and, more specifically, to the Black Hills and surrounding transmission systems. Steady state voltage and thermal analyses examined system performance without additional projects to establish a baseline for comparison. Performance was re-evaluated with resource injections modeled and compared to the baseline performance to determine the impact of the injection of new generation on area transmission reliability. Black Hills also recently published an interactive heatmap that can be used to estimate incremental injection capacity for FERC Order No. 2023 compliance. This tool can be accessed with a link on OASIS. The map provides an approximation of the results of a network resource interconnection service request for a specific injection amount at tested points on the network. The heatmap results are informational only but can provide insight into transmission constraints related to energy resources in ERZ-5.

The following transmission projects were identified as necessary to deliver electric power consistent with the development of energy resources located in ERZ-5. The BHCT-G19, BHCT-G21, and BHCT-G38 LGI studies all identified a need to increase the rating of the Airport Industrial – Baculite Mesa 115 kV line. This rating increase can be accomplished with terminal upgrades and a reconductor using ACCC or other advanced conductor technology. The BHCT-G28 and BHCT-G38 LGI studies also identified a need to increase the rating of the Reader – Airport Memorial 115 kV line. This rating increase can be accomplished with terminal upgrades. In 2025, Black Hills completed several 115 kV line rebuilds from West Station to West Canon that were identified as Network Upgrades for BHCT-G29. The 200 MW solar project went into suspension, but the rebuilds were completed to replace aging infrastructure. These recently completed projects improve the injection capability for projects in ERZ-5. The BHCT-G35 and BHCT-G49 LGI studies identified a need for increased capacity between the Rattlesnake Butte and Reader 115 kV substations. LGI studies in this area

[58] *See* Joint 10-Year Transmission Plan, filed in Proceeding No. 23M-0051E by Public Service Company of Colorado, BHCE, and Tri-State, filed on February 1, 2026, at 99-100.

have also shown thermal loading concerns on the Reader – Pueblo Plant – Hyde Park 115 kV lines. The BHCT Transitional Custer Study found the best solution is to cut an existing 115 kV line in the area to bring another source to the point of interconnection.

8.0 Future Resource Analysis and Selection

In this Section, the Company provides information regarding its assessment of need for additional resources as required by Rule 3610. Rule 3610 directs that energy and demand forecasts are compared against the existing level of resources and planning reserve margin to assess the utility's need to acquire additional resources during the RAP. The foregoing analysis provides an assessment of resource need without considering the need for additional clean energy resources pursuant to Colorado's environmental goals. This Section also addresses what resources are needed, considering Colorado's clean energy targets.

8.1 Resource Need

The Company developed a load and resource balance to assess the ability of existing generation resources to meet its forecasted total capacity requirement. Years in which forecasted demand plus planning reserves exceed available generation capacity indicate the need for additional generation resources. Based on the peak demand forecast developed by the Company, planning reserve margin and existing generation resources, the Company will have a capacity deficit beginning in 2026 and continuing throughout the RAP. It is anticipated that without the assurance of seasonal firm market purchases due to the anticipated constraints in capacity market liquidity and other related uncertainties,[59] the Company will need to closely monitor resources and loads, in combination with using firm economy energy purchases (if available) to cover this deficit until additional resources can be available in 2029. Market purchases are not prudent planning for the long term with the uncertainty of available capacity given the current market conditions. It is important the Commission acts expeditiously to ensure proper long-term resource procurement can be obtained.

The load and resource balance for the RAP, which includes the base load forecast and existing resources, is shown in Table 8-1. The load and resource balance for the entire Planning Period is included in Appendix G-1.

[59] Sections 2.7 and 5.4.4 provide additional details regarding market availability and uncertainty.

Table 8-1
Load and Resource Balance (2026-2032)

	2026	2027	2028	2029	2030	2031	2032
Peak Demand	438	441	443	445	447	449	450
DSM	7	11	15	17	17	17	17
Econ Development	0	0	20	20	40	40	40
8.5% Reserve Margin (MW)	37	37	38	38	40	40	40
Net Peak Demand Plus Reserves	432	430	448	448	470	471	473
Existing and Proposed Resources and Purchases*							
Airport Diesels	7	7	7	7	7	7	7
Rocky Ford Diesels	7	7	7	7			
PAGS LMS100 1	62	62	62	62	62	62	62
PAGS LMS100 2	62	62	62	62	62	62	62
Busch Ranch I Ownership	2	2	2	2	2	2	2
Peak View Ownership	6	6	6	6	6	6	6
PAGS LM6000	28	28	28	28	28	28	28
PAGS CC PPA	182	182	182	182	182	182	
Busch Ranch I PPA	2	2	2	2	2	2	2
Busch Ranch II PPA	6	6	6	6	6	6	6
50 MW Battery Storage Ownership			43	43	43	43	43
200 MW Solar PPA			39	39	39	38	38
Total Resources and Purchases	364	364	446	446	439	438	257
Peak Plus Reserves	468	466	486	486	509	512	514
Capacity Excess/Deficit MW	-104	-102	-40	-41	-71	-73	-257
Capacity Excess/Deficit %	-22%	-22%	-8%	-8%	-14%	-14%	-50%

*Summer rated capacities shown.

8.2 Modeling Methodology

Capacity expansion and production cost modeling were conducted to determine the portfolio of future resources that meets the needs of Black Hills' customers over the Planning Period in the least cost manner, while maintaining system flexibility and complying with environmental laws and regulations. Subsequent to those analyses, the Company conducted scenario analysis. Utilities must plan for future customer needs for electricity in an environment of significant uncertainty. Thus, the analysis conducted for this Plan examined uncertainty under a variety of possible future conditions, as reflected in the scenario analysis.

Capacity expansion modeling is a process used to determine the appropriate type, size, and timing for economic resource additions for utilities. The utility's existing

generation resources and future resource alternatives are input into a capacity expansion model with a forecasted load. The model simulates utility operation and "serves" the forecasted load with the utility's existing resources and economically "selects" additional resources from the list of available resource alternatives. The typical criterion for evaluation is the expected total costs subject to meeting load plus reserves and various resource planning constraints, such as Colorado's RES and CEP legislation.

Production cost modeling simulates the hourly operation of the resources available to a utility and is used to forecast system cost and risk exposure. A production cost model includes an hourly dispatch model, with a load forecast and fixed resources to serve that load. The model simulates a given load every hour, then economically serves that load with the available resources, and captures the associated cost. Production cost modeling can also be completed using multiple iterations with changing variables. This form of modeling measures risk associated with the modeled plan subject to changing variables.

Scenario analysis was conducted during which the Capacity Expansion module was used to derive optimal resource expansion plans. The scenarios include variations in inputs representing the significant sources of portfolio cost variability and risk. These inputs include the load forecast, the price of natural gas, and potential enactment of social cost of carbon or other similar mechanisms.

Utilities must plan for the future electricity needs of their customers in an environment of significant uncertainty. Thus, the analysis conducted for this Plan examined resource needs under a variety of possible future conditions.

All of the deterministic modeling used in the Plan analysis was performed by E3 using the PLEXOS LT and PLEXOS ST proprietary modeling software. The Company retained E3 to provide analytical services in support of this Plan. An overview of the modeling software is described in Appendix M.

8.3 Base ERP Plan Analysis and Alternatives

Rule 3604(k) of the Commission's ERP Rules requires that the resource plan contain:

> Descriptions of at least three alternate plans that can be used to represent the costs and benefits from increasing amounts of renewable energy resources, demand-side resources, or Section 123 resources as defined in paragraph 3602(q) potentially included in a cost-effective resource plan. One of the alternate plans shall represent a baseline case that describes the costs and benefits of the new utility resources required to meet the utility's needs during the planning period that minimize the net present value of revenue requirements and that

> complies with the Renewable Energy Standard, 4 CCR 723-3-3650 et seq., as well as with the demand-side resource requirements under § 40-3.2-104, C.R.S. The other alternate plans shall represent alternative combinations of resources that meet the same resource needs as the baseline case but that include proportionately more renewable energy resources, demand-side resources, or Section 123 resources. The utility shall propose a range of possible future scenarios and input sensitivities for the purpose of testing the robustness of the alternate plans under various parameters.

The process used to determine the base resource portfolio for the Company over the planning horizon began by examining scenarios to meet the RES and/or CEP as well as alternative scenarios with higher levels of renewable energy resources. As per the Rules, one of these plans shall represent a base case that describes the costs and benefits of the new utility resources required to meet the utility's needs during the planning period that minimizes the PVRR and that complies with the RES as well as the demand-side resources requirements. In addition, C.R.S. § 40-2-125.5(4)(III) requires the Company to distinguish between the resources needed to meet customer demand in the resource acquisition period and the additional resources that are needed to meet the clean energy targets. Thus, both the rules and statute require a base plan against which to compare other plans. The Company developed such a base plan and refers to this base plan as the Base ERP Plan No SCC.

Additionally, and consistent with Rule 3604(k), the Company modeled alternate plans to demonstrate the costs and benefits for increasing amounts of renewable energy resources, demand-side resources, and energy storage. Consistent with § 40-3.2-106, C.R.S., the Company also modeled portfolios that included the SCC and SCM. In addition, the Company modeled portfolios that would achieve faster emissions reductions, assume low/high load, and various other scenarios as sensitivities. The additional resource scenarios are discussed in more detail in Section 8.5.1 and 8.6. In total, the Company modeled 14 total resource portfolios. These portfolios represent a base case as well as a variety of alternate plans under varying scenarios' assumptions and goals.

8.4 Retail Rate Impact Analysis

The Company proposes to simplify the framework used to recover the costs for existing resources as well as for any candidate resources that may come online in the future. The simplified cost recovery framework entails recovering the actual costs associated with system level (which is utility-scale generation) through existing recovery mechanisms including the ECA, and distribution level resources through the RESA. The appropriate recovery mechanism to recover the costs for new resources will be determined during the Phase II process of the Ready to Serve Plan. The Company proposes to recover ICS costs through the ECA.

Resulting from its most recently concluded Phase II ERP, the Company has begun recovering the costs associated with its PAGS Unit 7, a 50 MW battery storage facility, through the ECA. The Company will also recover the costs associated with a 200 MW solar PPA through the ECA when the facility comes online.

Based on modeling conducted by E3, the Company's preferred portfolio includes the following estimated costs, including those for new system level resources incurred during the RAP as shown in Table 8-2.

Table 8-2
Estimated ECA Costs During the RAP ($000s)

Resource	2027	2028	2029	2030	2031	2032
New Resource Build Cost						
Natural Gas	$0	$0	$6,531	$19,895	$19,895	$47,870
Wind	$0	$0	$20,071	$20,077	$20,082	$25,619
Battery	$0	$0	$0	$0	$0	$29,880
Estimated Generation Cost	$9,700	$7,186	$7,667	$7,402	$6,942	$18,108
Estimated System Purchases	$57,532	$66,461	$63,817	$69,110	$71,518	$45,634
PAGS Unit 7 Cost	$3,748	$8,010	$7,865	$7,488	7,166	6,896
ICS Cost	$0	$0	$779	$1,559	$2,004	$2,004

In addition, the Company is proposing to increase the RESA surcharge from 1.5% to 2%. As stated above, the Company's proposed cost recovery framework includes the recovery of actual distribution level costs aside from ICS facilities through the RESA. This is a departure from the current cost recovery framework in which the avoided costs associated with distribution level resources are recovered through the ECA and the incremental costs associated with those resources are recovered through the RESA. As explained in greater detail in the Company's 2027-2030 RES Plan, allowing the total actual costs associated with distribution level resources to flow through the RESA simplifies how cost recovery occurs. The shift of cost recovery is net neutral – with costs being shifted away from the ECA and to the RESA. The biggest driver necessitating the increase of the RESA surcharge is the costs associated with CSG and ICS facilities. The Company projects that the costs for CSG facilities alone may exceed the revenues that the Company collects through a 2% RESA surcharge beginning in 2029 and will continue to monitor for any future adjustments that may be needed.

8.5 Base ERP Analysis

The ERP first examined a base plan that describes the costs and benefits of the new resources required to meet load needs during the entire Planning Period – a plan that minimizes the PVRR with consideration for social cost of carbon. The ERP refers to this as the Base ERP Plan.

The Capacity Expansion model developed the Base ERP Plan by using logic to economically select the resources to meet the forecasted load throughout the Planning Period.

The model assumed the following:

- All existing resources included as available resources
- SCC and SCM applied during Planning Period
- Base peak demand and annual energy forecasts[60]
- Base natural gas, clean fuel, and economy energy forecasts[61]
- No seasonal firm market purchases allowed
- Conventional, renewable, and battery energy storage resource options[62]

8.5.1 Scenario Analysis

Scenario analysis was conducted during which the Capacity Expansion module was used to derive optimal resource expansion plans. The scenarios include variations in inputs representing the significant sources of portfolio cost variability and risk. In addition, the Production Cost module was used to evaluate granular variations in dispatch. The two fundamental scenarios that were evaluated are Base ERP and Clean Energy Plan. A brief description of the variables for these scenarios, and their corresponding variations, are listed below:

Fundamental & Core Scenarios:

1. Base ERP Scenario
    - Assumed variables as described in Section 8.5
2. Base ERP No SCC Scenario
    - Investigated the impact no SCC and no SCM would have on the Base ERP resource portfolio
    - Removed the SCC and SCM assumptions
    - Assumed all other modeling variables as described in "Base ERP Scenario"

[60] Described in "Base Peak Demand and Annual Energy Forecasts" in Section 4.4.
[61] Described in "Fuel and Market Prices" in Section 3.3.
[62] Described in "Candidate Resource Options" in Section 5.4.

3. Clean Energy Plan (CEP) Scenario
    - Investigated the impact meeting Clean Energy Plan requirements would have on the Base ERP resource portfolio
    - Required 80% CO_2 emissions reduction by 2030 and 100% clean energy by 2050
    - Base renewable natural gas forecast included for clean fuels CEP constraints
    - Assumed all other modeling variables as described in "Base ERP Scenario"
4. CEP No SCC Scenario
    - Investigated the impact no SCC and no SCM would have on the CEP resource portfolio
    - Removed the SCC and SCM assumptions
    - Assumed all other modeling variables as described in "CEP Scenario"

Standard Scenarios:

5. CEP Increased Electrification Scenario
    - Investigated the impact increased electrification would have on the CEP resource portfolio
    - Replaced the base load forecast with the increased electrification forecast, inclusive of vehicle electrification
    - Assumed all other modeling variables as described in "CEP Scenario"
6. CEP Low Load Scenario
    - Investigated the impact lower than forecasted load growth would have on the CEP resource portfolio
    - Replaced the base load forecast with the low load forecast
    - Assumed all other modeling variables as described in "CEP Scenario"
7. CEP High Load Scenario
    - Investigated the impact higher than forecasted load growth would have on the CEP resource portfolio
    - Replaced the base load forecast with the high load forecast
    - Assumed all other modeling variables as described in "CEP Scenario"
8. CEP Low Gas Scenario
    - Investigated the impact low natural gas prices would have on the CEP resource portfolio
    - Replaced the base natural gas forecast with the low natural gas forecast
    - Replaced the base economy energy price forecast with the low economy energy forecast
    - Assumed all other modeling variables as described in "CEP Scenario"
9. CEP High Gas Scenario

- Investigated the impact high natural gas prices would have on the CEP resource portfolio
- Replaced the base natural gas forecast with the high natural gas forecast
- Replaced the base economy energy price forecast with the high economy energy forecast
- Assumed all other modeling variables as described in "CEP Scenario"

Gas Alternative Scenarios:

10. CEP No Gas Builds Scenario
    - Investigated the impact no new gas resources would have on the CEP resource portfolio
    - Allowed only renewable, storage, and SMR resources to fill capacity deficits
    - Existing gas resources are assumed to not be replaced with gas resources
    - Assumed all other modeling variables as described in "CEP Scenario"
11. CEP No SCC (Discounted Gas) Scenario
    - Investigated the impact allowing brownfield gas generation to be selected would have on the CEP No SCC resource portfolio
    - Allowed selection of brownfield gas generation at reduced pricing considerations
    - Assumed all other modeling variables as described in "CEP No SCC Scenario"
12. ERP No SCC (Discounted Gas) Scenario
    - Investigated the impact of allowing brownfield gas generation to be selected would have on the Base ERP No SCC resource portfolio
    - Allowed selection of brownfield gas generation at reduced pricing considerations
    - Assumed all other modeling variables as described in "Base ERP No SCC Scenario"

Environmental Scenarios:

13. CEP 2040 Emissions Target Scenario
    - Investigated the impact that additional emissions targets would have on the CEP resource portfolio
    - Required 90% CO_2 emissions reduction by 2035, 95% reduction by 2040, and 98% reduction by 2048
    - Assumed all other modeling variables as described in "CEP Scenario"
14. CEP No SCC 2040 Emissions Target Scenario

- Investigated the impact of removing SCC and SCM in conjunction with additional emission targets would have on the CEP resource portfolio
- Required 90% CO_2 emissions reduction by 2035, 95% reduction by 2040, and 98% reduction by 2048
- Removed the SCC and SCM assumptions
- Assumed all other modeling variables as described in "CEP Scenario"

The two fundamental scenarios that were evaluated are Base ERP and Clean Energy Plan. These scenarios allowed for various sensitivities to be analyzed around their individual assumptions. Different scenarios change the assumptions that are likely to influence the size, type, and timing of resource additions and investigate their resultant impact. Modeling the scenarios evaluates the risk exposure to Black Hills because of these future uncertainties. Tables 8-3 and 8-4 summarize the assumptions used for each scenario.

Table 8-3
Fundamental Scenario Characteristics Summary

Characteristic	Base ERP	CEP
Scenario Description	Base Energy Resource Plan without Emissions Constraint	Clean Energy Plan with 80% reduction of 2005 baseline CO_2 emissions by 2030 and 100% clean energy (absolute zero) by 2050
Load Growth	Base	Base
Electric Vehicle	None	None
Building Electrification	None	None
Electric Price	Base	Base
Gas Price	Base	Base
Clean Fuels (RNG) Price	None	Base
Social Cost of Carbon Adder	Yes	Yes
Methane Cost Adder	Yes	Yes
Emissions Targets	None	Yes
Model	PLEXOS LT/ST	PLEXOS LT/ST

Table 8-4
Scenario Characteristics Summary

Scenario Type	Fundamental/Core	Core	Fundamental/Core	Core	Standard	Standard	Standard	Standard	Standard	Gas Alternative	Gas Alternative	Gas Alternative	Environ-mental	Environ-mental
Scenario	Base ERP	Base ERP No SCC	CEP	CEP No SCC	CEP Increased Electri-fication	CEP Low Load	CEP High Load	CEP Low Gas	CEP High Gas	CEP No Gas Builds	CEP No SCC (Discounted Gas)	Base ERP No SCC (Discounted Gas)	CEP 2040 Emissions Target	CEP No SCC 2040 Emissions Target
Description	Base Energy Resource Plan without emissions constraints	Base ERP scenario without SCC or SCM	Clean Energy Plan with 80% reduction of 2005 baseline CO2 emissions by 2030 and 100% clean energy (absolute zero) by 2050	CEP scenario without SCC or SCM	CEP scenario with additional load growth from electri-fication	CEP scenario with low load growth forecast	CEP scenario with high load growth forecast	CEP scenario with low fuel price forecast	CEP scenario with high fuel price forecast	CEP scenario without gas resources available for selection	CEP scenario with brownfield gas generation option and without SCC or SCM	Base ERP scenario with brownfield gas generation option and without SCC or SCM	CEP scenario with interim emissions reduction targets: 90% by 2035, 95% by 2040, 98% by 2048	CEP scenario with interim emissions reduction targets: 90% by 2035, 95% by 2040, 98% by 2048 and without SCC or SCM
Core Scenario	Base ERP	Base ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP	CEP	CEP	Base ERP	CEP	CEP
Load Growth	Base	Base	Base	Base	Base	Low	High	Base	Base	Base	Base	Base	Base	Base
Electric Vehicle	None	None	None	None	Yes	None	None	None	None	None	None	None	None	None
Building Electrification	None	None	None	None	Yes	None	None	None	None	None	None	None	None	None
Electric Price	Base	Base	Base	Base	Base	Base	Base	Low	High	Base	Base	Base	Base	Base
Gas Price	Base	Base	Base	Base	Base	Base	Base	Low	High	Base	Base	Base	Base	Base
RNG Price	None	None	Base	Base	Base	Base	Base	Base	Base	Base	Base	None	Base	Base
Social Cost of Carbon Adder	Yes	No	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	No
Methane Cost Adder	Yes	No	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	No
Emissions Targets	None	None	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	None	Yes	Yes
Model	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST	PLEXOS LT/ST

8.6 Scenario Portfolio Analysis

Scenario analyses were conducted during which the Capacity Expansion model analyzed fourteen scenarios to derive candidate resource portfolios. The scenarios include variables that would create the largest impact on cost variability and risk to result in unique resource portfolios. The resultant candidate resource portfolios developed for BHCOE are provided below.

8.6.1 Discussion of Scenarios

The ERP first examined a base plan (Scenario 1) that describes the costs and benefits of the new resources required to meet load needs during the entire Planning Period. The ERP refers to this as the Base ERP Plan. Scenario 2 is like Scenario 1 in all aspects, except for the exclusion of the social cost of carbon. While the base ERP is normally the plan that minimizes PVRR, in this case the ERP without the social cost of carbon is the plan that minimizes the PVRR since there is less incentive to build renewable resources.

The CEP Scenarios 3 and 4 change Scenarios 1 and 2 by requiring emission reduction targets to be met. Since more renewable resources are required to achieve these targets, these two scenarios show the increased financial requirements necessary to meet environmental goals set by the state legislature.

Scenarios 5 through 9 change the assumptions that are likely to influence the size, type, and timing of resource addition, and investigate their resultant impact. Modeling these scenarios evaluates the risk exposure to the Company because of these future uncertainties.

Scenario 10 changes the resources available for selection by removing all new gas units. This subset of the available resources, including renewables, storage and SMR, provides a look at the potential future resource mix as the Company continues to shrink its emissions profile in alignment with legislated state goals without continued economic reliance on new natural gas resources.

Scenarios 11 and 12 also change the resources available for selection by adding an additional low-cost gas resource as an option. These scenarios highlight alternative resource buildouts centered on discounted gas.

Scenarios 13 and 14 provide a look at changes focused on additional environmental considerations. These two scenarios add more emission reduction targets to those required by the CEP in the intermediate years between 2030 and 2050. Due to the added emission reductions targets, more renewable resources are necessary to build, which provides insight into possible future costs that come with more robust renewable energy buildouts.

8.6.2 Fundamental and Core Scenario Portfolios

The resource portfolios for the four core scenarios add varying amounts of gas, wind, solar, and storage during the RAP. Natural gas additions support the wind, solar, and storage additions as depicted in each scenario by providing dispatchable capacity to help maintain system reliability. Capacity Expansion modeling results for these scenarios are shown in Table 8-5.

Table 8-5
Optimal Expansion Plans – Core Scenario Analysis

Year	1. Base ERP	2. ERP No SCC	3. CEP	4. CEP No SCC
2029	154 MW Wind	54 MW RICE	154 MW Wind	18 MW RICE 78 MW Wind
2030	36 MW RICE	18 MW RICE 7 MW Wind	36 MW RICE	36 MW RICE
2031		3 MW BESS		
2032	72 MW RICE 26 MW Wind 10 MW Solar 200 MW BESS	90 MW RICE 168 MW BESS	72 MW RICE 6 MW Wind 41 MW Solar 205 MW BESS	72 MW RICE 20 MW Wind 200 MW BESS
2033	11 MW BESS	25 MW BESS	48 MW BESS	37 MW BESS
2034	18 MW RICE	9 MW Wind		7 MW Wind
2035		3 MW Wind	7 MW Solar	4 MW Wind
2036		2 MW Wind	10 MW Solar	3 MW Wind
2037		14 MW Wind	11 MW Wind 24 MW Solar	25 MW Wind
2038		4 MW Wind	16 MW Wind	23 MW Wind
2039		5 MW Wind	11 MW Solar	3 MW Solar
2040	1 MW Wind 5 MW Solar	3 MW Wind	14 MW Solar	14 MW Solar
2041	12 MW Wind 69 MW Solar	30 MW Wind	18 MW RICE	30 MW Wind 17 MW Solar
2042	24 MW Wind	5 MW Wind	61 MW Wind	61 MW Wind
2043	18 MW RICE	18 MW RICE 43 MW Solar	123 MW Solar	189 MW Solar
2044	78 MW Solar	3 MW Wind 42 MW Solar	65 MW Solar	64 MW Solar
2045	31 MW Solar	16 MW Solar	60 MW Wind 11 MW Solar	60 MW Wind 13 MW Solar
2046	18 MW RICE	18 MW RICE	27 MW Wind	28 MW Wind
2047	108 MW RICE	126 MW RICE	90 MW RICE 87 MW Wind	90 MW RICE 84 MW Wind 5 MW Solar 15 MW BESS
2048			13 MW Wind	13 MW Wind
2049	4 MW BESS		44 MW Wind 7 MW Solar	42 MW Wind 5 MW Solar
2050	5 MW BESS	4 MW BESS		

8.6.3 Standard Scenario Portfolios

The standard scenarios investigate the impacts increased load growth, lower than expected load growth, and uncertain fuel pricing can have on resource buildout. Capacity Expansion modeling results for these scenarios are shown in Table 8-6.

Table 8-6
Optimal Expansion Plans – Standard Scenario Analysis

Year	5. CEP Increased Electrification	6. CEP Low Load	7. CEP High Load	8. CEP Low Gas	9. CEP High Gas
2029	18 MW RICE 226 MW Wind	92 MW Wind	18 MW RICE 137 MW Wind	154 MW Wind	154 MW Wind
2030	88 MW BESS	65 MW Wind 15 MW BESS	36 MW RICE	36 MW RICE	18 MW RICE 60 MW Wind
2031	9 MW Wind 21 MW BESS		4 MW BESS		3 MW BESS
2032	162 MW RICE 33 MW Wind 121 MW Solar 157 MW BESS	90 MW RICE 19 MW Solar 184 MW BESS	72 MW RICE 28 MW Wind 46 MW Solar 217 MW BESS	72 MW RICE 5 MW Wind 222 MW BESS	72 MW RICE 77 MW Solar 216 MW BESS
2033	153 MW BESS	24 MW BESS	29 MW BESS	12 MW BESS	38 MW BESS
2034	18 MW RICE 48 MW Solar		18 MW RICE	18 MW RICE	20 MW Solar
2035	18 MW RICE 20 MW Solar				3 MW Wind 3 MW Solar
2036	18 MW RICE 10 MW Wind				10 MW Solar
2037	18 MW RICE 25 MW Wind 33 MW Solar	12 MW Wind	7 MW Wind 4 MW Solar		18 MW RICE
2038	36 MW RICE	20 MW Wind	30 MW Wind	14 MW Wind	3 MW Wind
2039	18 MW RICE		35 MW Solar		
2040	18 MW RICE		34 MW Solar		
2041	18 MW RICE 35 MW Wind 15 MW Solar	8 MW Wind 21 MW Solar	18 MW RICE	11 MW Wind 50 MW Solar	1 MW Solar
2042	18 MW RICE 61 MW Wind 34 MW Solar	61 MW Wind	61 MW Wind	61 MW Wind	61 MW Wind
2043	18 MW RICE 40 MW Wind 157 MW Solar	104 MW Solar	179 MW Solar	184 MW Solar	138 MW Solar
2044	18 MW RICE 69 MW Wind 7 MW Solar	69 MW Solar	32 MW Wind 14 MW Solar	1 MW Wind 65 MW Solar	18 MW RICE
2045	18 MW RICE 74 MW Wind 7 MW Solar	60 MW Wind	73 MW Wind	67 MW Wind	60 MW Wind
2046	44 MW Wind 19 MW Solar 79 MW BESS	18 MW Wind 11 MW Solar	25 MW Wind 6 MW Solar	29 MW Wind	40 MW Solar
2047	126 MW RICE 69 MW Wind	90 MW RICE 95 MW Wind 19 MW Solar	108 MW RICE 29 MW Wind 9 MW Solar	90 MW RICE 85 MW Wind 20 MW BESS	90 MW RICE 74 MW Wind 21 MW Solar
2048	18 MW RICE 81 MW Wind 9 MW BESS		50 MW Wind	13 MW Wind	13 MW Wind
2049	18 MW RICE 176 MW Wind 48 MW BESS	25 MW Wind	69 MW Wind 40 MW Solar 7 MW BESS	38 MW Wind 15 MW Solar	47 MW Wind 3 MW Solar
2050	18 MW RICE				

8.6.4 Gas Alternative Scenario Portfolios

The resource portfolios for gas alternative scenarios add unique resources that other scenarios do not, including a nuclear SMR and brownfield gas generation. Gas resource availability was removed for Scenario 10 and brownfield gas generation were available in Scenarios 11 and 12. Capacity Expansion modeling results for these scenarios are shown in Table 8-7.

Table 8-7
Optimal Expansion Plans – Gas Alternatives Analysis

Year	10. CEP No Gas Builds	11. CEP No SCC (Discounted Gas)	12. ERP No SCC (Discounted Gas)
2029	100 MW Wind 14 MW BESS	57 MW Wind 27 MW BESS	49 MW BESS
2030	75 MW Wind 38 MW Solar 11 MW BESS	41 MW Wind 23 MW BESS	37 MW BESS
2031	3 MW BESS	3 MW BESS	3 MW BESS
2032	60 MW Nuclear 582 MW BESS	150 MW Gas Recontract 76 MW BESS	200 MW Gas Recontract
2033	117 MW BESS	57 MW BESS	40 MW BESS
2034			
2035			
2036	8 MW Solar	3 MW Wind	
2037	41 MW Solar	15 MW Wind	
2038	13 MW Solar	30 MW Wind	4 MW Wind
2039	12 MW Solar	8 MW Solar	4 MW Wind
2040	11 MW Solar	14 MW Solar	4 MW Wind
2041	70 MW Solar	49 MW Solar	24 MW Wind
2042	12 MW Solar	61 MW Wind	4 MW Wind
2043	195 MW Solar	14 MW Wind 193 MW Solar	18 MW RICE 68 MW Solar
2044	11 MW Wind 60 MW Solar	38 MW Wind 1 MW Solar	3 MW Wind 2 MW Solar
2045	12 MW Wind	69 MW Wind	31 MW Solar
2046	20 MW Wind 18 MW Solar	32 MW Wind	3 MW Wind 51 MW BESS
2047	13 MW Wind 753 MW Solar 290 MW BESS	72 MW RICE 11 MW Wind 16 MW Solar 110 MW BESS	126 MW RICE 10 MW BESS
2048	10 MW Solar 7 MW BESS	33 MW Wind	3 MW BESS
2049	13 MW Solar 8 MW BESS	45 MW Wind 64 MW Solar	3 MW BESS
2050			4 MW BESS

8.6.5 Environmental Scenario Portfolios

Two additional environmental portfolios were developed to show the effects aggressive emissions reductions targets would have on resource buildout. Additional to the CEP requirements of 80% CO_2 emission reduction by 2030 and 100% emission reduction by 2050, the two environmental scenarios also have constraints to reduce CO_2 emissions to 90% by 2035, 95% by 2040, and 98% by 2048 when compared to a 2005 baseline. Capacity Expansion modeling results for these scenarios are shown in Table 8-8.

Table 8-8
Optimal Expansion Plans – Environmental Scenario Analysis

Year	13. CEP 2040 Emissions Target	14. CEP No SCC 2040 Emissions Target
2029	154 MW Wind	36 MW RICE 11 MW Wind 4 MW BESS
2030	36 MW RICE	105 MW Wind
2031		2 MW BESS
2032	72 MW RICE 11 MW Wind 32 MW Solar 196 MW BESS	72 MW RICE 37 MW Wind 222 MW BESS
2033	39 MW BESS	3 MW Wind 10 MW BESS
2034	10 MW Solar	14 MW Wind 36 MW Solar
2035	11 MW Solar	13 MW Solar
2036	19 MW Solar	22 MW Solar
2037	21 MW Wind	17 MW Wind 2 MW Solar
2038	30 MW Wind 9 MW Solar	30 MW Wind 13 MW Solar
2039	19 MW Wind	19 MW Wind
2040	22 MW Wind	22 MW Wind
2041	3 MW Wind 18 MW Solar	5 MW Wind 16 MW Solar
2042	61 MW Wind	61 MW Wind
2043	182 MW Solar	182 MW Solar
2044	37 MW Wind 13 MW Solar	27 MW Wind 32 MW Solar
2045	60 MW Wind 14 MW Solar	67 MW Wind
2046	29 MW Wind	29 MW Wind
2047	108 MW RICE 3 MW Wind 24 MW Solar	108 MW RICE 20 MW Wind 16 MW Solar
2048	14 MW Wind	
2049	7 MW BESS	4 MW BESS
2050	8 MW BESS	8 MW BESS

8.6.6 Present Value Revenue Requirements

Production cost modeling was performed on the fourteen candidate resource portfolios established by the Capacity Expansion modeling to calculate the Present Value Revenue Requirements (PVRR) for each portfolio. These PVRRs were calculated for each of the scenarios using the scenario assumptions as described above. The PVRRs for the scenario analysis during the RAP and Planning Period are shown in Figure 8-1 and Figure 8-2, respectively, where the grey shaded portions represent the social cost of carbon.

Figure 8-1
Base ERP and Scenarios – Deterministic RAP PVRRs (2026-2032)
7 Year PVRR ($MM)

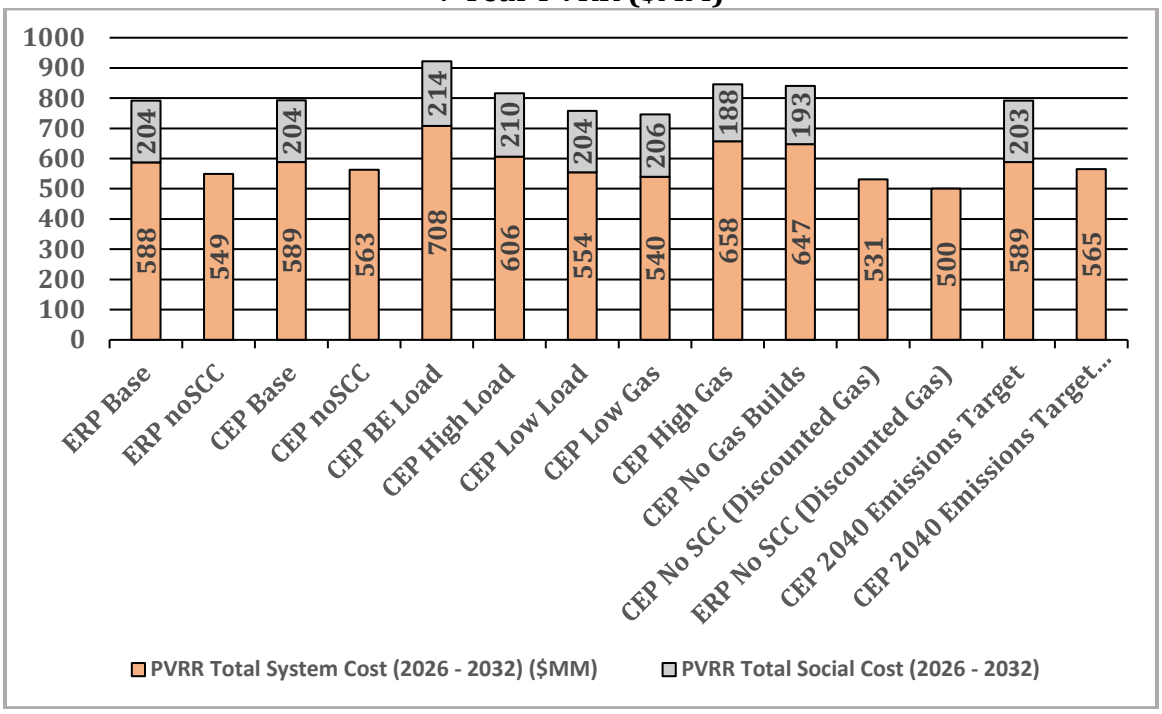
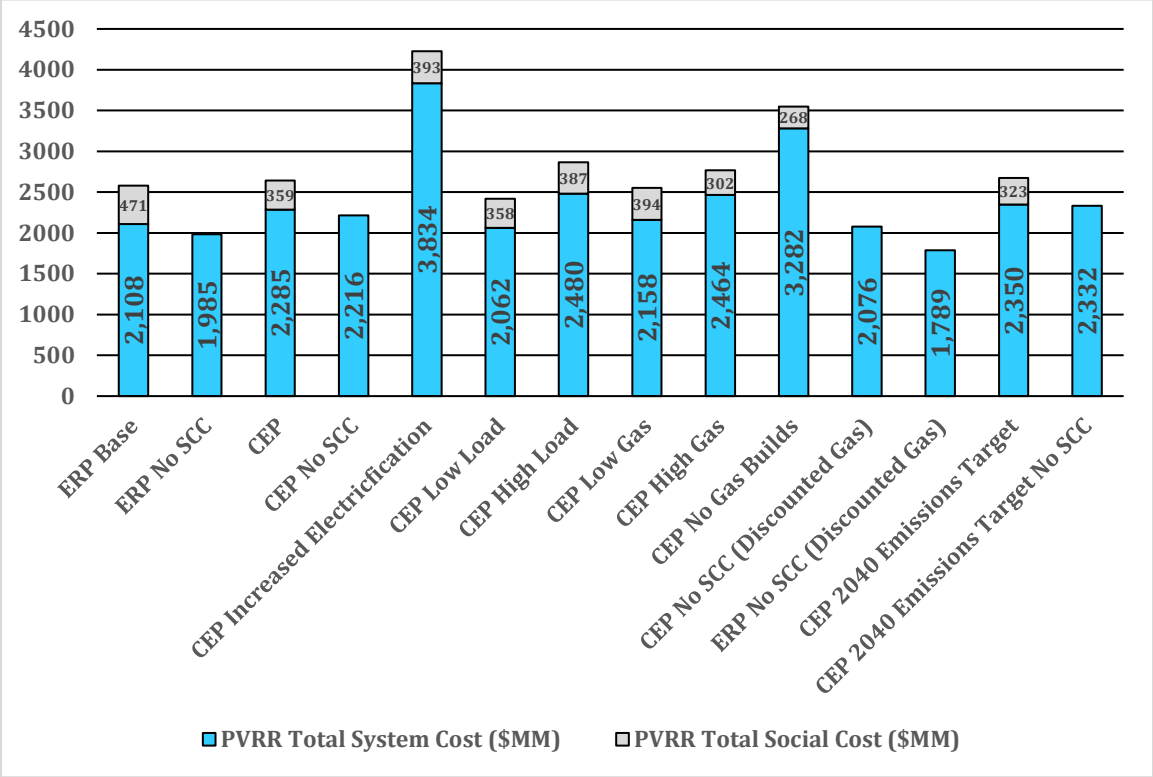


Figure 8-2
Base ERP and Scenarios – Deterministic PVRRs (2026-2050)
25 Year PVRR ($MM)



The PVRRs in the figures above provide a snapshot of portfolio costs under a variety of scenarios. Based on the RAP PVRR analysis, the least-cost portfolio is the Base ERP No SCC scenario; however, it achieves only a 76 percent reduction in greenhouse gas emissions by 2030. During the RAP, the CEP and Base ERP scenarios have similar portfolios. The SCC scenarios inherently have higher costs than the No SCC scenarios due to the inclusion of the additional social costs. The inclusion of these social costs, as well as the modeling requirement to meet the CEP's 80 percent emissions reduction, results in a portfolio buildout that is different than the No SCC scenarios. The modeling completed for the No SCC scenarios did not have social costs to further incentivize carbon reductions, and therefore the Total System Cost in the graph above reflects the cost of a different portfolio mix than the SCC scenarios. The PVRR for the Increased Electrification scenario is significantly higher than the other portfolios, indicating increased customer costs.

8.6.7 Discussion of Scenario Portfolio Analysis

A common theme from all the resulting portfolios in the resource acquisition period is the selection of up to 200 MW natural gas, up to 200 MW battery energy storage, and up to 200 MW wind resources. Natural gas resources provide firm, dispatchable capacity and energy to continue to enhance the reliability of the system, while providing support to the variable resources in the portfolio. Similarly, battery energy storage offers capacity to quickly support grid responsiveness and complements renewable energy integration. Wind resources provide the renewable energy needed to continue to move toward achieving reduced emissions goals.

The Base ERP and CEP scenarios have very similar buildouts, resulting from the inclusion of the social cost of carbon which incentivizes additional wind resources to overcome the social costs constraining the modeled portfolios. Both portfolios meet 85% emissions reduction by 2030, overachieving the 80% requirement. This is accompanied by an increased PVRR as compared to other lower cost alternatives.

The ERP No SCC and CEP No SCC scenarios remove the social cost of carbon constraints. The ERP No SCC is the least cost scenario among the core scenarios, building only enough economic gas and storage with traces of wind to meet the forecasted demand. During the RAP, this results in only 340 MW of additional resources needed, offering cost savings to customers, but falls short of the 80% emissions reduction by several percentage points by 2030. The CEP No SCC provides a nice balance of being able to meet the 80% emissions reduction, achieving exactly that, and keeping costs low. The CEP No SCC builds 126 MW natural gas, 200 MW storage, and 98 MW wind resources in the RAP, striking yet another balance between firm, dispatchable resources and renewable energy, achieving both reliability and emissions reductions simultaneously. Comparatively of note, while the ERP Base achieves higher emissions reductions at a lower PVRR during the 25-year planning period, the CEP no SCC scenario still achieves the emissions reduction goals at a lower PVRR during the 7-year RAP, where the Company will be soliciting bids during the ERP Phase II, resulting in a better near-term resource mix.

The Gas Alternative Scenarios offer useful insight depending on the types of bids that could be received in the Phase II RFP. First, the CEP No Gas Builds Scenario is named so because it removes the ability to procure economic gas resources, only allowing renewable, storage, and SMR resources to fill capacity deficits. This results in some of the highest PVRRs, only second to the CEP Beneficial Electrification scenario. The CEP No Gas Builds Scenario results in large amounts of storage, renewables, and SMR resources during the RAP, significantly overachieving the emissions reduction at 87% by 2030. More importantly, the true remaining Gas Alternative Scenarios (Scenarios 11 and 12), could offer customer savings if a brownfield gas resource was offered at a reduced price as compared to a new build. Both scenarios build up to 200 MW natural gas, supplemented with up to 129 MW of storage. The ERP No SCC

(Discounted Gas) Scenario is the least cost scenario among all scenarios, but only achieves 77% emissions reductions. The CEP No SCC (Discounted Gas) Scenario achieves 82% emissions reductions, while having the second lowest PVRR during RAP.

The Standard Scenarios (Scenarios 5-9) investigate the impacts increased load growth, lower than expected load growth, and uncertain fuel pricing can have on resource buildout. During the RAP, the portfolio builds fluctuate, around 200 MW each for gas, storage, and renewable resources, providing intuitive PVRR results. This illustrates that in uncertain load and commodity pricing conditions, the general resource portfolio mix identified in the Core and Gas Alternative Scenarios would serve well under these conditions.

The Environmental Scenarios (Scenarios 13 and 14) provide a potential outlook for how the portfolio would change to meet additional environmental considerations. Due to the added emission reductions targets, more renewable resources are necessary to build, which provides increased long-term PVRR costs that produce more robust renewable energy buildouts.

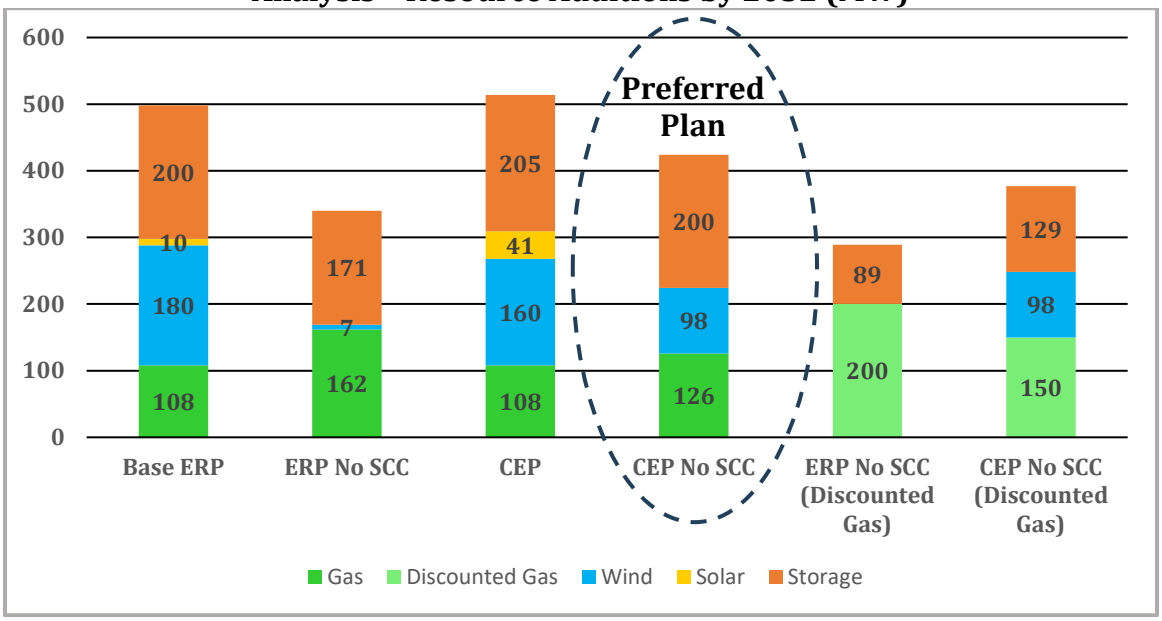
The scenario results are further highlighted in Table 8-9.

Table 8-9
RAP Resource Portfolios

Scenario Type	Fundamental & Core		Core		Standard					Gas Alternatives			Environmental	
Scenario	ERP Base	CEP	ERP Base No SCC	CEP No SCC (Preferred Plan)	CEP Increased Electrification	CEP High Load	CEP Low Load	CEP Low Gas	CEP High Gas	CEP No Gas Builds	CEP No SCC (Discounted Gas)	ERP No SCC (Discounted Gas)	CEP 2040	CEP No SCC 2040
Gas Replacement											150	200		
Gas	108	108	162	126	180	126	90	108	90				108	108
Storage	200	205	171	200	266	221	199	222	219	610	129	89	196	228
Wind	180	160	7	98	268	165	157	159	213	175	98		171	153
Solar	10	41			121	46	19		77	38			32	
Nuclear										60				
2030 CO_2 Emissions Reduction	85%	85%	76%	80%	85%	83%	85%	85%	88%	87%	82%	77%	85%	82%
PVRR RAP System Cost (2026-2032) ($MM)	588	589	549	563	708	606	554	540	658	647	531	500	589	565
PVRR Total System Cost (2026-2050) ($MM)	2,108	2,285	1,985	2,216	3,834	2,480	2,062	2,158	2,464	3,282	2,076	1,789	2,350	2,332

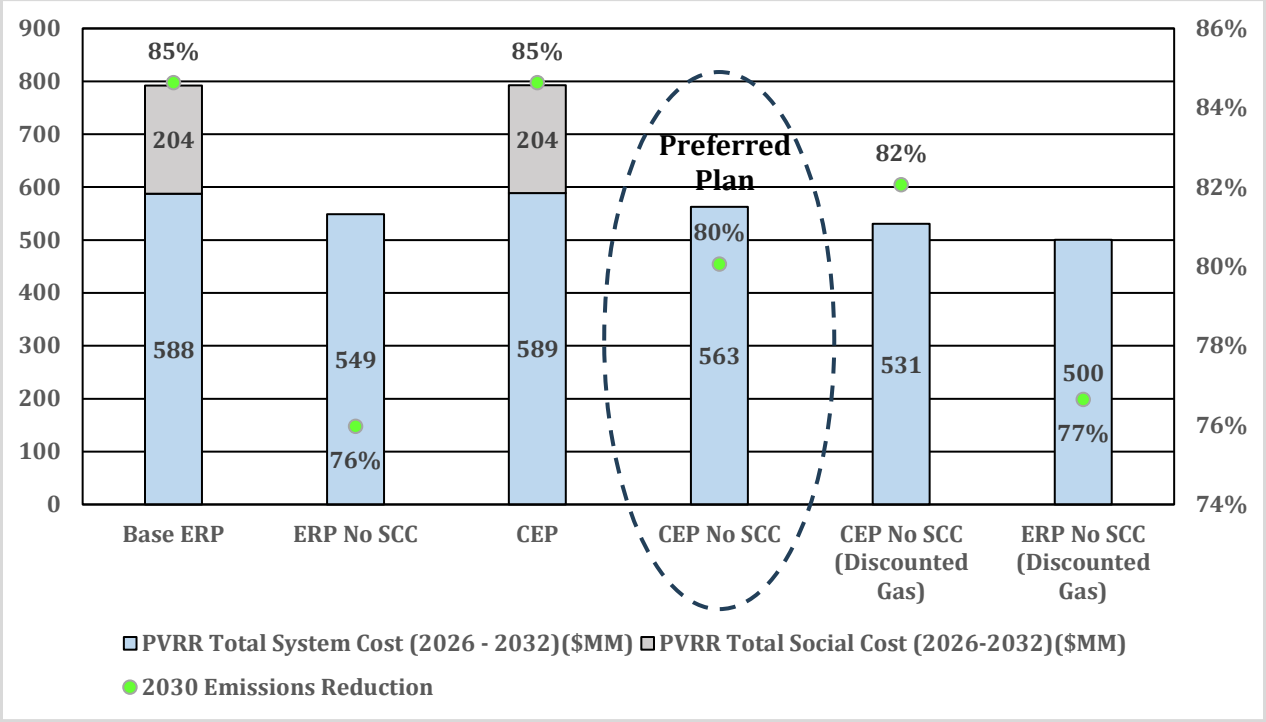
A closer comparison of the resource portfolios shows that the CEP and ERP scenarios add varying amounts of gas, wind, solar, and storage resources during the RAP. Capacity Expansion modeling results for the Core and Gas Alternative CEP and ERP scenarios, both with and without the SCC, are provided in Figure 8-3.

Figure 8-3
Optimal Expansion Plans – Core and Gas Alternative CEP and ERP Scenario Analysis – Resource Additions by 2032 (MW)



Emissions reductions achieved by 2030 and RAP PVRRs for the Core and Gas Alternative CEP and ERP scenarios, with and without the SCC, are provided in Figure 8-4.

Figure 8-4
Optimal Expansion Plans – Core and Gas Alternative CEP and ERP Scenario Analysis – Emissions Reductions by 2030 & Deterministic PVRRs by 2032 (MW)



In summary, the resource acquisition period portfolios consistently identified a combination of up to 200 MW of natural gas, up to 200 MW of battery energy storage, and up to 200 MW of wind resources as the preferred resource mix. This combination reflects the complementary benefits of each technology: natural gas provides firm, dispatchable capacity and energy that strengthens system reliability and supports variable resources; battery energy storage enhances grid responsiveness and facilitates renewable energy integration; and wind resources contribute the renewable energy necessary to advance emissions reduction objectives. Together, these resources create a balanced portfolio that supports reliability, operational flexibility, and long-term sustainability goals, which are best addressed through the Company's Preferred Plan.

8.7 Preferred Plan

As a result of the load and resource balance, capacity expansion, production cost modeling, and retail rate impact evaluations, Black Hills is recommending the Clean Energy Plan No SCC scenario as the Preferred Plan, as it cost effectively achieves Colorado's state policy objectives, alleviates capacity deficit needs, and maintains system reliability and dispatchability. The Preferred Plan's RAP portfolio and PVRR is shown in Figure 8-4 and Table 8-10. The Preferred Plan is estimated to achieve 80

percent emissions reductions by 2030. This Plan allows the Company to meet the CEP requirements and policy objectives. The Company has prepared Air Pollution Control Division Verification Workbooks in accordance with their guidelines, as shown in Appendix L.

The Clean Energy Plan No SCC is the ideal choice for the Preferred Plan because it delivers a low cost to customers, while addressing emission constraints and resource adequacy needs. Due to the forecasted load growth and necessary planning reserves, in conjunction with not being able to build the solar resource identified in the last ERP, there is still a capacity shortfall and inability to meet emissions reductions requirements. Where renewable resources help alleviate emission concerns, storage and natural gas units offer quick and reliable, dispatchable energy. As noted in the Gas Alternative Scenarios, potential brownfield gas generation resources would offer additional customer savings as well if bid into the Company's Phase II RFP.

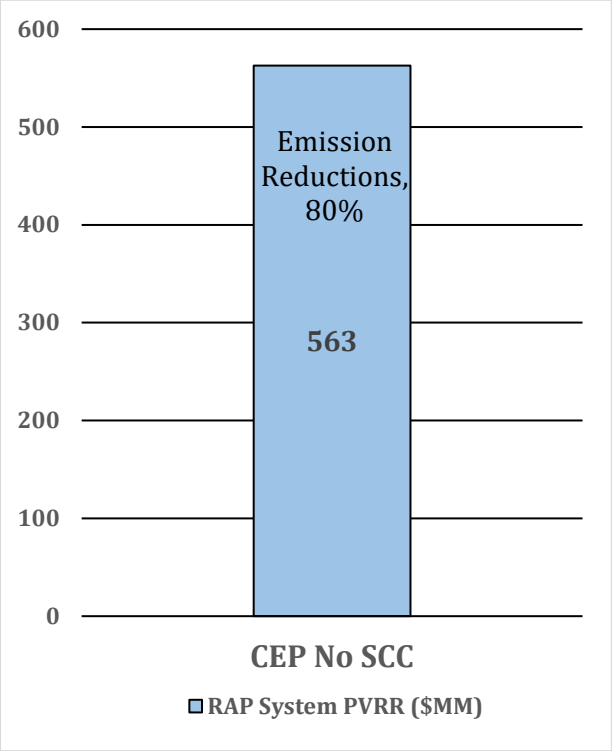
Beyond the RAP, Black Hills' load and resource balance continues to show a capacity deficit which expands as additional generation resources expires. The modeling identified an optimal portfolio to replace these expiring resources. However, based on current Commission electric resource planning rules, the Company will be required to complete at least one resource plan prior to considering the appropriate replacement capacity.

Black Hills' Preferred Plan recommends that the Company engages in a Phase II competitive solicitation to acquire about 424 MW of gas, wind, and storage resources by 2032. The modeling supports this recommendation in the CEP No SCC scenario which identifies a need for 126 MW of gas, 98 MW of wind, and 200 MW of storage by 2032. The exact capacity mix of these resources will be further refined in the Phase II analysis of this proceeding, where up to 200 MW of each resource type will be allowed to be bid in. This solicitation and subsequent analysis will allow the Company to determine if Clean Energy Plan resources can be acquired at a cost that will meet the requirements of the retail rate impact and CEP legislation such that Black Hills will comply with the 80 percent emissions reduction by 2030.

The planning assumptions used in this Plan will underline the evaluation of proposals received in response to a Company solicitation in Phase II of this Plan's proceeding. The Company has included a list of General Planning Assumptions in Appendix A that were used in the ERP modeling and will be used in the solicitation process. These assumptions represent "base case" assumptions. Sensitivity analysis will be performed in which certain of these assumptions are altered in accordance with any Commission directives. The Company has indicated in the General Planning Assumptions table in Appendix A those assumptions that will be updated for the evaluation of proposals.

Table 8-10 & Figure 8-5
Preferred Plan Scenario – RAP Portfolio & Deterministic PVRR (2026-2032) – 7 Year PVRR ($MM)

Year	CEP No SCC
2026	
2027	
2028	
2029	18 MW RICE 78 MW Wind
2030	36 MW RICE
2031	
2032	72 MW RICE 20 MW Wind 200 MW BESS



9.0 Contingency Plan

Rule 3609(c) requires the utility to develop contingency plans for the RAP and to provide, under seal, a description of its proposed contingency plans for: (1) the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to Rule 3610; or (2) the acquisition of replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under Rule 3617.[63]

Black Hills understands that matching electric generation with customer demand will not always proceed according to plan. Problems could arise as a result of delay in the in-service dates of new generation facilities, contract negotiations with suppliers can break down, and unanticipated increases in the customer demand can materialize. While it is impossible to anticipate everything that can occur in the resource acquisition process, the Company can anticipate the more common contingencies and develop plans to address them. This section identifies what the Company believes to be the most likely situation it might face in the resource acquisition process and identifies contingency alternatives available to Black Hills. This contingency plan is developed recognizing that the generation resources proposed in the Plan will be developed through an all-source competitive solicitation. With that background, the contingency plan set forth below will focus on events or situations that create the potential for a capacity shortfall if corrective action is not taken.

9.1 Contingency Events

The contingency events that are more relevant and probable to occur include, but are not limited to:

1. Higher than anticipated electric demand
2. Limited or no availability of seasonal firm market power
3. Extremely high seasonal firm market power prices
4. Project development delays or cancellations

9.2 Contingency Options

Options available, either individually or in combination, to the Company in case one of the contingency events occurs include:

1. Purchase short-term capacity from off-system or existing generation supplies
2. Arrange for temporary generation

[63] Black Hills is not filing contingency plans under seal because it has set forth its non-confidential contingency plan options below. To the extent this would require a waiver of Rule 3609(c), such a waiver is hereby requested.

3. Develop and implement interim load management/customer generation plans
4. Attempt to increase DSM
5. Accelerate in-service dates of resources

9.3 Critical Factors

Two critical factors dictate whether a corrective action provides a viable solution for a particular contingency event. These factors are:

1. The magnitude of the potential resource shortfall, and
2. The timing associated with the potential capacity shortfall—both the lead-time to the contingency and the duration of the event

The magnitude of an anticipated capacity shortfall dictates the available options that Black Hills can pursue. For example, a capacity shortfall of 5 – 50 MW might be addressed through contracting short-term purchases from existing generation (if available) in the market. Short-term capacity purchases would likely be ineffective in addressing a higher MW, long-term shortfall.

The timing of an anticipated capacity shortfall dictates the number of options available for the Company to use. Duration of the shortfall and when it is expected to occur are critical factors in responding to the contingency. Capacity needed in the short term could be addressed through short-term purchases if available. Larger capacity needs that might occur several years in the future could be addressed through a variety of actions, including new construction.

9.4 Corrective Actions

In the event of a capacity shortfall situation, the appropriate course of action will depend on the specifics of the shortfall itself. As discussed above, the details of the shortfall will help guide the corrective action, but Black Hills will always need to apply its business judgment when deciding on the corrective action. Listed below are possible solutions in the event a contingency event occurs.

1. Short-Term capacity purchases, if available. This could be used when there is not enough time to use one of the following corrective actions.
2. Accelerate in-service date of resources. If the contingency becomes known far enough in advance, certain resource timing can be accelerated to account for the higher demand.
3. Install temporary generation. This measure can be implemented with less lead time than the installation of new permanent generation. This option is well suited to cover a generation project or transmission delay that may last a year or possibly two.

4. Develop and implement interim load management or customer generation programs. Similar to the installation of temporary generation, the measure can be implemented within a relatively short lead time and is well suited to address short-term resource delays.
5. Temporarily operate on reduced reserve margin. If the contingency became known too late to add new resources in time and insufficient short-term purchases were available to cover the contingency, Black Hills could operate with a reduced planning reserve margin but with the required operating reserve margin for a summer season until one or a combination of other corrective actions could be put into service.

Black Hills and its sister electric utilities have experience with many of these situations and can draw upon a wide range of resources, experience, and capabilities in order to respond in the most appropriate way to contingencies that might develop during the RAP.

10.0 RFPs and Model Contracts

As required by Rule 3604(i), the Company is filing in Appendix N of this Plan the proposed RFP(s) and model contracts the Company intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process pursuant to Rule 3616.

11.0 Confidential and Highly Confidential Information

As required by Rule 3604(j), the Company must provide a list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The utility shall also list the information that it will provide to owners or developers of a potential resource under Rules 3613(a) and (b). The utility shall further explicitly list the protections it proposes for bid prices, other bid details, information concerning a new resource that the utility proposes to build and own as a rate base investment, other modeling inputs and assumptions, and the results of bid evaluation and selection. The protections sought by the utility for these items shall be specified in the motion(s) submitted under Rule 3603(b). For good cause shown, the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under Rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

11.1 Public Information

The following information that is relevant to the Plan is, or will be, public information as the result of the Company filing the information in Phase I or Phase II of the Plan or as the result of a prior filing with the Commission, the State of Colorado or with federal agencies:

11.1.1 Company Information

- Annual Sales
- Annual Revenue
- Resource Need for RAP
- RES Status
- RESA
    - Balance
    - Forecast
- Peak Demand and Energy Forecast
    - Annual / Monthly Peak Demand
    - Annual / Monthly Total Energy Demand
- Total DSM Costs

11.1.2 Purchased Generation Resource Information

- Capacity
- Contract Duration
- Contract Modification Terms

11.1.3 Model Input Data

- Depreciation and Amortization Expense
- Capacity
- Monthly On/Off Peak Market Prices
- Fuel Costs
- Average Heat Rate
- Fuel Type
- Expected Retirement Date
- Contract Duration
- Contract Modification Terms
- Inflation/Escalation Rate
- Federal Tax Rate
- State Tax Rate
- Discount Rate
- Weighted-Average Cost of Capital
- Wind Integration Costs
- Solar Integration Costs
- DSM Forecast
- Reserve Margin Requirements
- In-Service Dates
- Unit Capacities
- PPA In-service Dates
- PPA Retirement Dates
- PPA Capacities
- Market Emission Assumptions
- SO_2 Pricing
- NO_x Pricing
- CO_2 Pricing
- Unit Emission Rates
    - SO_2
    - NO_x
    - CO_2
    - Mercury
- PPA Emission Rates
    - CO_2
    - SO_2
    - NO_x
    - Mercury
- Generic Resources
    - Name Plate Capacity
    - Summer Peak Capacity
    - Capital Costs

  - Book Life
  - Fixed O&M
  - Variable O&M
  - Heat Rate Curves
  - Forced Outage Rates
  - Typical Annual Maintenance Requirements
  - CO_2 Emission Rate
  - NO_x Emission Rate
  - SO_2 Emission Rate
  - PPA Pricing if applicable
- Generic Renewable Resources
  - Capital Costs
  - Fixed O&M
  - Variable O&M

11.1.4 Modeling Output Data

- Annual System Capacity Obligation
- Total System Capacity
- Capacity Additions (Expansion Plans)
- Capacity Retirements
- Total Emissions by Type
- Unit Emissions by Type
- Total Fuel Consumed
- Capacity Factors
- Unit Level Generation
- Unit Level Fuel Consumed
- Fuel Cost
  - Gas Cost Projection
- Capacity
- Energy Purchased
- Cost of Energy Purchased
- Unit Level Emissions
  - NO_x
  - SO_2
  - CO_2
  - Mercury
- PPA Maximum Capacities
- PPA Summer Accredited Capacities
- PPA Accredited Capacities
- PPA Generation
- System Emissions

  - CO_2
  - SO_2
  - NO_x
  - Mercury
- PPA Emissions
  - NO_x
  - SO_2
  - CO_2
  - Mercury
- Average Cost per-kWh modeling output
- Total System Present Value of Revenue Requirements

The models developed for the Company's Plan contain thousands of data points that were used to represent the Company's system. Model inputs are not contained in files that would be easily understood or manipulated. Specific questions concerning data input will receive an informative response. Worksheets developed by the Company for provision to the modeling vendor and output worksheets can be provided.

11.2 Confidential Information

The Company will seek to protect the following proprietary information as confidential information:

11.2.1 Modeling Input Data

- Hourly Load Patterns
- Unit Level Costs
- Unit Start Up Costs and Start Up Fuel
- Unit Variable O&M
- Unit Fixed O&M
- Unit Contribution to Spinning Reserve
- PPA Capacity Pricing (subject to contractual limitations)
- PPA Energy Pricing (subject to contractual limitations)
- PPA Energy Schedules (subject to contractual limitations)
- PPA Contribution to Spinning Reserves
- Hourly Wind Patterns
- Hourly Solar Patterns

11.2.2 Modeling Output Data

- Unit Level Capacity Factors
- Unit Level Total Variable O&M
- Unit Level Fixed O&M

- Unit Start Up Costs and Start Up Fuel
- PPA Capacity Factors
- PPA Total Energy Payments (subject to contractual limitations)
- PPA Total Capacity Payments (subject to contractual limitations)

11.3 Highly Confidential Information

The Company considers the following proprietary information as highly confidential information:

- Unit Level Heat Rate and Heat Rate Curves
- Unit Detailed Maintenance Schedules
- Bid Information of any sort (from the Company and from other entities)
- Pricing and any other commercially sensitive information regarding a PPA
- Certain Modeling Files

The Company believes that disclosure of the items listed above can cause irreparable harm to the Company's trading operations, the Company's ability to solicit cost-effective resources, and, ultimately, the Company's customers. The Company will seek to limit access in accordance with the Commission's Rules, including Rule 3603(b).

12.0 Implementation of Separation Policy

The Company will implement a separation policy prior to the issuance of the Phase II competitive solicitation.

13.0 Protection of Bid Information, Modeling Inputs and Assumptions, and Bid Evaluation Results

The Company will seek to protect all bid information and bid evaluation results (including Company self-build proposals) that would reveal specific bid pricing or other bid information, as highly confidential information in accordance with the Commission's Rules, until completion of the resource acquisition process, i.e. until the last contract for a resource that meets a portion of the Plan resource need is signed. In accordance with Commission Rule 3613(k), upon completion of the resource acquisition process, the Company will post on its website the following bid information:

- Bidder Name
- Bid Price (Utility Cost for Utility–Owned Bid Proposals)
- Generation Technology Type
- Size of Facility
- Contract Duration (Expected Useful Life of Utility Resource)
- Purchase Option Details as relevant

In accordance with the ERP Rule 3613(j), within 14 months after completion of the resource acquisition process, the Company will make public confidential information that was redacted from testimony and reports by re-filing the testimony or reports in an un-redacted form. If any Company highly confidential modeling inputs and assumptions listed above under highly confidential information are entered into the record in any manner, the Company will seek to indefinitely continue the confidentiality protections ordered by the Commission.

14.0 Water Usage

The Company's generation facilities vary in their water consumption. Table 14-1 identifies the actual gallons consumed by the Company's existing facilities in 2025 and the gallons consumed per MWh, also known as water intensity, for the current generation fleet.

Table 14-1
Water Usage – Existing Generating Facilities

Unit Name	Fuel Type	2025 Energy Produced (MWh)	2025 Water Consumption (gallons)	Water Intensity (gallons/MWh)
PAGS CT 1	Nat Gas	248,688	59,619,034	159.99
PAGS CT 2	Nat Gas	272,596	65,350,611	159.99
LMCC1	Nat Gas	577,768	138,510,730	278.82
LMCC2	Nat Gas	499,273	119,692,796	278.82
LM6000	Nat Gas	6,590	1,579,842	159.99
Airport Diesels	#2 Oil	Negligible	Negligible	Negligible
Rocky Ford Diesels	#2 Oil	Negligible	Negligible	Negligible
Annual Total		**1,604,915**	**384,753,013**	

Table 14-2 shows the expected annual water consumption for conventional resources that were included in the analysis of future resources in this Plan. Water consumption values were forecasted assuming a 30, 80, or 85 percent capacity factor, as indicated in the table, for the possible resources.

Table 14-2
Water Resources – Potential Generating Facilities

Unit Name	Capacity Factor	Fuel Type	Annual Water Intensity (Gallons/MWh)	Possible Annual Water Consumption (Gallons)
2x1 LM6000 PF+ CC	80%	Natural Gas	470	536,882,880
1x1 LM6000 PF+ CC	80%	Natural Gas	480	272,471,040
1x0 LM6000 PF+ SC	30%	Natural Gas	10	1,182,600
1x0 RICE	30%	Natural Gas	0	0
Small Modular Reactor	85%	Nuclear	558	249,292,080
Brownfield CC Generation	80%	Natural Gas	289	202,531,200

15.0 Conclusion

The Company is pleased to present its Ready to Serve Plan, and the Company respectfully requests that the Commission approve the Company's preferred portfolio as an important step to achieving the emissions reductions targets required under Colorado law. The Company looks forward to the Commission's and other parties' involvement in evaluating this plan and in selecting a portfolio of resources for procurement in the Phase II competitive solicitation.

Appendix A
General Planning Assumptions

The planning assumptions shown in Table A-1 will underline the evaluation of proposals received in response to any Company solicitation in Phase II of these 2026 ERP proceedings. Note that the following is not a complete listing of all assumptions that will be applied in the evaluation process. In addition, the assumptions noted below represent "base case" assumptions. Sensitivity analysis will be performed in which several of these assumptions are altered in accordance with Commission directives.

Table A-1
General Planning Assumptions

Item	2026 ERP Assumption	Updated in Phase II
Conventional and Renewable resource options considered	See Section 5.4	No
Conventional resource options prices	See Section 5.4	No
Renewable resource options prices	See Section 5.4	No
Cost of integrating resources	See Section 6.1	Yes
DSM forecast	See Section 3.6	No
Large customer forecast	See Section 4.3.3	If appropriate
Social costs of emissions	See Section 3.5	No
Financial parameters	See Table 3-5	No
General inflation rate	2.31%	If appropriate
Load forecast	See Section 4.0	No
Market prices	Energy Strategies Commodity Forecast	Yes
Natural gas prices	Energy Strategies Commodity Forecast	Yes
Existing unit operating characteristics and costs	See Table 5-1,5-2, and Highly Confidential Appendix F	No
Existing unit retirement dates	See Table 5-1,5-2, and Highly Confidential Appendix F	No
Planning period	25 years	No
Planning reserve margin	See Section 6.6 Modeled: 8.4% Summer & 19.6% Winter	Final Study: 8.5% Summer & 18.5% Winter; If

Item	2026 ERP Assumption	Updated in Phase II
	Final Study: 8.5% Summer & 18.5% Winter	appropriate due to unfolding market impacts
Effective Load Carrying Capability	See Section 6.3, 6.4, and 6.5	If appropriate due to unfolding market impacts
Power purchase contracts	See Section 5.2	No
Resource Acquisition Period	7 years	No
Seasonal firm market purchases	See Section 5.4.4	No

Appendix B
Confidential Net Base Econometric Load Forecast Methodology

See separate appendix.

Overview of Long-Term Energy, Demand, and Customer Forecasting Models (report)

Schedule B1-1	Historical and Forecasted Economic Data
Schedule B1-2	Monthly Historical Demand Data
Schedule B1-3	Historical and Forecasted Weather Data Used in Demand Model
Schedule B1-4	Base Monthly Customer Class Demand Forecast
Schedule B1-5	Base Annual Customer Class Demand Forecast
Schedule B1-6	Historical and Forecasted Variable Values for Residential Non-BTM kW Per Meter Model
Schedule B1-7	Variable Statistical Values for Residential Non-BTM kW Per Meter Model
Schedule B1-8	Historical and Forecasted Variable Values for Residential BTM kW Per Meter Model
Schedule B1-9	Variable Statistical Values for Residential BTM kW Per Meter Model
Schedule B1-10	Historical and Forecasted Variable Values for Small General Service Non-BTM kW Per Meter Model
Schedule B1-11	Variable Statistical Values for Small General Service Non-BTM kW Per Meter Model
Schedule B1-12	Historical and Forecasted Variable Values for Small General Service BTM kW Per Meter Model
Schedule B1-13	Variable Statistical Values for Small General Service BTM kW Per Meter Model
Schedule B1-14	Historical and Forecasted Variable Values for Large General Service Non-BTM kW Per Meter Model
Schedule B1-15	Variable Statistical Values for Large General Service Non-BTM kW Per Meter Model
Schedule B1-16	Historical and Forecasted Variable Values for Large General Service BTM kW Per Meter Model
Schedule B1-17	Variable Statistical Values for Large General Service BTM kW Per Meter Model
Schedule B1-18	Historical and Forecasted Variable Values for Large Power Service Non-BTM MW Model
Schedule B1-19	Variable Statistical Values for Large Power Service Non-BTM MW Model
Schedule B1-20	Historical and Forecasted Variable Values for Large Power Service BTM MW Model

Schedule B1-21	Variable Statistical Values for Large Power Service BTM MW Model
Schedule B2-1	Historical and Forecasted Economic Data
Schedule B2-2	Monthly Historic Energy
Schedule B2-3	Historical and Forecasted Weather Data Used in Energy Models
Schedule B2-4	Base Monthly Customer Class Energy Forecast
Schedule B2-5	Base Annual Customer Class Energy Forecast
Schedule B2-6	Historical and Forecasted Variable Values for Residential Non-BTM Use Per Meter Model
Schedule B2-7	Variable Statistical Values for Residential Non-BTM Use Per Meter Model
Schedule B2-8	Historical and Forecasted Variable Values for Residential BTM Use Per Meter Model
Schedule B2-9	Variable Statistical Values for Residential BTM Use Per Meter Model
Schedule B2-10	Historical and Forecasted Variable Values for Small General Service Non-BTM Use Per Meter Model
Schedule B2-11	Variable Statistical Values for Small General Service Non-BTM Use Per Meter Model
Schedule B2-12	Historical and Forecasted Variable Values for Small General Service BTM Use Per Meter Model
Schedule B2-13	Variable Statistical Values for Small General Service BTM Use Per Meter Model
Schedule B2-14	Historical and Forecasted Variable Values for Large General Service Non-BTM Use Per Meter Model
Schedule B2-15	Variable Statistical Values for Large General Service Non-BTM Use Per Meter Model
Schedule B2-16	Historical and Forecasted Variable Values for Large General Service BTM Use Per Meter Model
Schedule B2-17	Variable Statistical Values for Large General Service BTM Use Per Meter Model
Schedule B2-18	Historical and Forecasted Variable Values for Large Power Service Non-BTM Sales Model
Schedule B2-19	Variable Statistical Values for Large Power Service Non-BTM Sales Model
Schedule B2-20	Historical and Forecasted Variable Values for Large Power Service BTM Sales Model
Schedule B2-21	Variable Statistical Values for Large Power Service BTM Sales Model
Schedule B3-1	Historical and Forecasted Economic Data
Schedule B3-2	Base Monthly Customer Class Forecast
Schedule B3-3	Base Annual Customer Class Forecast
Schedule B3-4	Historical and Forecasted Variable Values for Residential Customer Model

Schedule B3-5 Variable Statistical Values for Residential Customer Model
Schedule B3-6 Historical and Forecasted Variable Values for Small General Service Customer Model
Schedule B3-7 Variable Statistical Values for Small General Service Customer Model
Schedule B3-8 Historical and Forecasted Variable Values for Large General Service Customer Model
Schedule B3-9 Variable Statistical Values for Large General Service Customer Model
Schedule B3-10 Historical and Forecasted Variable Values for Large Power Service Customer Model
Schedule B3-11 Variable Statistical Values for Large Power Service Customer Model

Appendix C
BTM & CSG Forecasts for the Gross Load Forecast

See separate appendix.

Schedule C-1	Base Monthly BTM Production Demand Forecast
Schedule C-2	Base Annual BTM Production Demand Forecast
Schedule C-3	Base Monthly BTM Production Energy Forecast
Schedule C-4	Base Annual BTM Production Energy Forecast
Schedule C-5	Monthly Historic Demand (MW)
Schedule C-6	Monthly Historic Energy (MWh)
Schedule C-7	Historical and Forecasted Weather Data Used in Demand Models
Schedule C-8	Historical and Forecasted Weather Data Used in Energy Models
Schedule C-9	Historical and Forecasted Variable Values for Production BTM kW Per Meter Model
Schedule C-10	Variable Statistical Values for Production BTM kW Per Meter Model
Schedule C-11	Historical and Forecasted Variable Values for Production BTM Use Per Meter Mode
Schedule C-12	Variable Statistical Values for Production BTM Use Per Meter Model
Schedule C-13	Resulting CSG Demand and Energy Forecasts

Appendix D
Daily Load Profiles

See separate appendix.

Schedule D-1	Residential - January
Schedule D-2	Small General Service - January
Schedule D-3	Large General Service - January
Schedule D-4	Large Power Service - January
Schedule D-5	Residential - February
Schedule D-6	Small General Service - February
Schedule D-7	Large General Service - February
Schedule D-8	Large Power Service - February
Schedule D-9	Residential - March
Schedule D-10	Small General Service - March
Schedule D-11	Large General Service - March
Schedule D-12	Large Power Service - March
Schedule D-13	Residential - April
Schedule D-14	Small General Service - April
Schedule D-15	Large General Service - April
Schedule D-16	Large Power Service - April
Schedule D-17	Residential - May
Schedule D-18	Small General Service - May
Schedule D-19	Large General Service - May
Schedule D-20	Large Power Service - May
Schedule D-21	Residential - June
Schedule D-22	Small General Service - June
Schedule D-23	Large General Service - June
Schedule D-24	Large Power Service - June
Schedule D-25	Residential - July
Schedule D-26	Small General Service - July
Schedule D-27	Large General Service - July
Schedule D-28	Large Power Service - July
Schedule D-29	Residential - August
Schedule D-30	Small General Service - August
Schedule D-31	Large General Service - August
Schedule D-32	Large Power Service - August
Schedule D-33	Residential - September
Schedule D-34	Small General Service - September
Schedule D-35	Large General Service - September
Schedule D-36	Large Power Service - September
Schedule D-37	Residential - October
Schedule D-38	Small General Service - October
Schedule D-39	Large General Service - October

Schedule D-40	Large Power Service - October
Schedule D-41	Residential - November
Schedule D-42	Small General Service - November
Schedule D-43	Large General Service - November
Schedule D-44	Large Power Service - November
Schedule D-45	Residential - December
Schedule D-46	Small General Service - December
Schedule D-47	Large General Service - December
Schedule D-48	Large Power Service - December

Appendix E
Colorado Electric Busbar Cost Study

See separate appendix.

Appendix F
Highly Confidential E3 Technical Report

See separate appendix.

Appendix G
2026 - 2050 Load and Resource Balances

See separate appendix.

Schedule G-1	Annual Load and Resource Balance - Base Case - 2026-2050
Schedule G-2	Monthly Load and Resource Balance - Base Case - 2026-2032
Schedule G-3	Annual Load and Resource Balance - Preferred Plan - 2026-2050
Schedule G-4	Monthly Load and Resource Balance - Preferred Plan - 2026-2032

Appendix H
Commodity Price Forecasts

See separate appendix.

Schedule H-1	Natural Gas Price Forecast – NG Colorado Market – Base Case
Schedule H-2	Natural Gas Price Forecast – NG Colorado Market – Low Gas Case
Schedule H-3	Natural Gas Price Forecast – NG Colorado Market – High Gas Case
Schedule H-4	Oil Price Forecast – No. 2 Distillate – Base Case
Schedule H-5	Clean Fuel Price Forecast – Black & Veatch Busbar Study – Base Case
Schedule H-6	Market Energy Price Forecast – AZ-PV/Mid-C Markets – Base Case
Schedule H-7	Market Energy Price Forecast – AZ-PV/Mid-C Markets – Low Gas Case
Schedule H-8	Market Energy Price Forecast – AZ-PV/Mid-C Markets – High Gas Case

Appendix I
BHCOE Transmission Line Loss Study

See separate appendix.

Appendix J
BHCOE Distribution Line Loss Study

See separate appendix.

Appendix K
Emissions Projections

Table K-1 Annual Projected SO_2 Emissions from Existing Resources (Tons)
Table K-2 Annual Projected SO_2 Emissions from Existing Resources (lbs/MWh)
Table K-3 Annual Projected SO_2 Emissions from Generic Resources (Tons)
Table K-4 Annual Projected SO_2 Emissions from Generic Resources (lbs/MWh)
Table K-5 Annual Projected CO_2 Emissions from Existing Resources (Tons)
Table K-6 Annual Projected CO_2 Emissions from Existing Resources (lbs/MWh)
Table K-7 Annual Projected CO_2 Emissions from Generic Resources (Tons)
Table K-8 Annual Projected CO_2 Emissions from Generic Resources (lbs/MWh)
Table K-9 Annual Projected NO_x Emissions from Existing Resources (Tons)
Table K-10 Annual Projected NO_x Emissions from Existing Resources (lbs/MWh)
Table K-11 Annual Projected NO_x Emissions from Generic Resources (Tons)
Table K-12 Annual Projected NO_x Emissions from Generic Resources (lbs/MWh)
Table K-13 Annual Projected PM Emissions from Existing Resources (Tons)
Table K-14 Annual Projected PM Emissions from Existing Resources (lbs/MWh)
Table K-15 Annual Projected PM Emissions from Generic Resources (Tons)
Table K-16 Annual Projected PM Emissions from Generic Resources (lbs/MWh)
Table K-17 Annual Projected Hg Emissions from Existing Resources (Tons)
Table K-18 Annual Projected Hg Emissions from Existing Resources (lbs/MWh)
Table K-19 Annual Projected Hg Emissions from Generic Resources (Tons)
Table K-20 Annual Projected Hg Emissions from Generic Resources (lbs/MWh)
Table K-21 Annual Projected CH_4 Emissions from Existing Resources (Tons)
Table K-22 Annual Projected CH_4 Emissions from Existing Resources (lbs/MWh)
Table K-23 Annual Projected CH_4 Emissions from Generic Resources (Tons)
Table K-24 Annual Projected CH_4 Emissions from Generic Resources (lbs/MWh)
Table K-25 Annual Projected N_2O Emissions from Existing Resources (Tons)
Table K-26 Annual Projected N_2O Emissions from Existing Resources (lbs/MWh)
Table K-27 Annual Projected N_2O Emissions from Generic Resources (Tons)
Table K-28 Annual Projected N_2O Emissions from Generic Resources (lbs/MWh)
Table K-29 Annual Projected CO_2e Emissions from Existing Resources (Tons)
Table K-30 Annual Projected CO_2e Emissions from Existing Resources (lbs/MWh)
Table K-31 Annual Projected CO_2e Emissions from Generic Resources (Tons)
Table K-32 Annual Projected CO_2e Emissions from Generic Resources (lbs/MWh)

Certain greenhouse gas (GHG) emission values in the ERP modeling may differ slightly from those reported in the CDPHE workbook due to workbook limitations that prevent the assignment of unit-specific CH_4 and N_2O emission factors. These minor variances have no material impact on overall emissions reduction outcomes and represent only a negligible portion of projected 2030 GHG emissions.

Table K-1
Annual Projected SO_2 Emissions from Existing Resources (Tons)

Year	CEP No SCC (Tons)
2026	2.48
2027	2.39
2028	1.69
2029	1.18
2030	1.24
2031	1.20
2032	0.24
2033	0.15
2034	0.13
2035	0.11
2036	0.07
2037	0.09
2038	0.08
2039	0.09
2040	0.10
2041	0.05
2042	0.04
2043	0.04
2044	0.05
2045	0.06
2046	0.06
2047	0.01
2048	0.01
2049	0.01
2050	0.00

Table K-2
Annual Projected SO_2 Emissions from Existing Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.0042
2027	0.0043
2028	0.0041
2029	0.0042
2030	0.0041
2031	0.0041
2032	0.0055
2033	0.0055
2034	0.0055
2035	0.0055
2036	0.0055
2037	0.0055
2038	0.0055
2039	0.0055
2040	0.0055
2041	0.0055
2042	0.0055
2043	0.0055
2044	0.0055
2045	0.0055
2046	0.0055
2047	0.0057
2048	0.0057
2049	0.0057
2050	0.0000

Table K-3
Annual Projected SO_2 Emissions from Generic Resources (Tons)

Year	CEP No SCC (Tons)
2026	0.00
2027	0.00
2028	0.00
2029	0.08
2030	0.18
2031	0.09
2032	1.39
2033	1.45
2034	1.37
2035	1.34
2036	1.26
2037	0.98
2038	0.91
2039	0.82
2040	0.69
2041	0.56
2042	0.53
2043	0.56
2044	0.39
2045	0.30
2046	0.24
2047	0.15
2048	0.14
2049	0.10
2050	0.00

Table K-4
Annual Projected SO_2 Emissions from Generic Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.012
2027	0.012
2028	0.012
2029	0.012
2030	0.012
2031	0.012
2032	0.012
2033	0.012
2034	0.012
2035	0.012
2036	0.012
2037	0.012
2038	0.012
2039	0.012
2040	0.012
2041	0.012
2042	0.012
2043	0.012
2044	0.012
2045	0.012
2046	0.012
2047	0.012
2048	0.012
2049	0.012
2050	0.000

Table K-5
Annual Projected CO_2 Emissions from Existing Resources (Tons)

Year	CEP No SCC (Tons)
2026	489,085.49
2027	472,575.39
2028	333,542.21
2029	233,988.83
2030	245,153.66
2031	236,972.40
2032	48,059.85
2033	29,634.13
2034	25,876.93
2035	22,228.62
2036	13,381.62
2037	16,976.36
2038	15,653.78
2039	18,486.46
2040	20,226.61
2041	10,325.43
2042	8,693.60
2043	8,448.48
2044	10,840.51
2045	11,339.60
2046	12,645.20
2047	1,264.90
2048	1,146.58
2049	1,138.44
2050	0.00

Table K-6
Annual Projected CO_2 Emissions from Existing Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	828.81
2027	844.05
2028	808.49
2029	832.27
2030	808.50
2031	803.93
2032	1,085.79
2033	1,085.62
2034	1,085.70
2035	1,086.44
2036	1,086.79
2037	1,087.27
2038	1,087.84
2039	1,087.96
2040	1,087.91
2041	1,090.16
2042	1,090.63
2043	1,091.35
2044	1,091.66
2045	1,089.58
2046	1,091.91
2047	1,128.71
2048	1,124.10
2049	1,118.80
2050	0.00

Table K-7
Annual Projected CO_2 Emissions from Generic Resources (Tons)

Year	CEP No SCC (Tons)
2026	0.00
2027	0.00
2028	0.00
2029	6,721.95
2030	14,929.14
2031	7,295.10
2032	118,148.29
2033	123,570.33
2034	116,078.30
2035	113,783.81
2036	107,276.45
2037	83,542.77
2038	77,203.83
2039	70,025.76
2040	58,872.15
2041	47,977.94
2042	45,130.76
2043	47,680.31
2044	33,115.78
2045	25,523.41
2046	20,007.38
2047	12,951.33
2048	12,258.94
2049	8,714.60
2050	0.00

Table K-8
Annual Projected CO_2 Emissions from Generic Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	1,020.00
2027	1,020.00
2028	1,020.00
2029	1,020.00
2030	1,020.00
2031	1,020.00
2032	1,020.00
2033	1,020.00
2034	1,020.00
2035	1,020.00
2036	1,020.00
2037	1,020.00
2038	1,020.00
2039	1,020.00
2040	1,020.00
2041	1,020.00
2042	1,020.00
2043	1,020.00
2044	1,020.00
2045	1,020.00
2046	1,020.00
2047	1,020.00
2048	1,020.00
2049	1,020.00
2050	0.00

Table K-9
Annual Projected NO_x Emissions from Existing Resources (Tons)

Year	CEP No SCC (Tons)
2026	49.43
2027	50.55
2028	33.04
2029	24.70
2030	24.25
2031	23.12
2032	7.71
2033	4.75
2034	4.15
2035	3.57
2036	2.15
2037	2.72
2038	2.51
2039	2.97
2040	3.25
2041	1.66
2042	1.40
2043	1.36
2044	1.74
2045	1.82
2046	2.03
2047	0.20
2048	0.18
2049	0.18
2050	0.00

Table K-10
Annual Projected NO_x Emissions from Existing Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.08
2027	0.09
2028	0.08
2029	0.09
2030	0.08
2031	0.08
2032	0.17
2033	0.17
2034	0.17
2035	0.17
2036	0.17
2037	0.17
2038	0.17
2039	0.17
2040	0.17
2041	0.17
2042	0.18
2043	0.18
2044	0.18
2045	0.17
2046	0.18
2047	0.18
2048	0.18
2049	0.18
2050	0.00

Table K-11
Annual Projected NO_x Emissions from Generic Resources (Tons)

Year	CEP No SCC (Tons)
2026	0.00
2027	0.00
2028	0.00
2029	1.65
2030	3.66
2031	1.79
2032	28.96
2033	30.29
2034	28.45
2035	27.89
2036	26.29
2037	20.48
2038	18.92
2039	17.16
2040	14.43
2041	11.76
2042	11.06
2043	11.69
2044	8.12
2045	6.26
2046	4.90
2047	3.17
2048	3.00
2049	2.14
2050	0.00

Table K-12
Annual Projected NO_x Emissions from Generic Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.25
2027	0.25
2028	0.25
2029	0.25
2030	0.25
2031	0.25
2032	0.25
2033	0.25
2034	0.25
2035	0.25
2036	0.25
2037	0.25
2038	0.25
2039	0.25
2040	0.25
2041	0.25
2042	0.25
2043	0.25
2044	0.25
2045	0.25
2046	0.25
2047	0.25
2048	0.25
2049	0.25
2050	0.00

Table K-13
Annual Projected PM Emissions from Existing Resources (Tons)

Year	CEP No SCC (Tons)
2026	450.74
2027	433.99
2028	307.70
2029	214.51
2030	226.20
2031	219.16
2032	40.68
2033	25.06
2034	21.88
2035	18.82
2036	11.34
2037	14.36
2038	13.26
2039	15.67
2040	17.13
2041	8.81
2042	7.38
2043	7.18
2044	9.27
2045	9.66
2046	10.80
2047	1.18
2048	1.07
2049	1.06
2050	0.00

Table K-14
Annual Projected PM Emissions from Existing Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.76
2027	0.78
2028	0.75
2029	0.76
2030	0.75
2031	0.74
2032	0.92
2033	0.92
2034	0.92
2035	0.92
2036	0.92
2037	0.92
2038	0.92
2039	0.92
2040	0.92
2041	0.93
2042	0.93
2043	0.93
2044	0.93
2045	0.93
2046	0.93
2047	1.05
2048	1.05
2049	1.04
2050	0.00

Table K-15
Annual Projected PM Emissions from Generic Resources (Tons)

Year	CEP No SCC (Tons)
2026	0.00
2027	0.00
2028	0.00
2029	1.65
2030	3.66
2031	1.79
2032	28.96
2033	30.29
2034	28.45
2035	27.89
2036	26.29
2037	20.48
2038	18.92
2039	17.16
2040	14.43
2041	11.76
2042	11.06
2043	11.69
2044	8.12
2045	6.26
2046	4.90
2047	3.17
2048	3.00
2049	2.14
2050	0.00

Table K-16
Annual Projected PM Emissions from Generic Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.25
2027	0.25
2028	0.25
2029	0.25
2030	0.25
2031	0.25
2032	0.25
2033	0.25
2034	0.25
2035	0.25
2036	0.25
2037	0.25
2038	0.25
2039	0.25
2040	0.25
2041	0.25
2042	0.25
2043	0.25
2044	0.25
2045	0.25
2046	0.25
2047	0.25
2048	0.25
2049	0.25
2050	0.00

Table K-17
Annual Projected Hg Emissions from Existing Resources (Tons)

Year	CEP No SCC (Tons)
2026	0.00
2027	0.00
2028	0.00
2029	0.00
2030	0.00
2031	0.00
2032	0.00
2033	0.00
2034	0.00
2035	0.00
2036	0.00
2037	0.00
2038	0.00
2039	0.00
2040	0.00
2041	0.00
2042	0.00
2043	0.00
2044	0.00
2045	0.00
2046	0.00
2047	0.00
2048	0.00
2049	0.00
2050	0.00

Table K-18
Annual Projected Hg Emissions from Existing Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.00
2027	0.00
2028	0.00
2029	0.00
2030	0.00
2031	0.00
2032	0.00
2033	0.00
2034	0.00
2035	0.00
2036	0.00
2037	0.00
2038	0.00
2039	0.00
2040	0.00
2041	0.00
2042	0.00
2043	0.00
2044	0.00
2045	0.00
2046	0.00
2047	0.00
2048	0.00
2049	0.00
2050	0.00

Table K-19
Annual Projected Hg Emissions from Generic Resources (Tons)

Year	CEP No SCC (Tons)
2026	0.00
2027	0.00
2028	0.00
2029	0.00
2030	0.00
2031	0.00
2032	0.00
2033	0.00
2034	0.00
2035	0.00
2036	0.00
2037	0.00
2038	0.00
2039	0.00
2040	0.00
2041	0.00
2042	0.00
2043	0.00
2044	0.00
2045	0.00
2046	0.00
2047	0.00
2048	0.00
2049	0.00
2050	0.00

Table K-20
Annual Projected Hg Emissions from Generic Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.00
2027	0.00
2028	0.00
2029	0.00
2030	0.00
2031	0.00
2032	0.00
2033	0.00
2034	0.00
2035	0.00
2036	0.00
2037	0.00
2038	0.00
2039	0.00
2040	0.00
2041	0.00
2042	0.00
2043	0.00
2044	0.00
2045	0.00
2046	0.00
2047	0.00
2048	0.00
2049	0.00
2050	0.00

Table K-21
Annual Projected CH_4 Emissions from Existing Resources (Tons)

Year	CEP No SCC (Tons)
2026	9.08
2027	8.77
2028	6.19
2029	4.34
2030	4.55
2031	4.40
2032	0.89
2033	0.55
2034	0.48
2035	0.41
2036	0.25
2037	0.32
2038	0.29
2039	0.34
2040	0.38
2041	0.19
2042	0.16
2043	0.16
2044	0.20
2045	0.21
2046	0.23
2047	0.02
2048	0.02
2049	0.02
2050	0.00

Table K-22
Annual Projected CH_4 Emissions from Existing Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.02
2027	0.02
2028	0.02
2029	0.02
2030	0.02
2031	0.01
2032	0.02
2033	0.02
2034	0.02
2035	0.02
2036	0.02
2037	0.02
2038	0.02
2039	0.02
2040	0.02
2041	0.02
2042	0.02
2043	0.02
2044	0.02
2045	0.02
2046	0.02
2047	0.02
2048	0.02
2049	0.02
2050	0.00

Table K-23
Annual Projected CH_4 Emissions from Generic Resources (Tons)

Year	CEP No SCC (Tons)
2026	0.00
2027	0.00
2028	0.00
2029	0.13
2030	0.28
2031	0.14
2032	2.23
2033	2.34
2034	2.19
2035	2.15
2036	2.03
2037	1.58
2038	1.46
2039	1.32
2040	1.11
2041	0.91
2042	0.85
2043	0.90
2044	0.63
2045	0.48
2046	0.38
2047	0.24
2048	0.23
2049	0.16
2050	0.00

Table K-24
Annual Projected CH_4 Emissions from Generic Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.02
2027	0.02
2028	0.02
2029	0.02
2030	0.02
2031	0.02
2032	0.02
2033	0.02
2034	0.02
2035	0.02
2036	0.02
2037	0.02
2038	0.02
2039	0.02
2040	0.02
2041	0.02
2042	0.02
2043	0.02
2044	0.02
2045	0.02
2046	0.02
2047	0.02
2048	0.02
2049	0.02
2050	0.00

Table K-25
Annual Projected N_2O Emissions from Existing Resources (Tons)

Year	CEP No SCC (Tons)
2026	0.91
2027	0.88
2028	0.62
2029	0.43
2030	0.45
2031	0.44
2032	0.09
2033	0.06
2034	0.05
2035	0.04
2036	0.02
2037	0.03
2038	0.03
2039	0.03
2040	0.04
2041	0.02
2042	0.02
2043	0.02
2044	0.02
2045	0.02
2046	0.02
2047	0.00
2048	0.00
2049	0.00
2050	0.00

Table K-26
Annual Projected N_2O Emissions from Existing Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.00
2027	0.00
2028	0.00
2029	0.00
2030	0.00
2031	0.00
2032	0.00
2033	0.00
2034	0.00
2035	0.00
2036	0.00
2037	0.00
2038	0.00
2039	0.00
2040	0.00
2041	0.00
2042	0.00
2043	0.00
2044	0.00
2045	0.00
2046	0.00
2047	0.00
2048	0.00
2049	0.00
2050	0.00

Table K-27
Annual Projected N_2O Emissions from Generic Resources (Tons)

Year	CEP No SCC (Tons)
2026	0.00
2027	0.00
2028	0.00
2029	0.04
2030	0.08
2031	0.04
2032	0.62
2033	0.65
2034	0.61
2035	0.60
2036	0.56
2037	0.44
2038	0.41
2039	0.37
2040	0.31
2041	0.25
2042	0.24
2043	0.25
2044	0.17
2045	0.13
2046	0.11
2047	0.07
2048	0.06
2049	0.05
2050	0.00

Table K-28
Annual Projected N_2O Emissions from Generic Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	0.01
2027	0.01
2028	0.01
2029	0.01
2030	0.01
2031	0.01
2032	0.01
2033	0.01
2034	0.01
2035	0.01
2036	0.01
2037	0.01
2038	0.01
2039	0.01
2040	0.01
2041	0.01
2042	0.01
2043	0.01
2044	0.01
2045	0.01
2046	0.01
2047	0.01
2048	0.01
2049	0.01
2050	0.00

Table K-29
Annual Projected CO_2e Emissions from Existing Resources (Tons)

Year	CEP No SCC (Tons)
2026	489,583.86
2027	473,057.08
2028	333,882.05
2029	234,227.29
2030	245,403.44
2031	237,213.84
2032	48,108.89
2033	29,664.36
2034	25,903.33
2035	22,251.30
2036	13,395.28
2037	16,993.68
2038	15,669.75
2039	18,505.33
2040	20,247.25
2041	10,335.96
2042	8,702.47
2043	8,457.10
2044	10,851.57
2045	11,351.17
2046	12,658.10
2047	1,266.20
2048	1,147.75
2049	1,139.60
2050	0.00

Table K-30
Annual Projected CO_2e Emissions from Existing Resources (lbs/MWh)

Year	CEP No SCC (lbs/MWh)
2026	829.65
2027	844.91
2028	809.32
2029	833.12
2030	809.32
2031	804.75
2032	1,086.90
2033	1,086.73
2034	1,086.81
2035	1,087.55
2036	1,087.90
2037	1,088.38
2038	1,088.95
2039	1,089.07
2040	1,089.02
2041	1,091.27
2042	1,091.75
2043	1,092.46
2044	1,092.77
2045	1,090.69
2046	1,093.03
2047	1,129.87
2048	1,125.25
2049	1,119.95
2050	0.00

Table K-31
Annual Projected CO_2e Emissions from Generic Resources (Tons)

Year	CEP No SCC (Tons)
2026	0.00
2027	0.00
2028	0.00
2029	6,736.04
2030	14,960.44
2031	7,310.39
2032	118,396.00
2033	123,829.40
2034	116,321.67
2035	114,022.37
2036	107,501.36
2037	83,717.93
2038	77,365.69
2039	70,172.57
2040	58,995.58
2041	48,078.53
2042	45,225.38
2043	47,780.27
2044	33,185.21
2045	25,576.93
2046	20,049.32
2047	12,978.48
2048	12,284.64
2049	8,732.87
2050	0.00

Table K-32
Annual Projected CO_2e Emissions from Generic Resources (lbs/MWh)

Year	CEP No SCC (Tons)
2026	0.00
2027	0.00
2028	0.00
2029	1,022.14
2030	1,022.14
2031	1,022.14
2032	1,022.14
2033	1,022.14
2034	1,022.14
2035	1,022.14
2036	1,022.14
2037	1,022.14
2038	1,022.14
2039	1,022.14
2040	1,022.14
2041	1,022.14
2042	1,022.14
2043	1,022.14
2044	1,022.14
2045	1,022.14
2046	1,022.14
2047	1,022.14
2048	1,022.14
2049	1,022.14
2050	0.00

Appendix L
Air Pollution Control Division Verification Workbooks

See separately filed appendices.

Appendix L-1 - Base ERP Verification Workbook
Appendix L-2 - CEP Verification Workbook
Appendix L-3 - ERP No SCC Verification Workbook
***Appendix L-4 - CEP No SCC Verification Workbook**
Appendix L-5 - CEP Increased Electrification Verification Workbook
Appendix L-6 - CEP Low Load Verification Workbook
Appendix L-7 - CEP High Load Verification Workbook
Appendix L-8 - CEP Low Gas Verification Workbook
Appendix L-9 - CEP High Gas Verification Workbook
Appendix L-10 - CEP No Gas Builds Verification Workbook
Appendix L-11 - CEP No SCC (Discounted Gas) Verification Workbook
Appendix L-12 - ERP No SCC (Discounted Gas) Verification Workbook
Appendix L-13 - CEP 2040 Emissions Target Verification Workbook
Appendix L-14 - CEP No SCC 2040 Emissions Target Verification Workbook

***Ready to Serve Preferred Portfolio**

Appendix M

Computer Modules Used for the Electric Resource Plan

In developing resource plans for Black Hills, E3 conducted resource adequacy analysis using RECAP, capacity expansion simulations and system operations simulations were conducted using PLEXOS LT and PLEXOS ST, respectively. Summary descriptions of the models are included below. Detailed descriptions are included in Highly Confidential Appendix F.

RECAP Model Description

The resource adequacy analysis for Black Hills used E3's Renewable Energy Capacity Planning (RECAP) model, developed and maintained by E3, to calculate the PRM requirement to maintain Black Hills' reliability standard as well as ELCC values for all resources including existing, planned, and future candidate resources. RECAP is a loss-of-load-probability model designed to evaluate the resource adequacy of electric power systems, including systems with high penetrations of renewable energy and other dispatch-limited resources such as hydropower, energy storage, and demand response.

RECAP evaluates resource adequacy through time-sequential simulations of hundreds of years of plausible system conditions to calculate a statistically significant measure of system reliability metrics, which in turn can be used to derive PRM requirements and ELCC values for different types of generation resources. RECAP simulates the availability of electric supply to meet demand across a broad range of conditions, accounting for factors such as weather-driven variability of electric demand, the natural variability of resources such as wind and solar, and operating constraints for resources like storage. RECAP also introduces stochastic forced outages of thermal plants and transmission assets and time-sequentially tracks hydropower, demand response, and storage state of charge. RECAP simulations evaluate the likelihood and magnitude of loss of load – energy demand that cannot be served – and provide the basis for calculating the PRM.

PLEXOS Model Description

PLEXOS LT is a capacity expansion model that uses linear programming to identify optimal long-term generation and transmission investments in an electric system, subject to reliability, technical, and policy constraints. Designed specifically to address the long-term planning and procurement needs in systems seeking to integrate large quantities of variable resources, PLEXOS layers capacity expansion logic on top of a production cost model to identify a least-cost investment plan that accounts for both the upfront capital costs of new resources and the variable costs to operate the grid reliably over time. PLEXOS's optimization capabilities allow it to construct a portfolio from a wide range of potential new resource options. In an environment in which most new investments in the electric system have fixed costs

significantly larger than their variable operating costs, this type of model provides a strong foundation to identify potential investment benefits associated with alternative scenarios.

PLEXOS ST is used to provide granular operational and cost metrics. For this analysis, E3 developed a PLEXOS model incorporating hourly load, renewable profiles, fuel prices, emissions rates, and specific operational properties for existing and planned generators such as variable O&M costs, minimum up time, minimum down time, ramp rate, and heat rates. Given historical load and operational reserve requirements, PLEXOS optimized The Company's generation to meet hourly load while minimizing cost.

Appendix N
All-Source Solicitation Dispatchable & Renewable Resources Request for Proposals

See separate appendix.

The following Model Energy Purchase Agreements are included:

Attachment F-1	Model Renewable Energy Purchase Agreement
Attachment F-2	Model Renewable Generation and Battery Storage Energy Purchase Agreement
Attachment F-3	Model Stand-Alone Battery Storage Energy Services Agreement
Attachment F-4	Model Dispatchable Energy Purchase Agreement
Attachment F-5	Model Build Transfer Agreement

Appendix O
BHCOE Market Impacts Study

See separate appendix.

Abbreviations

AZ-PV – Palo Verde, Arizona Energy Market
BACT – Best Available Control Technology
BES – Bulk Electric System
BESS – Battery Energy Storage System
BHCOE - Black Hills Colorado Electric, LLC
Black Hills - Black Hills Colorado Electric, LLC
BTA – Build Transfer Agreement
Btu – British Thermal Unit
BTM – Behind-the-meter
CC – Combined Cycle
CCPG – Colorado Coordinated Planning Group
CCR – Code of Colorado Regulations
CDD – Cooling Degree Days
CDH – Cooling Degree Hours
CDPHE – Colorado Department of Public Health and Environment
CEP – Clean Energy Plan
CEP Guidance – Clean Energy Plan Guidance
CO_2 – Carbon dioxide
COD – Commercial Operation Dates
Commission – Colorado Public Utilities Commission
Company - Black Hills - Black Hills Colorado Electric, LLC
CPCN – Certificate of Public Convenience and Necessity
CRO – Contingency Reserve Obligation
C.R.S. – Colorado Revised Statutes
CSG- Community Solar Garden
CT – Combustion Turbine
DG – Distributed Generation
DSM – Demand-Side Management
DPC – Demand per Customer
E3 – Energy & Environmental Economics
EGUs - Electric Generating Units
EIA – Energy Information Administration
ELCC – Effective Load Carrying Capability
EPA – Environmental Protection Agency
EPC – Engineering, Procurement, and Construction
ERP – Electric Resource Plan
ERP Rules - Electric Resource Planning Rules, 4 CCR 723-3-3600 *et seq.*
ERZ – Energy Resource Zone
EUE – Expected Unserved Energy
FERC – Federal Energy Regulatory Commission
GDPM – Generation Dispatch and Power Marketing
Gen III+ – Generation III+ Light Water Reactor

Gen IV – Generation IV Advanced Light Water Reactor
GHG – Greenhouse Gas
GRP - Gross Regional Product
GWh – Gigawatt hour
HDD – Heating Degree Days
HDH – Heating Degree Hours
HS – Heavy Summer
ICAP – Installed Capacity
ICS – Inclusive Community Solar
IPP – Independent Power Producer
IQ – Income Qualified
IRA – Inflation Reduction Act
ITC – Investment Tax Credit
IWG – Interagency Working Group
kV – Kilovolt
kW – Kilowatt
kWh – Kilowatt-hour
LGI – Large Generator Interconnection
LGIP – Large Generator Interconnection Process
LLWR – Large Light Water Reactor
LOLE – Loss of Load Expectation
LOLH – Loss of Load Hours
LOLP – Loss of Load Probability
LTP - Local Transmission Plan
LTRA – Long-Term Reliability Assessment
LWR – Light Water Reactor
MATS - EPA's Mercury and Air Toxics Standard
Mid-C – Mid-Continent Energy Market
MISO – Midcontinent Independent System Operator
MSSC – Most Severe Single Contingency
MVS – Modeling and Validation Subcommittee
MW – Megawatt
MWh – Megawatt hour
NCDC - National Climatic Data Center
NERC – North American Electric Reliability Corporation
NLR – National Laboratory of the Rockies
NOAA - National Oceanic and Atmospheric Administration
Non-VER – Non-Variable Energy Resources
OATT – Open Access Transmission Tariff
OB3 – One Big Beautiful Bill
Order 1000 – FERC Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*
OWM – Organized Wholesale Market
PAGS – Pueblo Airport Generating Station

PCAP – Perfect Capacity
PFE – Prohibited Foreign Entity
PPA – Purchase Power Agreement
PSD – Prevention of Significant Deterioration
PSCo – Public Service Company of Colorado
PTC – Production Tax Credit
PV solar – Photovoltaics
PVRR – Present Value of Revenue Requirements
RAC – Reliability Assessment Committee
RAP – Resource Acquisition Period
REC – Renewable Energy Credit
RECAP – Renewable Energy Capacity Planning Software
RES – Renewable Energy Standard
RFP – Request for Proposals
RNG – Renewable Natural Gas
RRR – Rehearing, Re-argument, or Reconsideration
RTO – Regional Transmission Organization
SB – Senate Bill
SCC – Social Cost of Carbon
SCM – Social Cost of Methane
SMR – Small Modular Reactor
SPG – Sub-Regional Planning Group
SPP – Southwest Power Pool
SSPG – Sierra Subregional Planning Group
StS – The Studies Subcommittee
SWAT – Southwest Area Transmission Group
TCPC - Transmission Coordination and Planning Committee
TPL – Transmission Planning
TSD – Technical Support Document
UPC – Use per Customer
VER – Variable Energy Resources
W&P – Woods & Poole Economics, Inc.
WACC – Weighted-Average Cost of Capital
WECC – Western Electricity Coordinating Council
WEIS – Western Energy Imbalance Service
WRAP – Western Resource Adequacy Program
WPP – Western Power Pool