2030 READY:
OUR COLORADO CLEAN ENERGY PLAN

Our path to achieving 80% carbon reduction by 2030

Colorado PUC E-Filings System

Black Hills Colorado Electric, LLC

2022 Electric Resource Plan and Clean Energy Plan

Black Hills Energy
Ready

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(4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3 - PART 3 RULES REGULATING ELECTRIC UTILITIES 4 CSR 240-22.050 (11))
3600 Electric Resource Planning

Rule	Description	Location in Report
3603 Resource Plan Filing Requirements		
3603(a), as modified by Decision No. C22-0173	Plan required to be filed by May 31, 2022	This Plan is being filed by May 31, 2022
3603 (b)	Motions for highly confidential information to be filed at the same time	Motions filed. Section 11.0
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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
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3606 (a) (I)	Coincident summer and winter peak demand and energy by jurisdiction	Section 4.5

Rule	Description	Location in Report
3606 (a) (II)	Coincident summer and winter peak demand and energy by customer class	Waiver requested for peak demand
3606 (a) (III)	Sales to other utilities	Section 4.8
3606 (a) (IV)	Intra-utility capacity and energy use	Section 4.8
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3606 (d)	Data comparison – five years of historical data; last ERP	Section 4.7
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Executive Summary

Black Hills Colorado Electric, LLC d/b/a Black Hills Energy ("Black Hills" or "the Company") is pleased to continue its leadership in Colorado in addressing electric generation emission reductions by presenting this 2022 Electric Resource Plan ("ERP") and Clean Energy Plan ("CEP") (collectively, the "2030 Ready Plan" or the "Plan") to the Colorado Public Utilities Commission ("Commission").

Our 2030 Ready Plan provides a long-term outlook for a carbon-free future. As an early leader in transitioning away from coal combustion generation and toward clean energy resources through the Peak View and Busch Ranch wind facilities, Black Hills' 2030 Ready Plan is built upon years of phased in renewable generation developments that will assist the Company in exceeding the State of Colorado's greenhouse gas 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 nine 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. Our customers value renewable energy, and we are proud our energy supply is one of the cleanest in the state, powered 100 percent by natural gas and renewable energy.

Black Hills currently 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. Because the Company has already transitioned a significant portion of its fleet to low-emission resources, the Company does need not to retire large portions of its generation resources. However, the Company is proposing to retire all diesel peaking generating facilities by 2030.[1]

Our 2030 Ready Plan proposes a 90 percent reduction in carbon dioxide emissions from 2005 levels by 2030, resulting in 79 percent of our customers' electricity being generated by renewable energy in 2030. We'll get there by adding about 450 megawatts (MW) of new clean energy resources to serve our customers, including wind, solar and battery storage, as proposed in our Preferred Plan. The addition of clean energy resources will not only support necessary emission reductions, but also provide opportunities for customer cost savings. Figures ES-1 and ES-2 depict the Company's capacity and energy mix as we continue our transition to 2030.

[1] 18 MW will be retired in 2025 and the remaining 10 MW will be retired by 2030.

Figure ES-1
Projected Capacity Mix by 2030

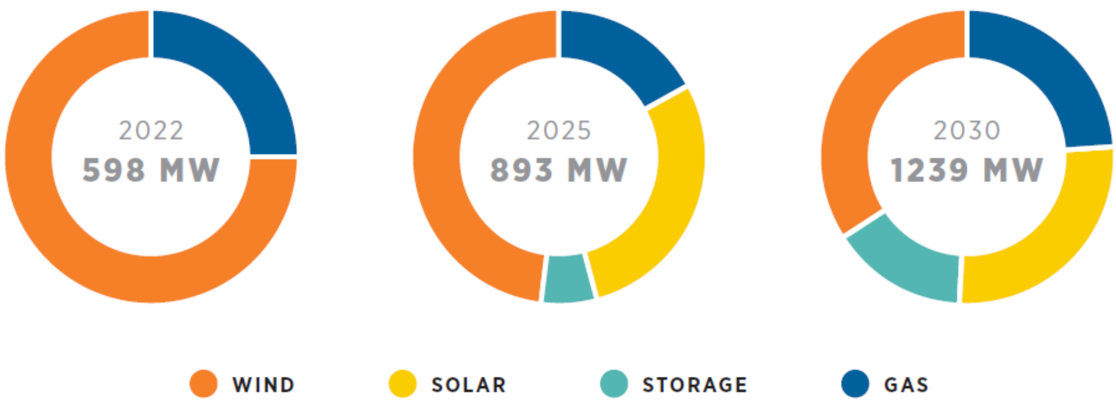
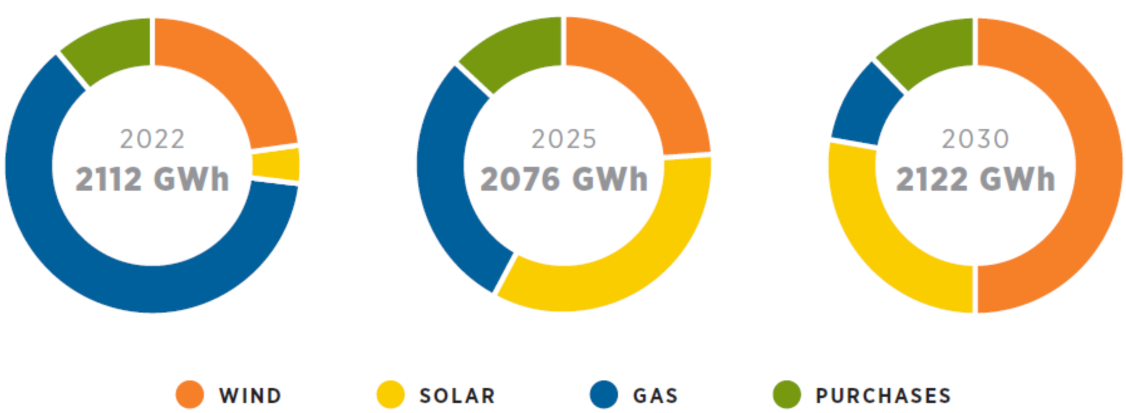


Figure ES-2
Projected Energy Mix by 2030

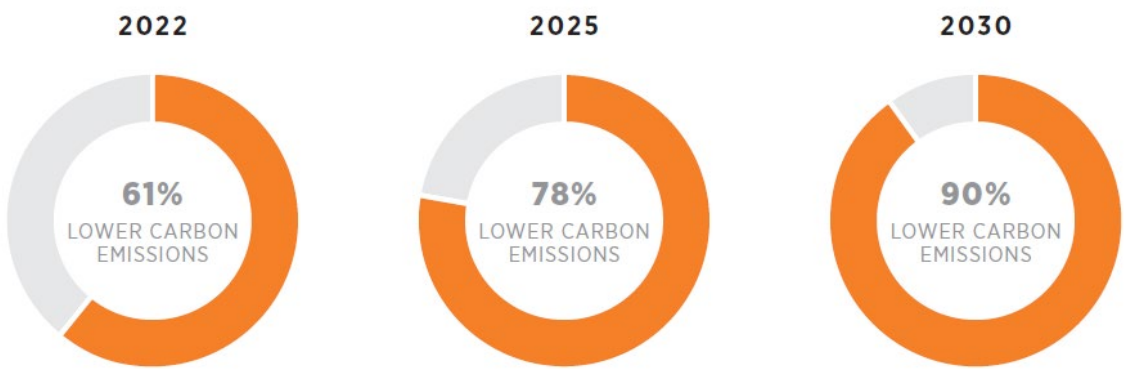


The communities that Black Hills serves are already well-positioned, and in many cases, aligned in their desire to address Colorado's climate policy goals. Black Hills stands ready as a partner to assist the State and its customers in providing the services and offerings necessary to support a safe, reliable, and resilient future. Black Hills is pleased to present our 2030 Ready Plan.

Preferred Plan

Through this Plan, the Company is seeking Commission approval of generation decisions for the nine-year time frame of the Resource Acquisition Period ("RAP"), running through 2030. The Preferred Plan includes resource additions of the following: 149 MW of wind, 258 MW of solar, and 50 MW of battery storage by 2030. These resources will allow the Company to achieve emissions reductions, compared to 2005 levels, of 78% percent in 2025 and 90% 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' CEP goals. 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 2022 to year 2030.

Figure ES-3
Projected Emissions Reductions Mix by 2030



The Company's ability to add new renewable resources through the 2030 Ready Plan is possible in large part due to the flexibility provided by the Pueblo Airport Generating Station ("PAGS"), which the Company considered and planned for when permitting and constructing PAGS. The PAGS facility, located in Pueblo, includes 220 MW of utility-owned natural gas generation and a 200 MW combined-cycle unit that provides capacity and energy to Black Hills through a long-term power purchase agreement. This facility is and will remain critical to ensure Black Hills is able to reliably transition to increased intermittent renewable generation. In particular, the PAGS facility provides critical firm dispatchable capacity services that ensures 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. While the Company's Preferred Plan will result in reduced capacity factors for PAGS, the continued operation of PAGS is a critical component of the 2030 Ready Plan to ensure a seamless conversion to meeting our emission reduction goals.

Projected Costs and Savings

The resource additions contemplated in this Plan are also expected to provide short-term customer bill savings and long-term bill stability. To approximate these savings, the Company has completed a comparative analysis of the continuation of the Company's current resource mix, compared to the resource mix proposed in this Plan. This analysis demonstrates that the addition of clean energy resources in the Preferred Plan will not only support necessary emission reductions, but also provide opportunities for cost savings.

The Company has proposed prudent cost recovery mechanisms which will provide long-term bill stability through 2030 and short-term bill reductions. As provided by SB19-236, the Company is proposing to implement a new cost adjustment equal to the maximum retail rate impact of 1.5%. The implementation of this new surcharge will coincide with when the Company begins incurring costs associated with its CEP. In addition, the Company is proposing to reduce the Renewable Energy Standard Adjustment ("RESA") surcharge from 2% down to 1% as discussed in the Company's Renewable Energy Standard Plan ("RES Plan"). Also, the Company's CEP provides additional long-term fuel savings which will reduce the Company's Energy Cost Adjustment surcharge.

Renewable Advantage (Turkey Creek Project)

On November 22, 2019, in light of favorable renewable energy market pricing and conditions, Black Hills filed an application to amend its ERP and conduct a targeted renewable energy resource solicitation known as Renewable Advantage.[2] The Company sought approval to add up to 200 MW of eligible renewable energy and/or storage resources through a competitive solicitation. On June 19, 2020, the Company filed its "120-Day Report," which identified as the winning bid a 200 MW solar project known as the Turkey Creek Project. On August 10, 2020, Black Hills filed an Unopposed Settlement Agreement and Joint Unopposed Motion to Approve Settlement Agreement, where, subject to a number of carefully negotiated

[2] *In Re Application of Black Hills Colorado Electric, LLC for Approval of an Amendment to its 2016 Electric Resource Plan Concerning a Competitive Solicitation for up to 200 MW of Renewable Energy and Energy Storage*, Proceeding No. 19A-0660E (filed Nov. 22, 2019).

parameters, Settling Parties agreed that the Company should be authorized to proceed with the power purchase agreement. On September 3, 2020, the assigned ALJ issued Decision No. R20-0647 approving the Settlement Agreement. The Recommended Decision became the decision of the Commission by operation of law. On February 19, 2021, the Company entered into a PPA to acquire the energy from the Turkey Creek Project.

However, TC Colorado Solar, LLC ("TC Colorado") provided the Company with a Notice of Termination of the PPA on January 31, 2022. On February 3, 2022, the Company responded to the notice, addressing (1) TC Colorado's previous requests for an extension of the commercial operation date, (2) Black Hills identification of a solution to allow the Turkey Creek Project to reach commercial operation upon terms agreeable to both parties, (3) disputing TC Colorado's right to terminate the PPA, and (4) requesting use of the dispute resolution process in the PPA to resolve these issues. Black Hills continued to negotiate with TC Colorado in good faith to determine if TC Colorado could deliver the project at a price that would be beneficial to customers. Citing broader issues in the market for solar photovoltaic materials, TC Colorado was unable to provide assurances it would be able to do so on the timeline Black Hills required for its prudent planning purposes. Thus the Company's Preferred Plan no longer includes the Turkey Creek Project.

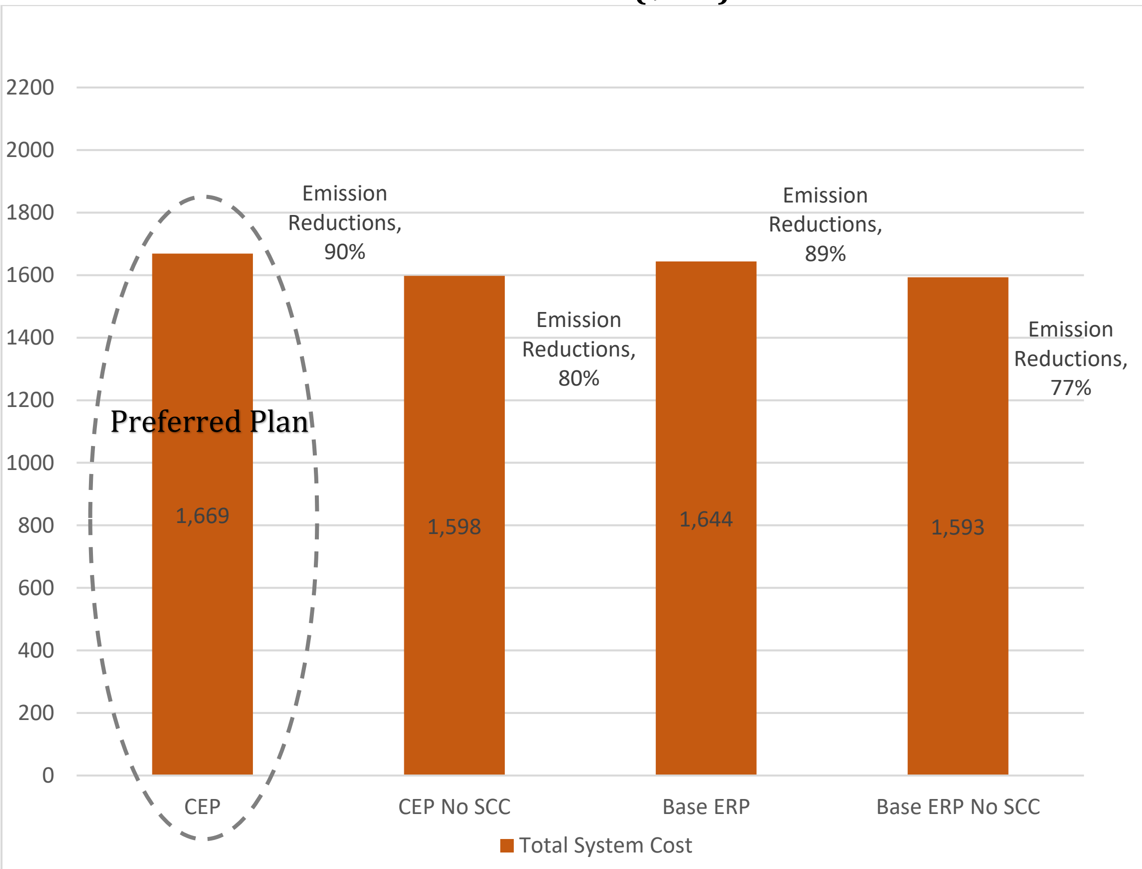
Scenario Analysis

To support thoughtful consideration of various pathways to achieve Colorado's emission reduction goals, the Company engaged in scenario analysis that derives various resource plans under different future conditions. In preparing the Plan, the Company prepared 23 such different scenarios. The scenarios include variations in inputs representing the significant sources of portfolio cost variability and risk. Notably included within these scenarios is a future driven by increased electrification efforts. In addition, for the first time in its resource planning process, the Company has applied values representing the social cost of carbon ("SCC") and the social cost of methane ("SCM"), consistent with legislation.[3] Other scenarios represent the following: high gas & low gas assumptions, with and without the Turkey Creek solar project, and a future optional 80 MW solar voluntary customer program.

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 2022-2050 Planning Period.

[3] 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 (2022-2050)
27 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 was 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 2030 Ready Plan pursuant to the Electric Resource Planning Rules, 4 CCR 723-3-3600 *et seq.* ("ERP Rules"). Traditionally, an Electric Resource Plan ("ERP") is intended to evaluate a utility's energy and capacity needs in light of its load forecasts, to achieve a "least cost" resource mix to serve customers. Uniquely, Black Hills' 2030 Ready Plan also contains the additional elements of a Clean Energy Plan ("CEP"), as set forth in Senate Bill 19-236 ("SB 19-236"), codified in § 40-2-125.5, 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) for the year 2050, or sooner if practicable, the Company is to seek to achieve the goal of providing energy generated from 100 percent clean energy resources, as long it is technically and economically feasible and in the public interest to do so. The 2030 Ready Plan thus represents a framework for addressing both the Commission's ERP requirements and the State's CEP requirements.

Black Hills is voluntarily submitting this 2030 Ready Plan pursuant to House Bill 19-1261 and Senate Bill 19-236. These complementary pieces of legislation establish emission reduction goals and regulatory requirements for the filing of a Clean Energy Plan. While Black Hills is not required by statute to file a clean energy plan, the Company's decision to file the 2030 Ready Plan is consistent with State policy, as well as its clean energy commitments to its customers. To assist the Company in preparing its 2030 Ready Plan, the Company is using new 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 2030 Ready Plan, including use of the RESOLVE and PLEXOS resource planning models.

Similar to a traditional ERP proceeding, the CEP will progress in two steps. The first step, otherwise known as Phase I, includes development of a load forecast, evaluation of the utility's current resources (including transmission), determination of need for additional resources, and the utility's proposed plan for acquiring the resources to meet the identified need. Phase I will include a litigated proceeding before the Commission, resulting in a final Commission decision on the process for evaluating resource bids in a competitive solicitation.

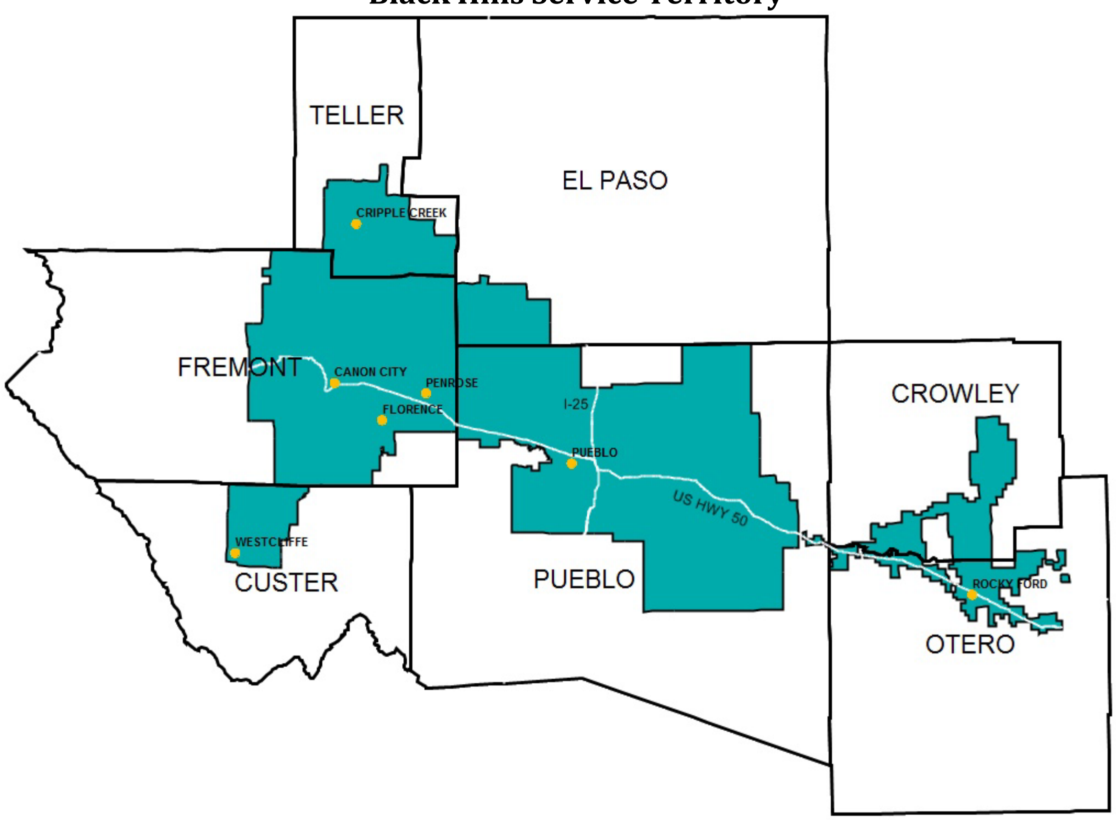
After receiving the Commission's Phase I decision, the Company will progress to the Phase II process. Phase II involves updating modeling inputs and assumptions consistent with the Commission's decision, and the Company's issuance of an RFP to govern a competitive solicitation, which is also overseen 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 comment on the Company's

120-Day Report, and it concludes with a Commission decision on the specific resources the Company is to acquire. The Phase I and Phase II processes are largely considered to represent industry best practices in resource planning and resource acquisition.

1.1 Background – Black Hills

Black Hills provides electric service to nearly 100,000 customers in 24 communities across Southern Colorado. In 2020, the Company sold more than 1,912 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 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 via purchases from the market as needed. The Company's generation portfolio includes:

- Pueblo Airport Generating Station ("PAGS") natural gas-fired generating units with a total capacity of 420 MW;
    - 200 MW combined-cycle turbines through a PPA with Black Hills Colorado IPP, which expires at the end of 2031.
    - 220 MW of utility owned simple-cycle generation.
- Three diesel stations with a total net capacity of 28 MW:
    - Rocky Ford diesel units are located in Rocky Ford, CO providing 10 MW of net capacity
    - Pueblo diesels, with a total of 8 MW of net capacity located in Pueblo, and,
    - Airport diesels, with a total of 10 MW of net capacity located in Pueblo
- The Busch Ranch Wind Project[4] in Huerfano County, a 29 MW wind resource which began commercial operation in 2012;
- The Busch Ranch II Wind Project[5], a 60 MW wind resource which entered commercial operation in 2019 in Huerfano County;
- The Peak View Wind Project, a 60 MW wind resource located in Huerfano County and Las Animas County, Colorado.
- An agreement with Missouri Public Service ("MPS") for delivery of up to 5 MW of capacity and energy between the western and eastern transmission grids, that terminates September 30, 2024.

The Company's power delivery system consists of approximately 598 miles of transmission and sub-transmission lines and 3,157 miles of distribution lines.

1.2 Overview of 2016 ERP and Renewable Advantage

The Company last filed an ERP, combined with its Renewable Energy Standard ("RES") Plan, with the Colorado Public Utilities Commission on June 3, 2016.[6] The Company's Preferred Plan did not require any additional capacity resources but included 60 MW of wind resources, which were largely needed to comply with the State's RES set forth in §40-2-124, C.R.S. *et seq*.

On November 10, 2016, Black Hills filed an Unopposed Settlement Agreement with respect to Phase I of its ERP, where, among other things, the Settling Parties agreed that the Company should move forward with a competitive RFP for 60 MW of renewable resources, and also agreed to the various inputs and assumptions that should apply during Phase II. On January 17, 2017, the assigned Administrative Law

[4] 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.
[5] The Company purchases the energy produced by the 60 MW turbines under a PPA that has a 25-year term.
[6] *In Re Application of Black Hills/Colorado Electric Utility Company, LP for (1) Approval of its 2016 Electric Resource Plan, and (2) Approval of its 2018-2021 RES Compliance Plan*, Proceeding No. 16A-0436E (Filed June 3, 2016).

Judge ("ALJ") issued Recommended Decision (R17-0039), which approved the Settlement Agreement and became the decision of the Commission by operation of law. Black Hills conducted its competitive RFP and on February 9, 2018 published its 120-Day Report recommending the Commission approve acquisition of the 60 MW Busch Ranch II wind facility. On June 14, 2018, the Commission issued its Phase II decision, Decision No. C18-0462, where it approved the Company's PPA for the 60 MW Busch Ranch II wind facility, which has since commenced commercial operation.

On November 22, 2019, in light of favorable renewable energy market pricing and conditions, Black Hills filed an application to amend its ERP and conduct a targeted renewable energy resource solicitation known as Renewable Advantage.[7] The Company sought approval to add up to 200 MW of eligible renewable energy and/or storage resources through a competitive solicitation. Consistent with the procedural schedule approved in the proceeding, on June 19, 2020, Black Hills filed its "120-Day Report," which identified as the winning bid a 200 MW solar project known as the Turkey Creek Project. On August 10, 2020, Black Hills filed an Unopposed Settlement Agreement and Joint Unopposed Motion to Approve Settlement Agreement, where, subject to a number of carefully negotiated parameters, Settling Parties agreed that the Company should be authorized to proceed with the PPA. On September 3, 2020, the assigned ALJ issued Decision No. R20-0647 approving the Settlement Agreement. The Recommended Decision became the decision of the Commission by operation of law. On February 19, 2021, the Company entered into a PPA to acquire the energy from the Turkey Creek Project.

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[7] *In Re Application of Black Hills Colorado Electric, LLC for Approval of an Amendment to its 2016 Electric Resource Plan Concerning a Competitive Solicitation for up to 200 MW of Renewable Energy and Energy Storage*, Proceeding No. 19A-0660E (filed Nov. 22, 2019).

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 2022 ERP planning cycle include:

- Plans and programs for demand-side management;
- Economic conditions globally and in Colorado, including commodity pricing and labor and supply chain constraints;
- 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 wind and solar project; 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 2022-2024 DSM plan. The Commission recently approved the Company's 2022-2024 DSM Plan in Proceeding No. 21A-0166E, however the Company was unable to update its modeling with the final approved amounts, rather the Company used the demand and savings amounts from its proposed amounts stemming from its direct testimony. The Company will incorporate the updated demand and energy savings goals from this recently approved DSM plan at the appropriate time in this proceeding.

2.2 Economic Conditions

According to the "Economic and Revenue Forecast" published by the Colorado Legislative Council Staff Economics Section, both the national and the state economic activity continue to recover from the pandemic-induced recession.[8] Recovery has been uneven with many households and businesses still bearing the brunt of the downturn while others have been unscathed or even better off. Spending and employment in sectors tied to in-person service continue to lag pre-pandemic levels. It is expected that 2022 will see inflationary pressures and challenging economic recovery as government assistance recedes.[9] Furthermore, the Consumer Price Index has increased by over 8 percent in the last 12 months[10], further supporting the inflationary pressures. In light of these inflationary pressures, the Company reserves the right to adjust the inflation factor (rate of escalation) used in the financial related parameters.

In addition, supply chain bottlenecks have placed challenges on the development of new generation facilities. For example, the U.S. Department of Commerce's ("DOC") March 28, 2022 announcement that it was pursuing an anti-dumping circumvention ("ADCV") investigation into solar cells imported from four Southeast Asian countries in response to a February petition filed by Auxin Solar.[11] In addition, high European demand for solar cells due to the war in Ukraine and global desires to minimize reliance on Russian fuel, are effecting the U.S. solar market.

The median household income in the Black Hills service territory is $47,813 which is $24,518, or 33%, less than the Colorado median of $72,331. The mean household income in the Company's service territory is $60,630, which is $36,340, or 37%, less than the Colorado mean of $96,970. In other words, according to the Census Bureau data, customers of the Company are living on nearly 62% of the average Colorado resident mean household income. This highlights the need for a thoughtful cost-effective transition to decarbonizing the Company's generation portfolio.

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[8] *2021 September Economic and Revenue Forecast*, Colorado Legislative Council Staff Economics Section, Colorado General Assembly Legislative Council Staff, available at: https://leg.colorado.gov/sites/default/files/images/lcs/septforecast_1.pdf

[9] Reuters, *IMF warns of "stagflationary" risks in Asia, cuts growth outlook* (Apr. 25, 2022), https://www.reuters.com/world/asia-pacific/imf-warns-asia-faces-stagflationary-economic-outlook-2022-04-26/?msclkid=3ae53b5dc51111eca717d57d4bd067de.

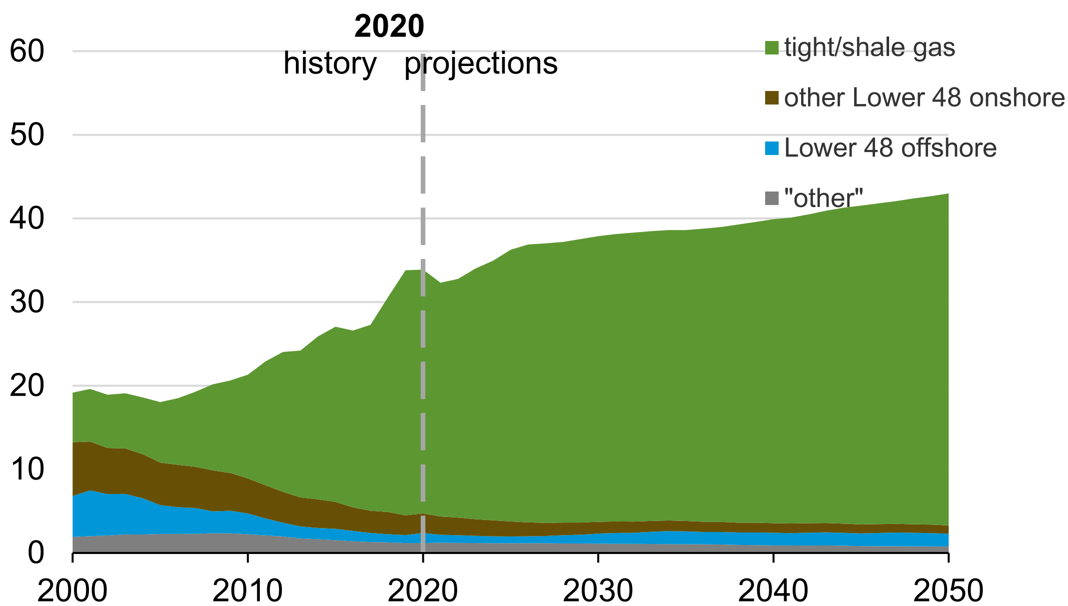
[10] https://www.bls.gov/news.release/cpi.nr0.htm

[11] *See* https://www.utilitydive.com/news/solar-panel-assembler-files-petition-seeking-antidumping-review-of-southeas/618622/.

2.3 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, 2000-2050
(trillion cubic feet per year)

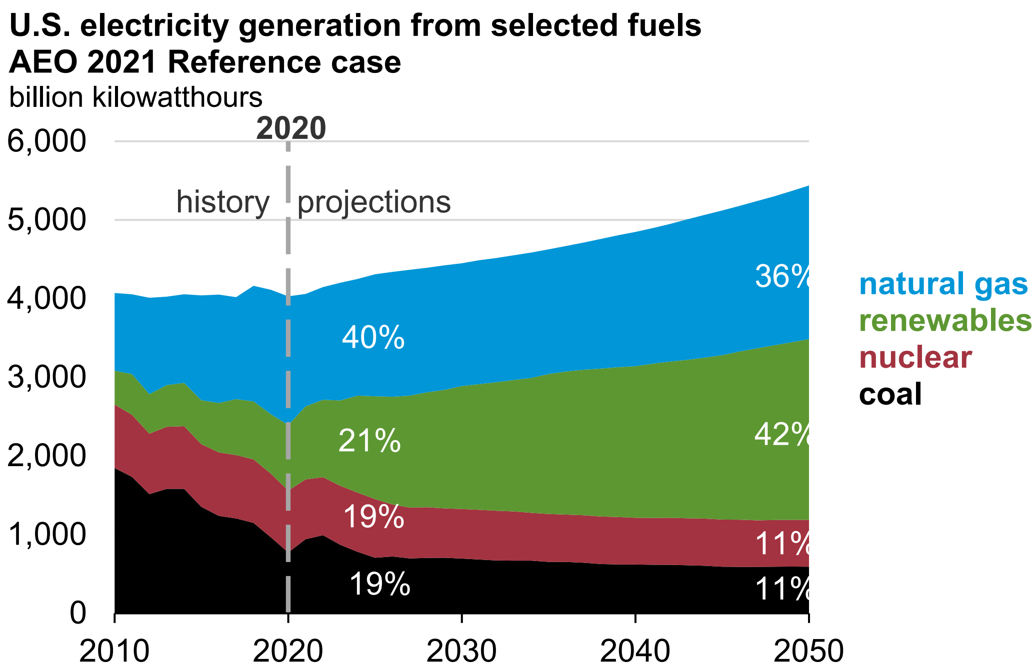


Source: US Energy Information Administration, Annual Energy Outlook 2021

As a result of Environmental Protection Agency ("EPA") regulation, specifically EPA's Regional Haze rule, to limit emissions from stationary sources, many electric generation owners continue to close or convert older, inefficient coal plants. Renewable 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. Over the next few years, natural gas generation is expected to decrease as a result of generation owners taking advantage of the production tax credit and investment tax credit available to renewable generation investments. 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 2021 Annual Energy Outlook[12].

[12] https://www.eia.gov/outlooks/aeo/pdf/00%20AEO2021%20Chart%20Library.pdf

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



Source: US Energy Information Administration, Annual Energy Outlook 2021

2.4 Environmental Regulations

The EPA has been active since 2009 with regard to 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.

2.4.1 Regional Haze Regulation

In Phase I and II Regional Haze planning periods, EPA and states have focused on coal-fired generating facilities. Since Black Hills does not have coal-fired generation, it has not been impacted by the Regional Haze Rule. The Company's natural gas fleet could be impacted in future planning periods, as they generate air pollutants that could contribute to Regional Haze and Colorado may require controls in the future to address these emissions.

2.4.2 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 finalized on February 16, 2012.

2.4.3 Federal Greenhouse Gas Regulation

Since January 2, 2011, the EPA has been regulating greenhouse gas ("GHG") emissions from the largest stationary sources through the Prevention of Significant Deterioration ("PSD") and Title V Operating Permit Programs. GHGs are comprised of six gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.[13] 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, SO2, NOx, 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 CO2 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.

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[13] Clean Air Act Permitting for Greenhouse Gases, U.S. Environmental Protection Agency, http://www.epa.gov/nsr/ghgpermitting.html.

2.4.4 Environmental Protection Agency's Clean Power Plan ("CPP")

The EPA proposed the Clean Power Plan ("CPP") on June 2, 2014. The final CPP rule was issued on August 3, 2015, published in the Federal Register on October 23, 2015 and became effective on December 22, 2015. The final CPP set specific CO_2 emission reduction goals for State's and a national CO_2 emission reduction goal that equates to a 32 percent reduction by 2030, using 2005 emission levels as a baseline. On June 19, 2019, the CPP was repealed and replaced with the Affordable Clean Energy rule (ACE). At this time, EPA has not taken concrete action to propose GHG rules.

2.4.5 Colorado's Emission Reduction Statutes

In the 2019 legislative session, Colorado passed House Bill 19-1261 and Senate Bill 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 utility emission reductions through CEP filings. 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 ("AQCC") 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. 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.

2.4.6 Clean Energy Plan Guidance

The Air Pollution Control Division ("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.[14] 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 a 90% 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.

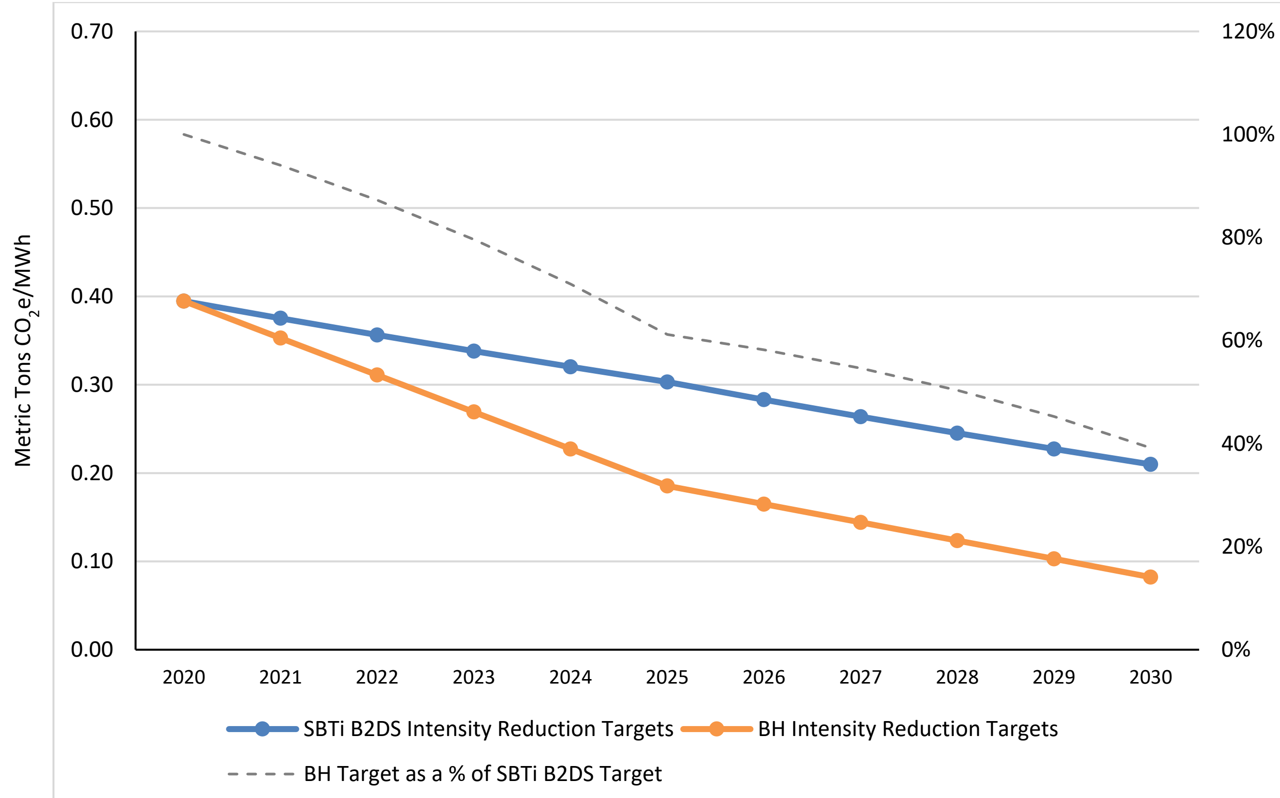
2.4.7 Preferred Plan SBTi Target Alignment

The Company utilized a third-party consultant to assess the alignment of the Preferred Plan's projected owned generation and purchased power greenhouse gas (GHG) emissions with the Science Based Targets initiative (SBTi)'s Below 2 Degree Scenario (B2DS)[15] and 1.5 Degree Scenario (1.5DS). The SBTi drives ambitious climate action across the public and private sectors by enabling organizations to set science-based emission reduction targets. Science-based targets provide companies with a clearly defined path to reduce emissions in line with the Paris Agreement goals. In the Paris Agreement, national governments committed to limit temperature rise to well-below 2 degrees Celsius (°C) and pursue efforts to limit temperature rise to 1.5°C. The SBTi guidance establishes GHG reduction requirements to align with the well-below 2°C scenario (B2DS) and 1.5°C scenario (1.5DS).

SBTi guidance for the Power Sector and Company base year 2020 data was utilized to calculate generation related emissions allowed based on generation to achieve alignment with B2DS and 1.5DS targets. Projected 2030 emissions for the Preferred Plan were calculated using the CEP Guidance and verification workbook and were plotted against the SBTi scenario's allowed generation related emissions for the same year. The results demonstrate that the Company's Preferred Plan is in alignment with both the B2DS (Figure 2-3) and 1.5DS (Figure 2-4) by 2030.

[14] Available at https://cdphe.colorado.gov/air-pollution/climate-change#Energy.
[15] SBTi plans to phase out the use of B2DS targets as of July 15, 2022 (press release) and move towards 1.5DS targets only. In order to assess Black Hills operational changes as comprehensively as possible, we completed all of our target alignment analyses utilizing both B2DS and 1.5DS targets.

Figure 2-3
SBTi-aligned B2DS Targets – Clean Energy Plan



Key Assumptions	
Approach	Sectoral Decarbonization
Industry	Power
Scenario	Energy Technology Perspectives' (ETP) "Beyond 2 Degree Scenario" (B2DS)
Boundaries	Scope 1 & Partial Scope 3 Purchased Power (Electric Only)

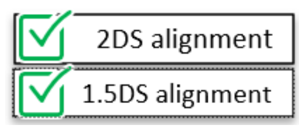
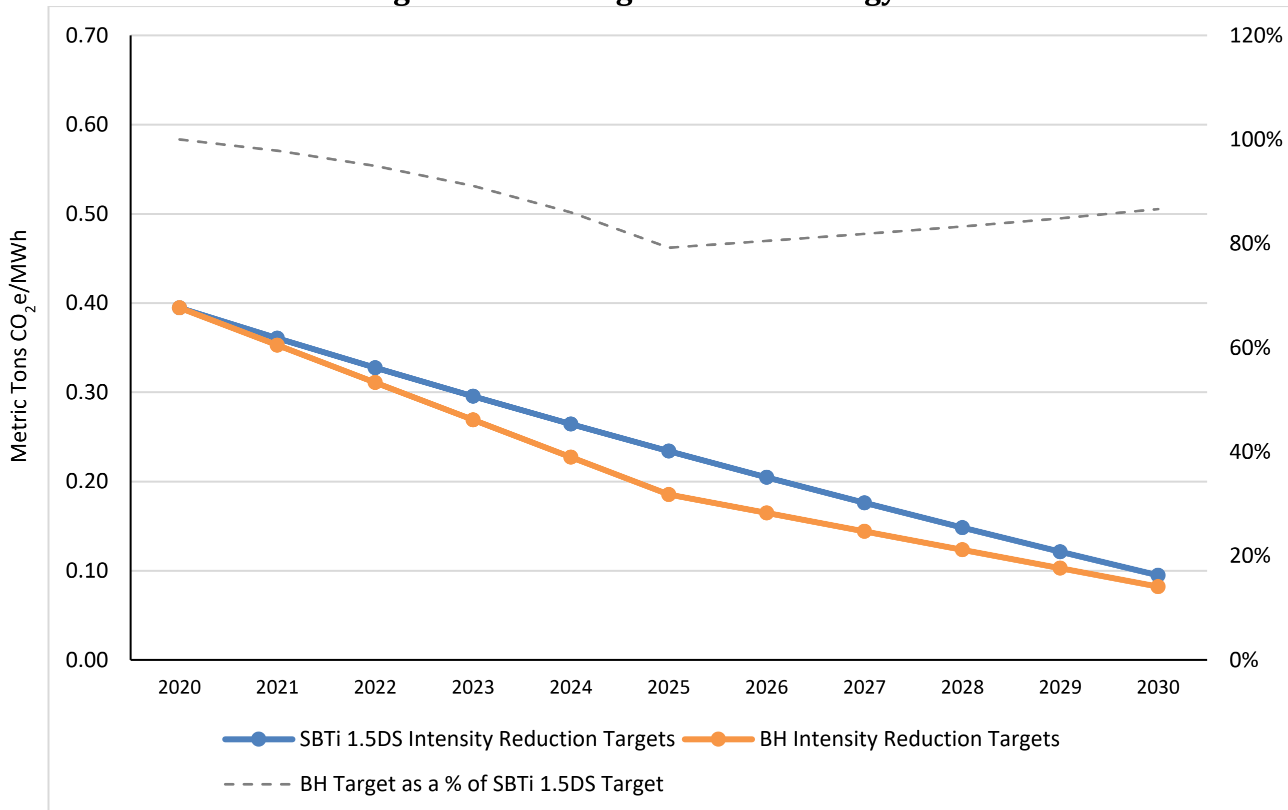


Figure 2-4
SBTi-aligned 1.5DS Targets – Clean Energy Plan



Key Assumptions	
Approach	Sectoral Decarbonization
Industry	Power
Scenario	Energy Technology Perspectives' (ETP) "1.5 Degree Scenario" (1.5DS)
Boundaries	Scope 1 & Partial Scope 3 Purchased Power (Electric Only)

☑ 2DS alignment

☑ 1.5DS alignment

2.4.8 Colorado GHG Pollution Reduction Roadmap

In January 2021, Colorado issued the Colorado Greenhouse Gas Pollution Reduction Roadmap ("Roadmap").[16] The Roadmap includes a vision to advance emission reductions across the economy, with sector-specific emission regulations that take into account the nature of the diverse segments of the economy regulated under any program. The Roadmap supports utilities achieving an 80% reduction of emissions below 2005 emissions by 2030. The Roadmap is thus supportive of the CEP emission reduction targets.

2.4.9 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, the Preferred Plan and several other scenarios include the social cost of emissions. To assist consideration of the impacts of these social costs, the Company is also providing scenarios that exclude the social costs, providing a spectrum of impacts resulting from the inclusion of the externalities into generation portfolio optimization.

2.5 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 following year.

Additionally, Black Hills must 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.

Black Hills is concurrently filing its updated RES Plan with this CEP. The CEP and RES plans are closely aligned and complement each other. The Company's RES Plan demonstrates that it will be in compliance with the requirements set forth in § 40-2-124, C.R.S.

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[16] *See* Colorado Greenhouse Gas Pollution Reduction Roadmap (Jan. 14, 2021), available at https://energyoffice.colorado.gov/climate-energy/ghg-pollution-reduction-roadmap.

2.6 Federal Tax Incentives for Wind and Solar Projects

In 2020, Congress passed the Consolidated Appropriations Act, 2021. This Act extended the in-service date when wind and solar facilities need to be placed in service from end-of-year 2024 to end-of-year 2025. Wind and solar facilities placed in-service by December 31, 2025 can qualify for 60 percent PTC and 26 percent ITC, respectively, so long as the project has commenced construction before January 1, 2022 for the wind PTC and before January 1, 2023 for the solar ITC. The Company is actively monitoring whether Congress will extend the PTC or ITC. At present, though, wind PTC is no longer available for new facilities constructed after 2021. The solar ITC begins phasing down for projects beginning construction after 2022. For solar projects that begin construction in 2023, and are placed in service before the end of 2025, a 22 percent ITC applies. For solar projects that begin construction after 2023, or for projects that are not placed in service by the end of 2025, a 10 percent ITC applies.

2.7 The Power Supply Market

Power market transactions yield two main economic efficiencies. They assure that resources with the lowest operating cost are serving 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 substantial 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.

Black Hills participates in a joint dispatch agreement ("JDA") with Public Service Company of Colorado, Colorado Springs Utilities, and Platte River Power Authority. This agreement allows for non-firm energy purchases and sales based on the cost of generation of other resources participating in the JDA. In the event Black Hills' resources have a higher cost to generate then the marginal JDA unit, the Company can back its units down and serve load with the less expensive JDA energy. Alternatively, if Black Hills' resources have a lower cost to generate then the marginal JDA unit, the Company can generate more than its obligation and receive compensation for that sale, benefiting customers.

Beyond the JDA, Senate Bill 21-072 requires that Colorado transmission utilities join an Organized Wholesale Market (as defined in statute) on or before Jan. 1, 2030, subject to certain conditions and exceptions. In furtherance of this requirement, on

January 25, 2022, Black Hills announced plans to join the Western Energy Imbalance Service ("WEIS") operated by the Southwest Power Pool ("SPP"). Benefits from joining the WEIS may include improved efficiencies in operations of the system that can reduce energy costs and assist in integrating renewable resources. Black Hills expects to begin participation in the WEIS in April 2023. In addition, Black Hills and other western U.S. electric utilities are exploring regional market solutions through a newly formed group, Western Markets Exploratory Group ("WMEG"). Although the Company does not anticipate any of these market developments will impact this ERP filing, for informational purposes, the Company has modeled a Organized Wholesale Market ("OWM") scenario where it substantially increased the amount of economy energy purchases and added an energy sales market assumption. The OWM scenario is discussed in more detail in Section 3.5.4 below.

3.0 Clean Energy Plan Key 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 new 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 Plan, including use of the RESOLVE and 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 29 years for this Plan, which covers the period 2022 through 2050. Twenty-nine 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.

3.2 Resource Acquisition Period

The RAP covers the timeframe of 2022-2030. The Company used this period because SB 19-236 directs CEPs to use a RAP through 2030. The selected RAP provides adequate time for the acquisition of the necessary resources to meet our customers' resource needs. For its capacity expansion modeling, the Company selected 2025 as the earliest a new resource could come on-line. During the Phase II competitive acquisition process the Company expects developers to bid projects with Commercial Operation Dates ("COD") between 2025 and 2030.

3.3 Planning Reserve Margin

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 an unforeseen loss of generating resources, extreme weather, or other unexpected conditions.

For purposes of this Plan, the Company has updated its planning reserve margin from 15 percent to 24 percent based upon the Planning Reserve Margin study that was completed by E3. The planning reserve margin ensures that, if satisfied, the Black Hills Colorado system will continue to operate reliably. The Planning Reserve Margin study utilized a 1-day-in-10-year reliability target for 2030. The 1-day-in-10-year reliability target means that, on average, there can only be one day with outage events every ten years and that corresponds to a 0.1 Loss of Load Expectation ("LOLE"). The details of this study can be found in Appendix F. A 24 percent reserve margin is appropriate given the relatively small size of the Company's system. The Company's peak load requirement is expected to be approximately 435 MW in 2022, and its largest single hazard is 100 MW. As part of the Company's Subentity Reserve Sharing Agreement with Public Service Company of Colorado ("PSCo"), the Company has the ability to call on Reserve Energy for up to 60 minutes after a qualifying event for any of its generating units. Thereafter, the Company is required to replace the lost capacity.

The 24 percent reserve margin was used for each of the base, high, low, and increased electrification load forecasts. The Company will acquire, through the Phase II process, generation resources as necessary to achieve, at a minimum, the reserve margin throughout the RAP.

The Company's relatively small system size in conjunction with the single largest contingency generation unit contributes to the increase in planning reserve margin. The increase to the planning reserve margin is not unique to the Company. The Western Electricity Coordinating Council ("WECC") is the Regional Entity responsible for ensuring western interconnection compliance with the North

American Electric Reliability Corporation's (NERC") Reliability Standards. Black Hills is specifically within the NWPP Central ("NWPP-C") subregion of WECC. In December 2021, WECC released its Western Assessment of Resource Adequacy. In this assessment, WECC identified the potential for electricity supply shortages using probabilistic analysis at the hourly level, and it reported its findings for the following 4-year period. For the NWPP-C subregion, the Western Assessment found that by 2025 a planning reserve margin of 20.3% maintained resource adequacy for load loss to remain 99.98 percent reliable. According to this assessment, the NWPP-C subregion does not have enough resources to maintain resource adequacy for all hours and requires imports from other subregions.

3.4 Fuel and Market Prices

The fuel price assumptions used in the Plan were based on the Hitachi ABB Power Grids ("HAPG") WECC 2021 Spring Reference Case. This is a confidential, proprietary product which can be purchased from HAPG. In order to protect HAPG from public disclosure of its proprietary product, the details of the HAPG fuel price forecasts are set forth in the Appendix M.

3.4.1 Natural Gas Prices

The Company used the natural gas price forecast for Colorado from HAPG's WECC 2021 Spring Reference Case for both existing and future natural gas-fired resources. Basis differential and transportation costs were added to HAPG's Colorado forecast to reflect the delivered price of natural gas. Table 3-1 below shows the price ranges of Colorado natural gas prices from 2022 through 2050 for the Base ERP and scenarios completed for the Plan. The natural gas price forecast used in the modeling is included in Schedules M-3, M-7, and M-10, Appendix M.

Table 3-1
Average Annual Gas Price ($2021/MMBtu)[17]

	Colorado		
Scenario	**2022**	**2030**	**2050**
Base Gas	$3.43	$4.13	$6.44
High Gas	$4.73	$5.92	$8.58
Low Gas	$3.02	$3.32	$4.45

In developing the Low Gas and High Gas price scenarios, HAPG used a comprehensive methodology in their approach. HAPG's methodology for the Low Gas and High Gas price scenarios isolates the impact of supply expectations on natural gas prices by holding other natural gas and power assumptions constant. In

[17] From HAPG 2021 Spring Power Reference Case; for exclusive use in Black Hills 2022 ERP and CEP Report

the low gas price case, HAPG set production costs equal to the short run marginal cost throughout the forecast timeframe. Over the long-term, significant additional technological improvements would be required to sustain the price trajectory in this scenario. HAPG assumes that the long-run marginal production costs for shale plays are increased to at least the 75th percentile in the High Gas price scenario and shale resources are approximately 15 percent lower than in the base case.

3.4.2 Oil Prices

The oil price forecast from HAPG's WECC 2021 Spring Reference Case for diesel was used for the oil price forecast and is shown in Schedule M-4, Appendix M. Table 3-2 below shows the average oil prices for years 2022 and 2050.

Table 3-2
Average Annual Oil Price ($2021/MMBtu)[18]

	No. 2 (Distillate) Price)		
Scenario	**2022**	**2030**	**2050**
Base Diesel	$11.34	13.53	$16.54

3.4.3 Hydrogen Prices

The hydrogen price forecast was developed by E3 for the Base Hydrogen and Low Hydrogen scenarios. The hydrogen price forecasts are shown in Table 3-3, and they are further available in Appendix F.

Table 3-3
Average Annual Hydrogen Price ($2021/MMBtu)

Scenario	2025	2030	2050
Base Hydrogen	$29.50	$26.62	$15.11
Low Hydrogen	$25.40	$21.82	$ 7.46

3.4.4 Economy Energy Prices

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

[18] From HAPG 2021 Spring Power Reference Case; for exclusive use in Black Hills 2022 ERP and CEP Report

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 from two market areas. The Colorado-East market area allowed up to 50 MW and the Palo Verde market area allowed up to 50 MW each hour. No sales markets were available. Table 3-4 below shows the price ranges of each market area from the beginning and ending years of the Planning Period for the Base ERP Plan and scenarios completed for the Plan.

In addition, to assist consideration of the impacts of potential organized wholesale market participation, the Company completed an OWM scenario. This model was allowed to purchase up to 200 MW of economy energy every hour from the two market areas, essentially doubling the quantities described above. This OWM scenario was allowed to sell up to 100 MW of economy energy sales every hour to the Palo Verde market area.

The market area price forecasts are included in Schedules M-1, M-5, and M-8, Appendix M. These price forecasts are based on the HAPG 2021 Spring Reference Case.

Table 3-4
Average Annual Economy Energy Price Forecasts[19]

Scenario	**CO-East**	**CO-East**	**CO-East**	**Palo Verde**	**Palo Verde**	**Palo Verde**
	2022 Price ($/MWh)	**2030 Price ($/MWh)**	**2050 Price ($/MWh)**	**2022 Price ($/MWh)**	**2030 Price ($/MWh)**	**2050 Price ($/MWh)**
Base Natural Gas	$21.23	$30.94	$47.32	$29.63	$31.90	$54.61
High Natural Gas	$24.16	$35.36	$53.61	$39.58	$42.83	$70.77
Low Natural Gas	$20.46	$25.76	$33.78	$27.99	$27.17	$40.65

[19] From HAPG 2021 Spring Power Reference Case; for exclusive use in Black Hills 2022 ERP and CEP Report

3.4.5 Seasonal Firm Market Purchase Prices

Seasonal firm market purchases are blocks of energy that are available for purchase with firm transmission. These purchases are made in lieu of procuring an additional resource and can be an option utilized for short term capacity needs to help manage customer costs. The Company used the HAPG 2021 Spring Reference Case energy price forecast for the Palo Verde, Arizona market area plus a 20 percent premium and transmission adder, as a proxy for seasonal firm market purchases. Seasonal firm market purchases were assumed to be 10 MW blocks up to 50 MW through the Planning Period. In establishing these assumptions, the Company considered both the capacity in the region and capacity import limitations specific to the Company's system. The 10 MW block size was selected based on the minimum size of the blocks of power typically available for this type of product. Seasonal firm market purchases were assumed for 16 hours per day six days a week. Table 3-5 below shows the price ranges of each market area from the beginning and ending years of the Planning Period for the Base ERP and scenarios completed. The base Palo Verde, Arizona price forecast used is included in Schedules M-2, M-6, and M-9, Appendix M.

Table 3-5
Seasonal Firm Market Purchase Price Forecasts[20]

Scenario	Palo Verde 2022 Price ($/MWh)	Palo Verde 2030 Price ($/MWh)	Palo Verde 2050 Price ($/MWh)
Base Natural Gas	$29.63	$31.90	$54.61
High Natural Gas	$39.58	$42.83	$70.77
Low Natural Gas	$27.99	$27.17	$40.65

3.5 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 3-6 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. Tax lives of 20 years were used for hydrogen-ready gas combustion turbines and nuclear small modular reactors. A five-year tax life was used for solar,

[20] From HAPG 2021 Spring Power Reference Case; for exclusive use in Black Hills 2022 ERP and CEP Report

wind, and geothermal. A seven-year tax life was used for 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. 16AL-0326E).

Table 3-6
Financial Parameters

Component	Annual Rate (percent)
Cost of Debt	5.29
Equity	9.37
Weighted-Average Cost of Capital (WACC After-tax[21])	6.81
Income Tax Rate	24.595
Rate of Escalation[22]	1.5
Capital Structure	
Equity Debt	52.39 47.61
Property Tax Rate	1.07
Solar 2030 fixed charge rate (30-year)	5.98
Wind 2030 fixed charge rate (30-year)	6.36
Storage 2030 fixed charge rate (30-year)	8.73
Geothermal 2030 fixed charge rate (30-year)	7.53
Gas 2030 fixed charge rate (30-year)	8.14
Nuclear SMR 2030 fixed charge rate (30-year)	7.37

3.6 Social Cost of Emissions

The social cost of carbon ("SCC") and social cost of methane ("SCM") 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. The Company also applied the SCM to fugitive methane leaks from the upstream PAGS gas pipeline owned by Black Hills Colorado Electric, LLC and Black Hills Colorado IPP, LLC. Section 8.6 provides a detailed description of which scenarios include these emissions costs. The specific values

[21] The after-tax cost of capital was calculated based on the pre-tax cost of capital approved in the most recent rate review of 7.43%
[22] 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.

used for the social costs of emissions is provided in Table 3-7, and these are from the Interagency Working Group's ("IWG") Technical Support Document ("TSD").[23]

Table 3-7
Annual Social Cost of Carbon and Methane Price ($/Short Ton)

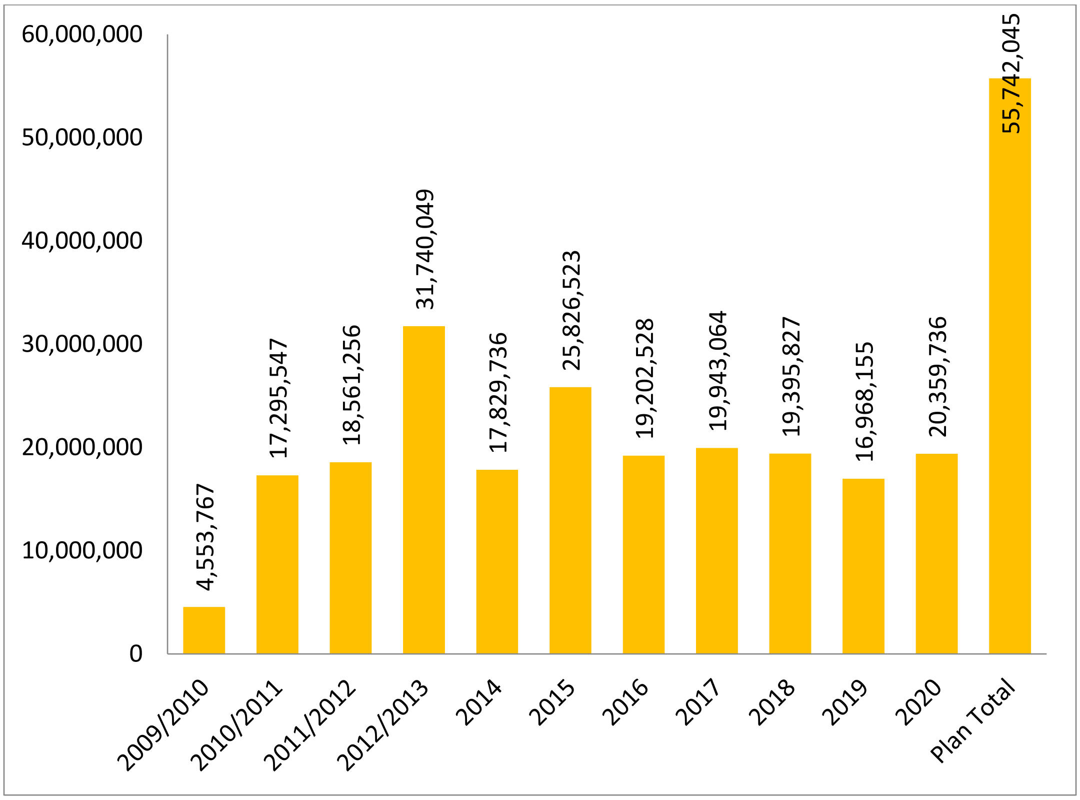
Year	SCC	SCM
2020	$68.0	
2021	$69.0	$1,756
2022	$70.1	$1,782
2023	$71.1	$1,809
2024	$72.2	$1,836
2025	$73.3	$1,864
2026	$74.4	$1,892
2027	$75.5	$1,920
2028	$76.6	$1,949
2029	$77.8	$1,978
2030	$78.9	$2,008
2031	$80.1	$2,038
2032	$81.3	$2,068
2033	$82.5	$2,100
2034	$83.8	$2,131
2035	$85.0	$2,163
2036	$86.3	$2,195
2037	$87.6	$2,228
2038	$88.9	$2,262
2039	$90.2	$2,296
2040	$91.6	$2,330
2041	$93.0	$2,365
2042	$94.4	$2,401
2043	$95.8	$2,437
2044	$97.2	$2,473
2045	$98.7	$2,510
2046	$100.1	$2,548
2047	$101.6	$2,586
2048	$103.2	$2,625
2049	$104.7	$2,664
2050	$106.3	$2,704

[23] 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.

3.7 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 2020.

Figure 3-1
2009 – 2020 Energy Efficiency Savings (kWh)



Black Hills filed for approval of its 2022-2024 Electric DSM Plan for calendar years 2022, 2023 and 2024 on April 30, 2021 in Proceeding No. 21A-0166E. The Commission deliberated on April 6, 2022 and approved the ALJ Recommended Decision No. R21-0790, approving average energy savings goals of approximately 18.5 GWh (at the meter) per year and an annual average demand (kW) savings goal of approximately 4,380 kW. A written Commission Decision Addressing Exceptions to Recommended Decision No. R21-0790 was mailed on May 5, 2022. These amounts differ slightly from the Company's original proposed savings amounts are presented in its Direct Testimony.

The load forecast developed for this proceeding was reduced by the projected savings filed in the Company's direct case in its 2022-2024 DSM Plan shown in Table 3-8. Since the Company only recently received Commission approval of its new DSM

Plan, the Company was not able to update its DSM planning assumptions with the final approved demand and energy savings amounts. The Company will however update this planning assumption with the final DSM demand and energy savings amounts at the appropriate time in this proceeding. Table 3-8 below provides the demand and energy savings amounts used in the Plan modeling. Table 3-9 below provides the final Commission-approved demand and energy savings goals.

Table 3-8
DSM Assumptions used

	Projected Peak Savings (MW)	Projected Energy Savings (MWh)
Plan Year 1 - 2022	3.82	16,822
Plan Year 2 - 2023	3.90	17,381
Plan Year 3 - 2024	3.96	17,652

Table 3-9
Updated DSM Assumptions to be used

	Projected Peak Savings (MW)	Projected Energy Savings (MWh)
Plan Year 1 – 2022	4.11	18,292
Plan Year 2 – 2023	4.33	18,416
Plan Year 3 – 2024	4.71	18,685

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 3-10.

Table 3-10
Adjustments to Load Forecast for DSM

Year	Projected Peak Savings (MW)*	Projected Energy Savings (MWh)**
2022	7.4	42,722
2023	11.3	60,103
2024	15.2	77,755
2025	16.9	77,755
2026	16.9	77,755
2027	16.9	77,755
2028	16.9	77,755
2029	16.9	77,755
2030	16.9	77,755
2031	16.9	77,755
2032	16.9	77,755
2033	16.9	77,755
2034	16.9	77,755
2035	16.9	77,755
2036	16.9	77,755
2037	16.9	77,755
2038	16.9	77,755
2039	16.9	77,755
2040	16.9	77,755
2041	16.9	77,755
2042	16.9	77,755
2043	16.9	77,755
2044	16.9	77,755
2045	16.9	77,755
2046	16.9	77,755
2047	16.9	77,755
2048	16.9	77,755
2049	16.9	77,755
2050	16.9	77,755

*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 system-level monthly peak demand forecast was computed by adding large customer loads, including anticipated future load growth, the effects of DSM plans, and a net behind-the-meter ("BTM") solar forecast to the base load forecast produced from the regression analysis. The final system-level major customer class energy forecasts were computed by adding large customer loads, including their anticipated future load growth, losses, the effects of DSM plans, and a net BTM solar forecast to the base energy forecasts calculated through the regression analysis.

The Plan developed base, low, high, and increased electrification load forecasts, and includes system-level demand and major customer class energy forecasts using historical data.

4.1 Econometric Model Overview

Econometric modeling was used as the foundation for system level demand and major customer class 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 customer sales, the number of customers served, and system 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 sales (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 sales (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., sales) are then applied to forecasts of the drivers to develop the forecast sales, 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 system-level hourly load data to develop the peak demand forecast. The Company identified one individual large customer whose load was removed from the historical load data before modeling. The Company excluded this customer's load from the historical data because it is a significant percentage of the Company's total load and is not expected to increase. Therefore, the Company did not want the growth rates calculated through the regression analysis applied to this large load. Black Hills subtracted this large customer's hourly peak data from the system historical data, creating a new "base" historical dataset. This "base" historical dataset was used in the regression analysis. The excluded data for the one large customer was added back into the demand forecast after the model runs were complete. Similarly, historical net BTM solar load was removed prior to modeling and was added back into the demand forecast after the model runs were complete.

The major customer class energy forecasts were developed using historic sales and customer count. Sales data by rate identification were gathered, reviewed, and aggregated into major customer classes based on the type of service (for example, residential, commercial, and industrial) as appropriate. Similar to the hourly load data, a base historical sales dataset was established by removing specific large customers and historical net BTM solar data. In addition, historical lighting service data and Company-usage data were removed before conducting the sales forecast regression analysis to ensure the customer class sales growth rates were not skewed by the historical growth patterns for these sectors. The excluded data for certain large customers, BTM solar load, lighting, and Company use were added to the aggregated sales forecast after the major class forecast regressions were complete.

The historical load and sales data used in the peak demand and sales models is included in Schedule B-1 and Schedule B-2, 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 2050. 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, gross regional product ("GRP"), and total personal income per-capita. Each of these variables was tested in the regression analysis.

The historical and forecasted economic data used in the peak demand and sales models are included in Schedule B-3, Appendix B.

4.2.3 Weather Data

Historical weather data was collected from the 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. The historical weather data used in the peak demand and sales models is included in Schedule B-4 and Schedule B-5, Appendix B respectively.

4.2.4 Normal Weather Conditions

The weather variables in the energy and demand forecasts are set to reflect "normal" conditions, which is interpreted as the average weather conditions over 20 years. In the energy model, the average of the sum of the cooling degree days over the available time period was used to calculate normal weather for each month. In the peak demand model, each month is determined to be either a predominantly cooling- or heating-peak month, and then only the relevant peak-hours for each month and year are averaged. Those averages are averaged again for each month and used as normalized peak weather conditions.

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., sales increase with CDDs) and statistically significant (or approaching statistical significance). Normal weather conditions are used to forecast energy and demand.

4.3.1 Peak Demand Forecast Methodology

The Company's system demand forecast is a system-level forecast inclusive of residential, commercial, industrial, and lighting sectors. Each month's peak hours from 2006 to 2020 were used to model the monthly peak demand forecast. The peak demand model was estimated using Ordinary Least Squares ("OLS"). The resulting estimates were used in combination with normal weather and forecasted economic conditions to forecast peak demands.

Summaries of the final equations, historical and forecasted values of variables used, and resulting forecasts for the demand model are provided in Schedules B-6 through B-9, Appendix B.

4.3.2 Energy Forecast Methodology

To complete the energy forecast, the Black Hills system was disaggregated into four major customer classes: residential, commercial small general service, commercial large general service, and industrial large power service. The residential customer class is an aggregation of all of Black Hills' residential rate identifications ("rate IDs"). The commercial classes include Black Hills' small and large general service rate IDs, and the Company's large power service rate IDs constitute the industrial class.

Summaries of the final equations, historical and forecasted values of variables used, and resulting forecasts for the energy models are provided in Schedules B-8 through B-25, Appendix B.

4.3.3 Solar Distributed Generation

Net BTM solar amounts represent the forecasted customer's total usage less the customer's generated solar. To complete the net BTM solar demand forecast, a piece-wise growth rate was calculated using 2014-2020 historical hourly net BTM data, the Company's system load shape, and anticipated growth of future ITC adoption rates. This growth rate was applied to the previously excluded solar demand data to forecast forward.

To complete the net BTM solar energy forecast, previously excluded solar load was used to develop customer count and class-level UPC forecasts. The residential, small general service, and large general service customer models were estimated using a traditional OLS approach, similar to the base energy forecast. The class-level UPC models were estimated using historical growth rate trends from 2006 through 2020. The customer count and UPC forecasts were multiplied together to produce the annual net-meter solar energy forecasts. These forecasts are then allocated across the 12 monthly periods in line with the expected solar irradiation levels across the geographic service territory. The Large Power Service net-meter solar energy forecast was produced by holding 2020 actual energy levels constant.

A detailed summary of the net BTM solar forecast, including the resulting demand and energy forecasts, are described in Appendix C.

4.3.4 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 2022 through 2030. 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. These annual changes in large customer loads are reflected in the peak demand and energy load forecasts.

Table 4-1
Large Customer Load Additions and Reductions 2022 - 2030

Customer	Load Factor	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)	2027 (MW)	2028 (MW)	2029 (MW)	2030 (MW)
Large Customer A	87%	1.0	0.0	-5.3	0.0	0.0	0.0	0.0	0.0	0.0
Large Customer B	32%	0.0	0.0	1.5	0.0	0.0	0.0	0.0	0.0	0.0
Large Customer C	50%	1.5	0.5	0.3	0.3	0.0	0.0	0.0	0.0	0.0
Large Customer D	50%	2.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Large Customer E	45%	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

4.4 Base Peak Demand and Annual Energy Forecasts

The final base system-level monthly peak demand forecast was computed by adding the one large customer and anticipated future load growth of other large customers into the load forecast calculated by the regression analysis. Effects of DSM and the net BTM solar demand forecast were also added into the load forecast.

The final system-level major customer class energy forecasts were computed by adding large customer loads, including their anticipated future load growth, lighting service, Company-use, effects of DSM, transmission and distribution losses, and the net BTM solar energy forecast to the energy forecasts calculated through the regression analysis.

Combined transmission and distribution losses were also added into the annual energy forecast for each major customer class. 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. Separate system loss estimates cannot be made for transmission and distribution because the forecast was not developed at the transmission and distribution voltage level. The peak demand and energy forecast values for the base load forecast are shown in Table 4-3.

Table 4-2
Combined Transmission and Distribution Losses

Major Sales Class	Line Loss Class	Average Estimated Losses	Aggregated Customer Class Weighted Losses by Class	Non-aggregated Customer Class Sales Losses
Residential	Residential	5.506%		5.506%
Commercial	Large General Service - Primary	3.765%	5.352%	
	Large General Service - Secondary	5.506%		
	Small General Service	5.506%		
Industrial	Large Power Service - Primary	3.765%	3.820%	
	Large Power Service - Secondary	5.506%		
	Large Power Service - Transmission	2.210%		
Large Customer 1	Large Customer 1	3.765%		3.765%
Large Customer 2	Large Customer 2	3.765%		3.765%
Large Customer 3	Large Customer 3	2.210%		2.210%
Lighting		5.506%		5.506%
Company Use		5.506%		5.506%
Auxiliary	Total System		3.100%	
	Station Use			

Table 4-3
Base Load Forecast

Year	Peak Demand* (MW)	Annual Energy* (MWh)	Losses (MWh)
2022	435.5	2,111,958	151,869
2023	441.7	2,109,386	152,056
2024	442.6	2,063,331	150,945
2025	448.5	2,075,814	151,605
2026	449.7	2,085,018	152,180
2027	450.8	2,094,518	152,778
2028	451.9	2,103,554	153,338
2029	453.0	2,112,511	153,890
2030	454.0	2,122,155	154,497
2031	455.0	2,131,721	155,097
2032	456.0	2,140,816	155,659
2033	456.9	2,150,224	156,245
2034	457.9	2,159,963	156,857
2035	458.8	2,169,263	157,434
2036	459.7	2,178,527	158,007
2037	460.5	2,188,144	158,607
2038	461.4	2,197,711	159,203
2039	462.2	2,206,829	159,763
2040	463.0	2,215,912	160,321
2041	463.7	2,225,370	160,909
2042	464.5	2,234,422	161,466
2043	465.2	2,243,467	162,022
2044	465.9	2,252,894	162,610
2045	466.6	2,261,897	163,165
2046	467.3	2,270,482	163,687
2047	468.0	2,279,057	164,209
2048	468.6	2,287,636	164,732
2049	469.3	2,296,224	165,258
2050	469.9	2,304,816	165,785

*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 sales forecasts, using the economic estimator Gross Regional Product ("GRP").

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 sales forecasts. The specific steps used to develop the confidence interval are described in 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 and were downscaled based on the Company's share of statewide load in 2019. 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 growth rate is expected to be 2.1%. Total system load will reach 3,895 GWh by 2050, almost double of the current system load. Additional details for this forecast can be found in E3's Technical Report (Appendix F).

Table 4-4
Increased Electrification Forecast

Units: GWh	2022	2025	2030	2035	2040	2045	2050
Residential Space Heating	5.5	27.4	90.7	168.0	258.2	335.8	378.3
Commercial Space Heating	2.2	10.4	33.6	63.6	93.6	112.3	119.9
Residential Water Heating	1.1	6.4	29.7	59.7	81.6	95.3	104.3
Commercial Water Heating	0.4	2.1	7.2	14.9	22.5	27.9	31.3
LDV Charging	8.9	40.9	137.9	269.3	402.4	506.4	575.9
MHDV Charging	3.6	16.7	55.2	129.3	232.8	317.8	380.5
Total Building Electrification Load	9.2	46.2	161.2	306.2	455.9	571.2	633.8
Total Vehicle Electrification Load	12.5	57.6	193.0	398.6	635.1	824.2	956.4

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)			Energy (GWh)		
	Low	Base	High	Low	Base	High
2022	433.2	435.5	437.7	2,105	2,112	2,119
2023	437.3	441.7	446.2	2,096	2,109	2,122
2024	435.9	442.6	449.3	2,044	2,063	2,083
2025	439.7	448.5	457.5	2,049	2,076	2,102
2026	438.7	449.7	460.9	2,052	2,085	2,119
2027	437.7	450.8	464.2	2,054	2,095	2,136
2028	436.8	451.9	467.6	2,056	2,104	2,153
2029	435.7	453.0	470.9	2,058	2,113	2,169
2030	434.7	454.0	474.1	2,060	2,122	2,186
2031	433.7	455.0	477.4	2,062	2,132	2,204
2032	432.7	456.0	480.6	2,064	2,141	2,220
2033	431.7	456.9	483.8	2,067	2,150	2,238
2034	430.6	457.9	487.0	2,069	2,160	2,256
2035	429.6	458.8	490.1	2,071	2,169	2,273
2036	428.5	459.7	493.3	2,073	2,179	2,290
2037	427.5	460.5	496.4	2,076	2,188	2,308
2038	426.4	461.4	499.5	2,078	2,198	2,326
2039	425.3	462.2	502.5	2,080	2,207	2,343
2040	424.3	463.0	505.5	2,083	2,216	2,360
2041	423.2	463.7	508.6	2,085	2,225	2,378
2042	422.1	464.5	511.6	2,087	2,234	2,395
2043	421.0	465.2	514.5	2,090	2,243	2,412
2044	419.9	465.9	517.5	2,092	2,253	2,430
2045	418.8	466.6	520.5	2,094	2,262	2,447
2046	417.7	467.3	523.4	2,097	2,270	2,464
2047	416.6	468.0	526.3	2,099	2,279	2,480
2048	415.4	468.6	529.3	2,101	2,288	2,496
2049	414.3	469.3	532.2	2,104	2,296	2,513
2050	413.1	469.9	535.1	2,106	2,305	2,529

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
2022	433.2	435.5	437.7	332.1	332.8	333.5
2023	437.3	441.7	446.2	334.4	335.8	337.1
2024	435.9	442.6	449.3	331.5	333.5	335.5
2025	439.7	448.5	457.5	335.6	338.2	340.9
2026	438.7	449.7	460.9	334.9	338.2	341.5
2027	437.7	450.8	464.2	334.2	338.1	342.1
2028	436.8	451.9	467.6	333.5	338.0	342.7
2029	435.7	453.0	470.9	332.8	338.0	343.2
2030	434.7	454.0	474.1	332.1	337.9	343.8
2031	433.7	455.0	477.4	331.4	337.7	344.3
2032	432.7	456.0	480.6	330.6	337.6	344.8
2033	431.7	456.9	483.8	329.9	337.5	345.3
2034	430.6	457.9	487.0	329.2	337.4	345.8
2035	429.6	458.8	490.1	328.5	337.2	346.2
2036	428.5	459.7	493.3	327.8	337.1	346.7
2037	427.5	460.5	496.4	327.0	336.9	347.1
2038	426.4	461.4	499.5	326.3	336.7	347.5
2039	425.3	462.2	502.5	325.6	336.6	347.9
2040	424.3	463.0	505.5	324.9	336.4	348.4
2041	423.2	463.7	508.6	324.1	336.2	348.7
2042	422.1	464.5	511.6	323.4	336.0	349.1
2043	421.0	465.2	514.5	322.7	335.8	349.5
2044	419.9	465.9	517.5	321.9	335.6	349.8
2045	418.8	466.6	520.5	321.2	335.3	350.2
2046	417.7	467.3	523.4	320.4	335.1	350.5
2047	416.6	468.0	526.3	319.7	334.9	350.9
2048	415.4	468.6	529.3	318.9	334.6	351.2
2049	414.3	469.3	532.2	318.2	334.4	351.5
2050	413.1	469.9	535.1	317.4	334.2	351.9

4.7 Historical Peak Demand and Annual Energy and Comparison to the 2016 ERP

The Company has historically experienced its annual peaks in the summer. Peak demand and annual energy for the period 2017-2021 are provided on Table 4-7. Since 2017, the summer peak has experienced an average annual growth rate of 0.62 percent, the winter peak has experienced an average annual declining growth rate of -0.24 percent, and the historical annual energy experienced an average annual declining growth rate of -0.04 percent.

Table 4-7
Historical Peak Demand and Annual Energy

	Peak Demand				Annual Energy*		Summer Load Factor (%)	Winter Load Factor (%)
Year	Summer (MW)	Summer % Change	Winter (MW)	Winter % Change	GWh	% Change		
2017	398		299		2,055		58.95%	78.47%
2018	413	3.77%	291	-2.68%	2,125	3.37%	58.73%	83.35%
2019	422	2.18%	292	0.34%	2,104	-0.97%	56.92%	82.26%
2020	401	-4.98%	297	1.71%	2,052	-2.46%	58.42%	78.88%
2021	407	1.50%	296	-0.34%	2,051	-0.08%	57.52%	79.08%
Average Annual Growth (%)		0.62%		-0.24%		-0.04		

* Annual energy includes transmission and distribution losses.

A comparison of the peak demand and energy forecasts from the 2016 ERP and this 2022 ERP is shown in Table 4-8. In the 2016 ERP, the annual energy growth was projected at 0.82 percent over the 2016-2040 period, as compared to the 0.31 percent growth rate projection in the current plan over the 2022-2050 time period. The annual peak demand growth over the 2016-2040 period was forecasted at 0.44 percent in the 2016 ERP, compared to the peak demand 2022 ERP growth rate projected to be 0.27 percent, as shown in Table 4-8.

Table 4-8
Peak Demand and Energy Forecast Comparison

Year	Annual Energy (GWh)		Peak Demand DSM (MW)	
	2016 ERP	2022 ERP	2016 ERP	2022 ERP
2016	2,037		395	
2017	2,066		395	
2018	2,085		394	
2019	2,124		397	
2020	2,156		401	
2021	2,157		401	
2022	2,145	2,112	397	435
2023	2,152	2,109	398	442
2024	2,174	2,063	401	443
2025	2,195	2,076	404	449
2026	2,216	2,085	406	450
2027	2,237	2,095	409	451
2028	2,259	2,104	411	452
2029	2,280	2,113	414	453
2030	2,301	2,122	416	454
2031	2,320	2,132	419	455
2032	2,338	2,141	421	456
2033	2,356	2,150	423	457
2034	2,375	2,160	426	458
2035	2,393	2,169	428	459
2036	2,411	2,179	430	460
2037	2,428	2,188	432	461
2038	2,444	2,198	435	461
2039	2,460	2,207	437	462
2040	2,477	2,216	439	463
2041		2,225		464
2042		2,234		464
2043		2,243		465
2044		2,253		466
2045		2,262		467
2046		2,270		467
2047		2,279		468
2048		2,288		469
2049		2,296		469
2050		2,305		470
2016 - 2040	**0.82%**		**0.44%**	
2022 – 2050		**0.31%**		**0.27%**

4.8 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.

4.9 Load Profiles

Typical day load patterns for Colorado Electric's system load presented for peak day, average day, and representative average off-peak days for each calendar month are provided in Appendix D. These monthly load shapes were developed from hourly system demand data for the year 2020 and reflect average customer use for the system.

5.0 Supply-Side Resources

5.1 Existing Owned Resources

The Company's owned generation resources consist of three existing natural gas combustion turbines, three 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 Pueblo diesels, 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 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 dispatchable resources and then discusses the dispatchable resources procured through PPA's in subsection 5.2. Section 5.3 addresses the renewable resources either owned by the Company or procured through PPAs, as well as its other renewable resources provided by distributed resources and community solar gardens.

Table 5-1
Existing Owned Generating Facilities

Unit Name	Year Installed	Nameplate Capacity (MW)	Summer Capacity (MW)	Forced Outage Rate (%)	Scheduled Outage Rate (%)	Fuel Type	Fully Loaded Heat Rate (Btu/kWh)	Probable Retirement Date
PAGS LMS100 1	2012	90	90	2.0	2.2	Nat Gas	8,868	2047
PAGS LMS100 2	2012	90	90	2.0	2.2	Nat Gas	8,868	2047
PAGS LM6000	2017	40	40	2.0	1.1	Nat Gas	9,201	2051
Pueblo Diesels[1]	1963	8.0	8	2.0	0.5	#2 Oil	10,425	2029
Airport Diesels[1]	1964	10.0	10	2.0	0.5	#2 Oil	10,425	2033
Rocky Ford Diesels[1]	1964	10.0	10	2.0	0.5	#2 Oil	10,425	2029
Busch Ranch I Wind Project	2012	14.5	2.0	0.0	0.0	Wind	N/A	2037
Peak View Wind Project	2016	60	8.4	0.0	0.0	Wind	N/A	2041
Total Capacity			**258.4**					
Notes: 1. There are five 2 MW diesel units at Rocky Ford. There are four 2 MW diesel units at Pueblo. There are four 2.5 MW diesel units at the Airport. Early retirement of Pueblo and Airport Diesels in 2025 was considered.								

5.1.1 Diesels

The diesel units commonly known as the Pueblo, 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 MW diesel units at Pueblo. There are four 2.5 MW diesel units at the Airport location.

5.1.1.1 Retirements

The Company is proposing to retire the Pueblo and Airport Diesel units early, 2025 instead of 2029 and 2033, respectively. Early retirement of the Pueblo and Airport Diesels in 2025 is considered in all scenarios except the Base ERP scenario to further comply with the CEP requirements. The Rocky Ford Diesels will be needed to provided voltage support to the Company's transmission system transitionally as CEP resources are brought online. The Company will, however, achieve emissions reductions necessary to achieve the State's 80 by 30 emissions reductions targets, and it will therefore retire them at the end of 2029 rather than consider extending the Rocky Ford units. For these reasons, the costs associated with retiring all three diesel plants are CEP costs eligible for recovery through the CEPR.

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 an indicative estimate from an experienced decommissioning consultant, the Company projects the additional cost of decommissioning the Pueblo and Airport Diesels will be approximately $540,000 and $549,000, respectively, and the additional decommissioning cost for the Rocky Ford Diesel units will be approximately $616,000. The Company plans to issue an RFP for the decommissioning work and track the actual cost of decommissioning the units in a regulatory asset for recovery through the CEPR. For the Pueblo and Airport Diesel units, these units are almost fully depreciated but have approximately $1.9 million book value remaining. Black Hills is proposing to accelerate the remaining depreciation schedule on each unit by four years (Pueblo Diesel) and eight years (Airport Diesel), to be recovered through the CEPR.

5.1.2 Pueblo Airport Generating Station ("PAGS")

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 Purchases

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 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.

Firm power is also purchased through what is referred to as the "MPS Agreement". This agreement expires on September 30, 2024 and provides 5 MW of firm capacity and energy to the Company. The first year modeled in RESOLVE is 2025 and therefore, MPS Agreement is not included in this analysis.

For the modeling completed for this Plan, the Company assumed that all of the existing purchases 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)	Summer Capacity (MW)	Fuel Type	Fully Loaded Heat Rate (Btu/kWh)	Probable Retirement Date
PAGS IPP Combined Cycles	2012	200	200	Natural Gas	7,450	2031
MPS Agreement	1997	5	5	PPA	N/A	2024
Busch Ranch I Wind Project	2012	14.5	2.0	Wind	N/A	2037
Busch Ranch II Wind Project	2019	60	2.0	Wind	N/A	2044
Total Capacity			**209.0**			

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 Renewables

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

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 the RES Rules.

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 Solar 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 <u>on-site</u> and have it interconnected with the Company's grid for parallel operation. These are generally known as behind-the-meter ("BTM") resources. The participating customers received either standard rebate offers or production-based incentives. In return, the Company received the RECs generated by these systems. The RECs are counted toward the Company's compliance with the state's Renewable Energy Standard ("RES"). The size of the PV solar system was limited by statute to 120% of the customer's average annual consumption at the site.

Concurrently with this filing, the Company is also filing for Commission approval of its 2023-2026 RES Compliance Plan. For the 2023-2026 RES Compliance Plan, the Company is modifying these incentive programs to comply with recently enacted legislation, SB21-261 and to adopt to the changing customer needs. Of note, the Company is increasing its emphasis on its income qualified ("IQ") programs.

In addition to the Company-sponsored programs, 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 solar resources. These totals were aggregated to include existing and forecasted resources and are reflected in Table 5-3 below.

Table 5-3
Distributed Solar Parameters

	2025	2030	2035	2040	2045	2050
BTM Solar	51.6	48.1	44.2	40.1	35.7	31.2

5.3.4 Community Solar Gardens

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.

For the 2023-2026 RES Plan compliance period, the Company is proposing to acquire a maximum of 4 MW per year. This compares with a maximum 2.5 MW per year in previous RES Plan compliance periods. For ERP modeling purposes, the Company modeled CSG capacity up to 5 MW per year.

The Company's proposed CSG acquisition will be under two methods: (1) an IQ Standard Offer, and (2) a competitive solicitation ("Open RFP"). Under the IQ Standard Offer, CSG capacity will be available on a first come, first served basis. The

IQ Standard Offer is designed to further expand access to CSG capacity for IQ customers in the Company's service territory.

The 2023-2026 RES Compliance Plan provides further details about the Company's proposed CSG acquisition program.

For purposes of the modeling, totals were assumed to encompass all CSG resources. These totals were aggregated to include existing and forecasted resources and are reflected in Table 5-4 below.

Table 5-4
Community Solar Garden Parameters

	2025	2030	2035	2040	2045	2050
Community Solar Garden	18.9	31.4	31.3	31.2	30.9	30.2

5.3.5 Turkey Creek Solar Project

The Turkey Creek Solar Project, located west of the City of Pueblo in Pueblo County, Colorado, was targeted to come online in December 2024. Upon commercial operation of the facility, the Company would purchase the energy produced by the 200 MW photovoltaic panels under a PPA that had a 15-year term from the date of commercial operation of the facility. The Company was working through modifications to the PPA Agreement through good faith negotiations with the developer. In the scenarios that include Turkey Creek, the Company had updated to the new proposed price at the time of the negotiations. The one-year commercial operation date delay had no impact to the modeling, since capacity expansion is completed in five one-year increments beginning in 2025. Citing broader issues in the market for solar photovoltaic materials, TC Colorado was unable to provide assurances it would be able to deliver the project at a price that would be beneficial to customers on the timeline Black Hills required for its prudent planning purposes. Thus, the scenarios with Turkey Creek presented in this Plan are for informational purposes only. The Company's Preferred Plan does not include the Turkey Creek Project.

5.3.6 Commercial/Industrial Solar Generation

The Company's commercial and industrial customers have expressed an interest in additional on-site solar solutions. For this Plan, the Company included a scenario in which an 80 MW solar project was added in 20 MW increments in years 2025, 2026, 2027, and 2028. This resource was only modeled in the Commercial and Industrial ("C&I") Generation CEP scenarios. The pricing was provided by E3 and reflects the same pricing as the utility scale candidate solar resources. As discussed in the RES Plan, the Company is not proposing a specific commercial/industrial solar program at this time. However, the Company will continue to work with its customers to find an appropriate solution to meet their needs and could in the future propose a new program. For this Plan, the Company included a scenario with additional amounts of solar generation to obtain an understanding of the impact it would have on emissions reductions.

5.3.7 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. That agreement expires in June 2030.

5.4 Candidate Resources Options

Conventional resources, renewable energy resources, and purchased power 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 Company engaged E3 to provide solar, wind, and battery resource options. Costs of new wind and solar are based on NREL's 2020 Annual Technology Baseline ("ATB") Report, as seen in Appendix G. Costs for battery storage were developed by E3 and are generally consistent with Lazard's Levelized Cost of Storage 6.0,[24] and future cost projections were based on long-term cost trajectories published in NREL's ATB.

The Plan modeled both fuel-fired and renewable resources and analyzed several resource characteristics such as capacity, capital cost, operating cost, and outage rates.[25] Detailed descriptions of these candidate resource options follow.

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[24] Report available at: https://www.lazard.com/media/451418/lazards-levelized-cost-of-storage-version-60.pdf.

[25] 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 Appendix F: E3 Technical Report conducted by E3.

5.4.1 Conventional

Conventional supply-side resource options were available for selection in the modeling. The natural gas-fired resources were assumed to be built in the Pueblo area at a “greenfield” or undeveloped 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 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.

Performance parameter and cost values for modeling conventional resources came from a 2021 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 with Hydrogen Co-firing

Combustion turbines (“CT”) typically burn natural gas and/or hydrogen blend 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 baseload capacity. Many CTs have the added benefit of providing quick-start and black-start capability in certain configurations. In this analysis, technology options modeled for CTs included LMS 100 with 30% H_2 Co-firing (an aeroderivative turbine), LM6000 PC with 35% H_2 Co-firing, and a LMS2500 +G4 with 75% H_2 Co-firing. These units were assumed to operate on natural gas until 2050 when they operate on hydrogen fuel. Modeled CTs assume ownership at a greenfield site. Parameters used to model each of these CT options are shown on Table 5-5.

Table 5-5
Combustion Turbine Parameters

Parameter	LMS 100	LM6000	LMS2500
Earliest feasible installation	1/2025	1/2025	1/2025
Size, MW (net) - summer	97	43	30
Full load heat rate, Btu/kWh	8,850	9,890	10,810
SO_2 Emission Rate, lb/MWh	0.0004	0.0004	0.0002
NO_x Emission Rate, lb/MWh	0.16	0.18	0.19
CO_2 Emission Rate, lb/MWh	890	970	630
Fixed O&M, $/kW-year (2021 $)	18.00	43.00	51.00
Variable O&M, $/MWh (2021 $)	5.30	7.80	10.20
Forced Outage Rate, %	2.5	2.5	1.3
Maintenance Outage Rate, %	1.7	1.7	2.7
Capital Cost, $/kW (2021 $)	1,027	1,249	1,354

5.4.1.2 Geothermal

Geothermal is a carbon-free firm resource. Geothermal energy is generated from heat that exists below the surface of the earth. This heat produces hot water or steam that is extracted from the earth and used to spin a turbine which in turn powers a generator for electric production. There are three conventional types of geothermal technologies used to generate electricity: dry steam, flash steam and binary cycle. The type of technology used depends on the state of the water or steam, as well as its temperature. In a dry steam plant, fluid from the earth travels directly to the turbine, while a flash steam plant pumps the fluid under high pressure to a tank at the surface held at a lower pressure, thus causing the fluid to flash to a vapor (e.g., steam). This vapor is then directed to the turbine. In a binary cycle plant, fluid from the earth passes through a heat exchanger at the earth's surface where the secondary fluid is flashed to vapor and directed to the turbine. Modeled Geothermal assumes ownership at a greenfield site. Parameters used to model geothermal are shown on Table 5-6.

Table 5-6 Geothermal Parameters

Parameter	Geothermal
Earliest feasible installation	1/2025
Size, MW (net) - summer	40
Full load heat rate, Btu/kWh	N/A
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 (2021 $)	200.00
Variable O&M, $/MWh (2021 $)	N/A
Forced Outage Rate, %	5.1
Maintenance Outage Rate, %	7.3
Capital Cost, $/kW (2021 $)	7,146

5.4.1.3 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 small modular reactor are shown on Table 5-7.

Table 5-7 Small Modular Reactor Parameters

Parameter	SMR
Earliest feasible installation	1/2030
Size, MW (net) - summer	100
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 (2021 $)	100.00
Variable O&M, $/MWh (2021 $)	3.00
Forced Outage Rate, %	0.7
Maintenance Outage Rate, %	4.3
Capital Cost, $/kW (2021 $)	3,782

5.4.2 Seasonal Firm Market Purchased Power

The Company assumed that, due to its small size relative to the market, it will be able to purchase seasonal firm market power. This measure covers any peak demand shortfall and defers the need to install new resources until the need for capacity extends to multiple months. The product would be seasonal firm market power available 6 x 16 (six days per week, sixteen hours per day, 7 am – 11 pm). The model can select the seasonal firm market power in 10 MW blocks, up to a total of 50 MW (five blocks). This seasonal firm market power is priced at the cost of energy at Palo Verde plus a 20 percent premium and transmission adder. The 10-MW block size was selected based on the minimum size of the blocks of power typically available for this type of product in the market.

5.4.3 Renewable Energy Resources

The renewable energy resource technologies that were modeled in this Plan include PV solar, wind, and storage. Data for performance and cost parameters for solar, wind, and storage technology were provided by E3.

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 provides additional details regarding integration costs and accredited capacity.

5.4.3.1 Photovoltaic Solar

Solar photovoltaic (PV) 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 over single-axis panels, however they are more expensive to build and install and require more land, and thus are not as cost-effective.

The Company included PV solar facilities for selection in the modeling from different energy resource zones (ERZs[26]). There are no limitations included in the model on 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 5-8. Parameters can vary for each ERZ and are discussed in detail in E3's Technical Report, Appendix F. Recent legislation related to ITC levels for 2022 through 2050 were included in the development of the PV solar cost assumptions.

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

Table 5-8
PV Solar Performance Parameters

Parameter	PV Solar
Earliest feasible year of installation	1/2025
Size, MW (net) - summer	unlimited
Capacity Factor, %	29-32
Forced Outage Rate, %	0.00
Maintenance Outage Rate, %	0.00
Fixed O&M*, $/kW-year (2021 $)	6.57-11.21
Capital Cost, $/kW (2021 $)	671-1,071
Levelized Cost of Energy, $/MWh (2021 $)	15.88-22.49

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

5.4.3.2 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. Recent legislation related to PTC levels for 2022 through 2025 were included in the development of the wind resource cost assumptions. Parameters used to model wind in this 2022 Plan, which assume a PPA for wind, are shown in Table 5-9. Parameters can vary for each ERZ and are discussed in detail in E3's Technical Report, Appendix F.

Table 5-9
Wind Performance Parameters

Parameter	Wind
Earliest feasible year of installation	1/2025
Size, MW (net) - summer	unlimited
Forced Outage Rate, %	0.00
Maintenance Outage Rate, %	0.00
Capacity Factor, %	45-48
Fixed O&M*, $/kW-year (2021 $)	35.43-43.58
Capital Cost, $/kW (2021 $)	1,075-2,386
Levelized Cost of Energy, $/MWh (2021 $)	25.59-39.75

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

5.4.4 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.

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. Parameters used to model storage in this 2022 Plan, which assume a PPA for storage, are shown in Table 5-10.

Table 5-10
Storage Performance Parameters

Parameter	Storage
Size, MW (net) – summer and winter	unlimited
Efficiency (%)	85
Duration (hours)	4
Fixed O&M, $/kW-year (2021 $)	8.31
Capital Cost, $/kW (2021 $)	458-802
Total Levelized Fixed Costs $/kW-yr (2021 $)	60.80-98.46

5.4.5 Commercial/Industrial Solar Generation

As discussed above, the Company included a scenario in which an 80 MW solar project was added in 20 MW increments in years 2025, 2026, 2027, and 2028. This resource was only modeled in the C&I Generation CEP scenarios. The pricing was provided by E3 and reflects the same pricing as the utility scale candidate solar resources. A summary of the performance parameters are provided below in Table 5-11.

Table 5-11
Industrial Generation Performance Parameters

Parameter	Industrial Solar
Earliest feasible year of installation	1/2025
Forced Outage Rate, %	0.00
Maintenance Outage Rate, %	0.00
Capacity Factor, %	25.2
Fixed O&M*, $/kW-year (2021 $)	6.57-11.21
Capital Cost, $/kW (2021 $)	671-1,071

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

6.0 Costs and Benefits of Integration for Intermittent Renewable Energy Resources

To comply with SB19-236'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 assure that grid stability is not compromised. Black Hills purchases ancillary services and incurs integration charges from PSCo. In 2021, 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 wind and solar resources for reliability planning purposes; and second to determine the reliability target through a Planning Reserve Margin Study to maintain system reliability. The studies are contained in E3's Technical Report, Appendix F.

6.1 Wind and Solar Integration Costs

Black Hills incurs integration charges for all renewables on its system, including existing owned and contracted renewables, since Black Hills must purchase ancillary services from PSCo. The integration charges are calculated based on PSCo's Schedule 3 and 16 tariffs.[27] Schedule 3 costs include Ancillary Service Charges and Variable Energy Resources ("VER") Generation and Frequency Response charges. Schedule 16 costs include Ancillary Service Charges and Flex Reserve Service. The charges for each tariff are projected to remain constant in real dollars over the modeling horizon. Charges for each resource type are detailed in Table 6-1.

Table 6-1
Wind and Solar Integration Costs

Parameter	Schedule 3 (2021$/kW-mo)	Schedule 16 (2021$/kW-yr)	Total Integration Cost (2021$/kW-mo)	Total Integration Cost (2021$/kW-yr)
Wind	$0.1434	$0.6914	$0.8348	$10.0173
Solar	$0.1434	$0.0000	$0.1434	$1.72050

6.2 Resource Adequacy

E3 calculated the accreditable capacity of future levels of wind, solar, and storage resources utilizing an Effective Load Carrying Capability ("ELCC") analysis to determine the percentage of the nameplate capacity that can be counted on for

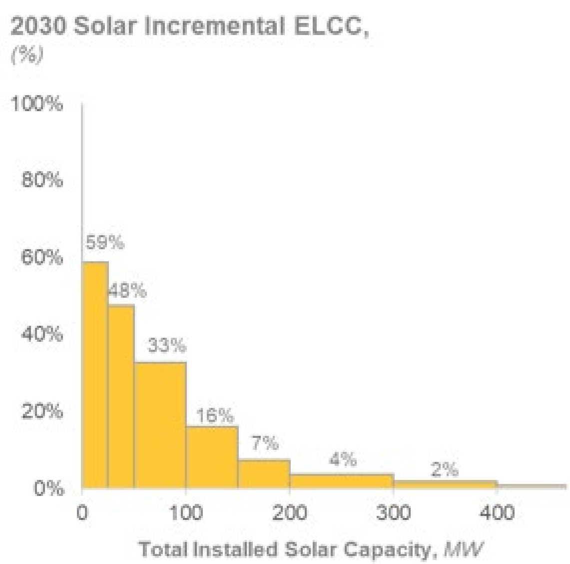
[27] See tariff rates in Section 2.a.(i) - PSCo Transmission Formula 2020 Estimate

reserve margin planning purposes. Additionally, E3 calculated the planning reserve margin target utilizing a Loss of Load Probability ("LOLP") analysis to determine the amount of capacity needed above expected peak demands to maintain reliability. Both types of resource adequacy studies included the assumption that Black Hills was "islanded." This means that there was not an ability to procure economy energy from neighboring utilities on short notice, but there was an ability to count SFMP as a firm resource. The islanded assumption allows the Company to maintain its reliability with the use of its own resources, regardless of market availability.

6.3 Accreditable Capacity of Wind, Solar and Storage

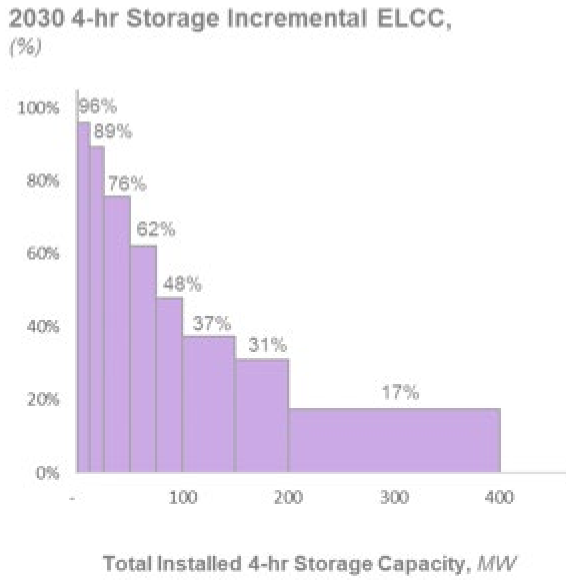
E3 calculated the accreditable capacity of future levels of wind, solar, storage and solar plus storage resources utilizing an Effective Load Carrying Capability ("ELCC") analysis to determine the percentage of the nameplate capacity that can be counted on for reserve margin planning purposes. For this analysis E3 used the ELCC methodology that determines the quantity of "perfect" capacity that could be replaced or avoided by a non-firm resource while providing equivalent system reliability. ELCC is calculated based on a Loss of Load Expectation ("LOLE") metric (e.g., 0.1 days/year). LOLE is the amount of time during which system capacity is unable to meet system load. The calculated ELCC at different solar, storage, and wind penetrations on the Black Hills system can be seen in Figures 6-1, 6-2, and 6-3, respectively.

Figure 6-1
Calculated Solar ELCC



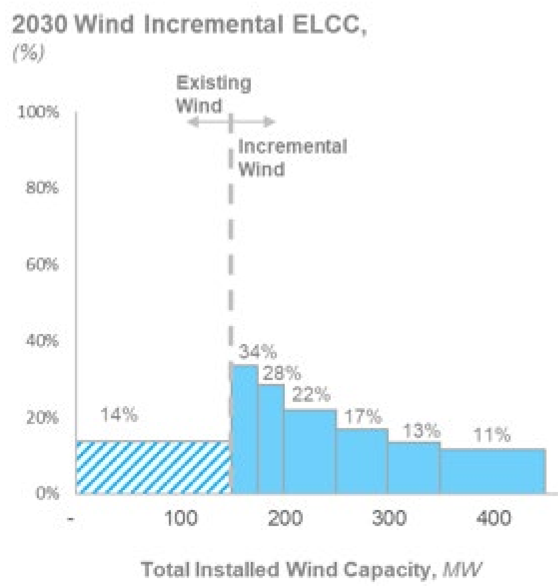
Source: E3, Appendix F

Figure 6-2
Calculated Storage ELCC



Source: E3, Appendix F

Figure 6-3
Calculated Wind ELCC



Source: E3, Appendix F

The existing solar ELCCs are higher than those for wind since their load profiles provide peak output closer to times when Black Hills most needs the power. As more and more 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, Appendix F, provides additional details around this analysis. Tables 6-2 and 6-3 show the ELCC for incremental wind, solar, storage, and solar plus storage additions to the Black Hills system.

Table 6-2
Incremental Wind ELCC

Total Wind Nameplate (MW)	Effective Capacity Value (Effective MW)	Incremental ELCC (%)
150	20	14
175	29	34
200	36	28
250	47	22
300	55	17
350	62	13
450	73	11
550	83	9
750	96	7
950	106	5

Source: E3, Appendix F

Table 6-3
Calculated Solar and Storage ELCC

Solar and Storage Effective Capacity Value Matrix (Effective MW)	Storage Nameplate Capacity (MW)								
Solar Nameplate Capacity (MW)	0	12.5	25	50	75	100	150	200	400
0	0	12	23	42	58	70	88	104	139
25	15	26	38	57	72	83	101	115	148
50	27	38	50	69	84	95	112	126	158
100	43	55	67	86	101	113	130	144	176
150	51	63	75	97	114	126	145	158	191
200	55	67	79	102	121	135	156	169	202
300	58	71	82	105	126	143	166	181	219
400	60	72	84	107	128	145	169	186	230

Source: E3, Appendix F

6.4 Planning Reserve Margin

E3 calculated the planning reserve margin target required to meet Black Hills' system reliability criterion. E3 utilized an LOLP analysis to determine the amount of capacity needed above expected peak demands to maintain reliability. LOLP is made up of several components: The 1-day-in-10-year reliability target was used as the Loss of Load Expectation analysis, Loss of Load Hours ("LOLH") provides the expected hours with a loss of load event, Expected Unserved Energy ("EUE") provides the quantity of energy that is unserved due to loss of load, and the Annual Loss of Load Probability ("aLOLP") to determine the probability of at least one loss of load event occurring. E3's analysis determined a 24% PRM requirement is needed to achieve the LOLE of 0.1 days per year. This requirement represents the amount of capacity needed above the forecasted median peak to ensure an adequate level of reliability while allowing for the impacts of extreme weather on electric demands, the possibility of unit forced outages (which can be especially impactful on a system with the Company's relatively small size), and the need to maintain a minimum level of operating reserves. Additional details can be found in E3's Technical Report, Appendix F.

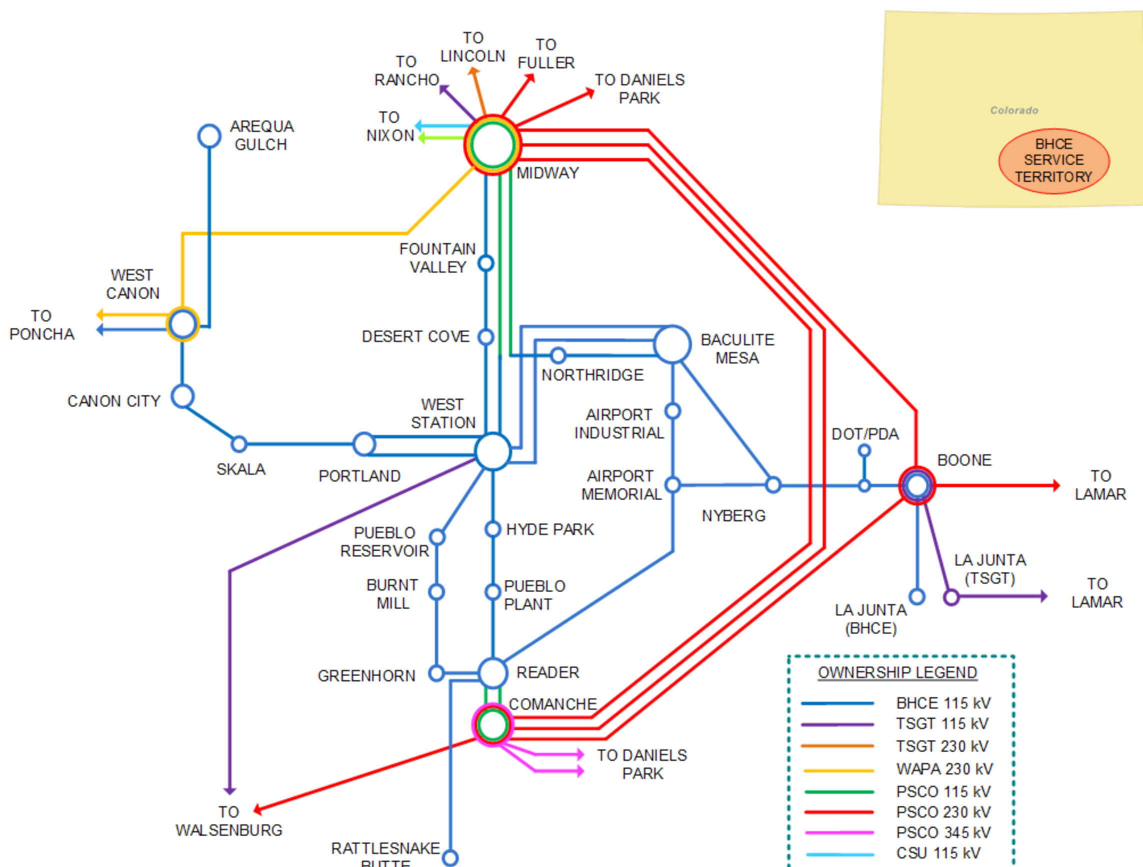
7.0 Transmission System

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 350 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 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 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 ("WECC,"), 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 2022, WestConnect had 25 members, including 18 Transmission Owners, five Independent Transmission Developers, and two Key Interest Group members. 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 80 x 30 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.

The transmission system is currently constrained when transferring power from the Pueblo area into the Cañon City load center, or through the system from Portland to West Cañon. The West Station-West Cañon 115 kV project was constructed to address this constraint. Siting future generation on the 115 kV or 69 kV system between Portland and Cañon City may help to further alleviate this constraint.

There is also a general constraint on the Black Hills transmission system when moving power from Baculite Mesa toward Midway under contingency conditions. There are limited paths for energy to flow out of Baculite Mesa, and following the loss of the Baculite Mesa-West Station 115 kV double circuit, the remaining outlet paths become constrained. Future generation additions at Baculite Mesa may require transmission upgrades to maintain unrestricted transfers under contingency conditions. This constraint is dependent on surrounding system conditions as well as the nature of the generation dispatched at Baculite Mesa.

Another constraint on the Black Hills transmission system can exist when transferring power to the La Junta/Rocky Ford area under contingency conditions. The loss of the single 115 kV line feeding the area via the Boone substation requires the area load to be served from the single 69 kV line also terminating at Boone. By adding generation in the La Junta/Rocky Ford area, the likelihood of realizing a transmission constraint following a transmission outage is reduced.

As part of Black Hills' Phase II bide valuation 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 2022 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 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

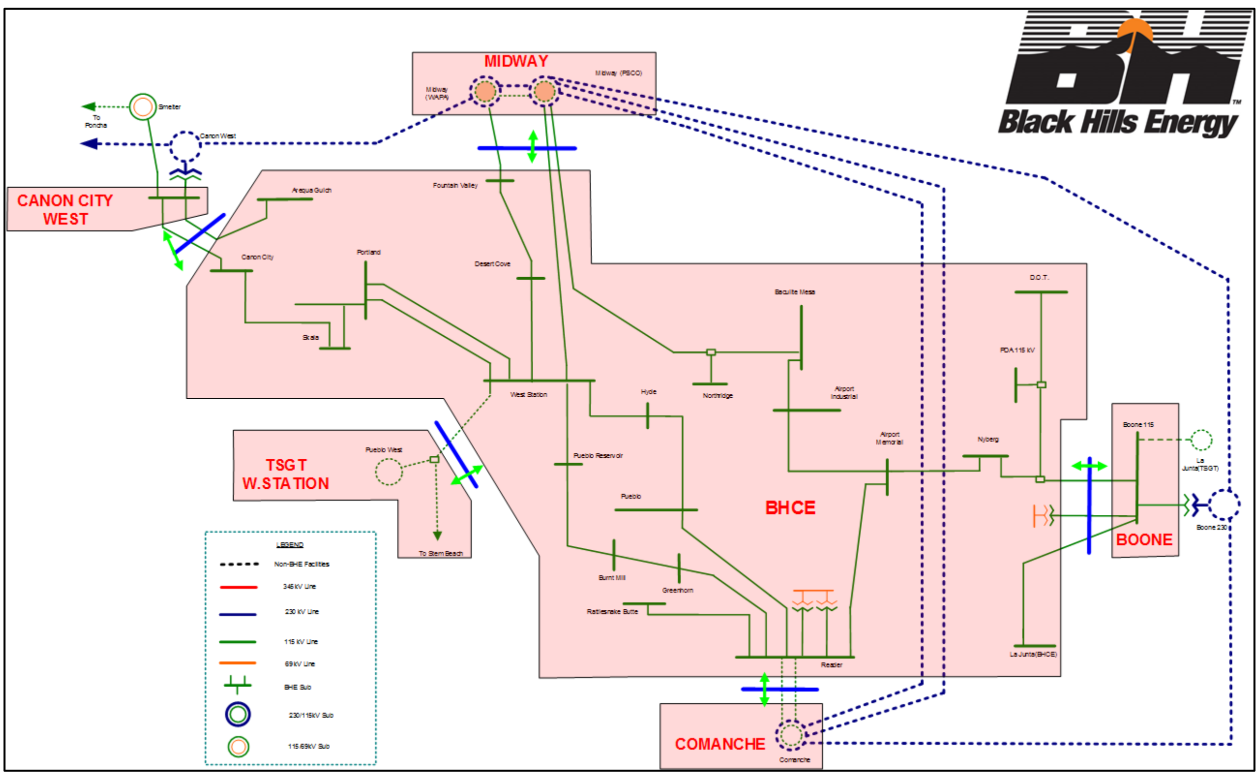


Table 7-1

Transfer Path Capability

	Utility	Total Transfer Capability (MW)*	Available Transfer Capability (MW)*
Midway-Black Hills	PSCo, TSGT & WAPA	320	192
Black Hills-Midway	PSCo, TSGT & WAPA	320	320
Black Hills-West Station	TSGT	145	87
Black Hills-Reader	PSCo	730	730
Reader-Black Hills	PSCo	730	730
Black Hills-Cañon City West	PSCo & WAPA	120	120
Cañon City West-Black Hills	PSCo & WAPA	100	100
Black Hills-Boone	PSCo & TSGT	198	198
Boone-Black Hills	PSCo & TSGT	198	186

7.4 Transmission Projects

Black Hills' load growth has increased over the past couple of years, driven primarily by large industrial load expansions as well as some commercial load growth. The Black Hills projects included in the 2022 Rule 3627 Filing (Proceeding No. 22M-0016E) and 2022 Rule 3206 filing (Proceeding No. 22M-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 2022 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 2020 10-Year Plan, Black Hills has completed three projects: Desert Cove-Midway 115 kV line rebuild, Airport Memorial – Nyberg 115 kV line rebuild, and Boone – La Junta 115 kV line rebuild. Black Hills identified eight planned projects within the upcoming 10-year planning horizon that represent $76.9 million in capital expenditures between 2020 and 2023. The projects were identified to increase reliability within Black Hills' network transmission system, to support voltage, 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. The projects in this section were coordinated with stakeholders and neighboring entities to ensure the best solution is achieved while avoiding duplication of facilities.

Transmission system upgrades related to renewable generation interconnections are discussed below. Planned 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' 2022 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

Three projects, shown in Table 7-2, address reliability and integrity concerns in the Cañon City area. Local load growth has driven the need for additional capacity in the area, as well as local voltage support. A new transmission line into the area and a substation rebuild will improve load service and operational flexibility.

Table 7-2
Cañon City Area Projects Included in the Black Hills 2022 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
West Station – Hogback Transmission Line[28]	1/2023	$24.0	Not required. Decision No. C17-0539
115/69 kV Hogback Ranch Substation Build	11/2022	$7.2	Not required. Decision No. C17-0539
115kV North Penrose Distribution Substation	12/2022	$6.7	Not required. Decision No. C20-0477

[28] This line also is known as the Southern Colorado Reliability Upgrade Project.

Black Hills' planning process identified these projects as solutions for expected concerns regarding reliability and anticipated load growth in the Cañon City area. The primary driver of the West Station – Hogback Transmission Line was to increase the reliability of Black Hills' transmission system feeding Cañon City and the surrounding area. Load growth in the Cañon City area has led to reliability concerns following the loss of the two transmission lines connecting that area to the Pueblo part of the Black Hills system. To mitigate these concerns, several options were considered. The West Station – Hogback 115 kV Transmission Line build is set to address the increased load growth in the area. The new connection also enables the future replacement of stressed transmission lines at a greatly reduced operational risk.

The Hogback Ranch project provides the added benefit of adding a 115/69 kV source near the existing North Cañon 69 kV substation. This will offload the existing Cañon City transformer and add operational flexibility to the local 69 kV system. The new source may provide future improved backup service to the Cripple Creek area via the normal open 69 kV line for emergency situations. The initial scope of the West Station - West Cañon project was coordinated with other entities to explore opportunities for joint participation in the project. This was done to potentially meet a wider range of system needs while minimizing the impact to the local landscape through the potential use of double circuit towers and utilization of existing transmission corridors when possible. The project was identified as a Senate Bill ("SB") 07-100 project in the 2015 SB 07-100 study because it facilitates a larger resource injection from Energy Resource Zone ("ERZ") 4. Refer to the Black Hills Corporation 2021 SB 07-100 Study Report included in Appendix N of the 2022 3627 Filing (Proceeding No. 22M-0016E) for more information.

The North Penrose Distribution Substation consists of constructing a new substation to accommodate two 115/13.2kV, 25MVA transformers. Currently, the community of Penrose is served radially on a 69kV line with limited contingency backup alternatives. This addition will provide the community with another source, while also offloading the 115/69kV transformers at Portland.

7.4.2 Pueblo Area

Three projects, shown in Table 7-3, address reliability and contingency concerns in the Pueblo area. There has been unanticipated significant growth in the Pueblo area that will be accommodated through these future projects.

Table 7-3
Pueblo Area Projects Included in the Black Hills 2022 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
115 kV Rodrigues Substation	6/2026	$7.0	Not required - Decision No. C19-638
115kV Pueblo West Distribution Substation	7/2023	$5.4	Not required - Decision No. C20-0477
115kV West Station-Greenhorn Line Rebuild	5/2022	$5.0	Not required - Decision C18-843

The 115 kV Rodrigues Substation project was determined by the planning team to address growth concerns for the increasing demand in Colorado and in this particular location. The Rodrigues Substation will relieve some of the load from existing distributions systems, while also supplying contingency and maintenance switching options. The addition of this substation also allows for increased capacity and contingency with distribution systems within the same area. The project still is in land negotiation phases; therefore, the total project cost will be updated when land acquisition costs are finally determined.

The 115kV Pueblo West Distribution Substation will be built to ultimately accommodate two 115/13.2kV, 25MVA transformers. This project is required to serve new industrial and agricultural load as well as contingency back-up for existing distribution infrastructure. This substation additionally addresses low voltage concerns under peak demand conditions for the area.

The 115kV West Station – Greenhorn Line rebuild is needed to address the age of the infrastructure. The existing 336 ACSR conductor will be replaced to increase the capacity of the line. This project will be a 12.1-mile-long rebuild that uses the current right-of-way. The project, once completed, will increase the line ratings to accommodate during summer and winter ratings.

7.4.3 Rocky Ford Area

Two projects, as shown in Table 7-4, address reliability and contingency concerns in the Rocky Ford area.

Table 7-4
Rocky Ford Area Projects included in the Black Hills 2022 10-Year Plan

Project Name	In-Service Date	Cost (millions)	CPCN
South Fowler Substation	4/20/2022	$5.10	Not required; Decision No. C19-0638
Boone – South Fowler 69/115kV Conversion	4/20/2022	$12.8	Not required; Decision No. C19-0638

Previously known as "La Junta Area Upgrades", the South Fowler Substation and Boone-South Fowler 69/115kV conversion replace this project. Black Hills performed a study designed to determine the integrity of the 69kV infrastructure. A thorough analysis concluded that a significant number of lines needed to be rebuilt to address issues associated with aging infrastructure within the near-term planning horizon. The addition of the South Fowler substation will be beneficial for offering additional capacity to the area, along with operational flexibility when rebuilding neighboring aged 69kV lines. The South Fowler substation will facilitate a La Junta substation outage at a later date to upgrade the existing La Junta transformer with a larger transformer. The Boone-South Fowler 69/115kV conversion will be accomplished using 795 ACSR conductor on double circuit structures to accommodate the new line, while maintaining a connection from Boone to Huerfano. This line will be a 19-mile build and will provide a second, geographically diverse 115/69 kV delivery point to the area.

Information concerning the specific Colorado projects included in the Black Hills 2022 10-Year Plan is contained in the Rule 3627 Filing in Proceeding No. 22M-0016E, also provided as Attachment SDN-2 to Mr. Seth D. Nelson's Direct Testimony supporting this Plan.[29] Black Hills' most recent Rule 3206 Report is provided as Attachment SDN-2 to Mr. Seth D. Nelson's Direct Testimony supporting this Plan.

[29] Additionally, general information is available at: https://www.blackhillsenergy.com/transmission-rates-and-planning/transmission-projects.

Table 7-5
Black Hills 2022 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
Boone-South Fowler 69 kV to 115 kV Conversion	19 miles; Pueblo & Otero County, CO	Apr. 2022	$13.0M	Boone, South Fowler	115 kV; 221 MVA	C19-0638	Rebuild the existing 69 kV line from Boone to S. Fowler Tap west of Rocky Ford, CO.
South Fowler Substation	Otero County, CO	Apr 2022	$5.0M	New South Fowler Substation	115 & 69 kV; 80 MVA	C19-0638	Increase load serving capability and reliability in the La Junta and Rocky Ford areas of BHCE's service territory.
West Station-Hogback 115 kV Transmission Project	35 miles; Fremont & Pueblo County, CO	Q1 2023	$24M	West Station 115 kV, New Hogback 115/69 kV Intermediate connections at new Pueblo West sub and new N. Penrose	115 kV; 221 MVA	C17-0539	new 115 kV line from West Station to a new load service substation in Cañon City (Hogback).
Hogback 115/69 kV Substation	Fremont County, CO	Nov 2022	$7.2M	New Hogback Substation	115 kV, 80 MVA	C17-0539	New 115/69 kV substation west of Cañon City on the West Station – Hogback 115 kV line. Formerly known as "Cañon City Area 115 kV/69 kV Substation" in 2018 Rule 3206 Report.

Table 7-5 cont.:

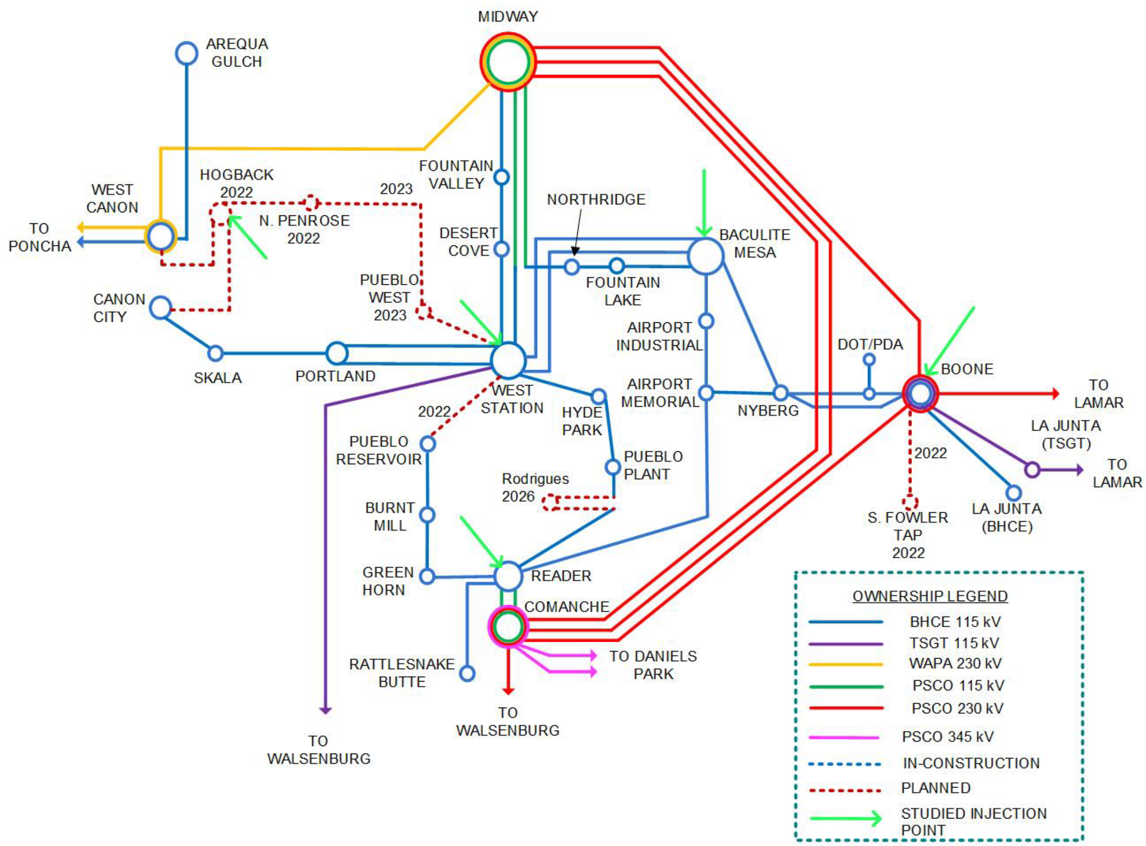
Black Hills 2022 Rule 3206 Planned Transmission Projects

Project	Length and Location	In-service Date	Estimated cost (millions)	Terminal Points	Voltage and MW Rating	Commission Decision/ Proceeding	Description
Desert Cove-Midway	14.8 miles, Pueblo & El Paso County, CO	Jan. 22, 2021	$6.4M	Desert Cove 115 kV, Fountain Valley 115 kV	115 kV; 171 MVAR	C18-0843	Rebuild the 115 kV line from Desert Cove to Midway north of Pueblo, CO for increased thermal capacity.
West Station-Greenhorn 115 kV line rebuild	12.1 miles, Pueblo County, CO	May 2022	$5.0M	West Station 115 kV, Greenhorn 115 kV	115kV; 221 MVA	C18-0843	Rebuild the 115 kV line from West Station to Greenhorn west and south of Pueblo, CO.
Airport Memorial to Nyberg 115 kV Rebuild	5 miles, Pueblo County, CO	Feb. 22, 2021	$3.0M	Airport Memorial 115 kV, Nyberg 115 kV	115 kV; 221 MVA	N/A	Rebuild the 115 kV line from Airport Memorial to Nyberg in Pueblo, CO.
Rodrigues Distribution Sub	Pueblo County, CO	June 2026	$7M	New Rodrigues Substation	115 kV; 25MVA	C19-0638	New 115 kV distribution substation intersecting Reader – Pueblo 115 kV line in Pueblo, CO
Pueblo West Distribution Sub	Pueblo County, CO	July 2023	$5.4M	New Pueblo West Substation	115 kV; 50 MVA	C20-0477	New 115 kV distribution substation in Pueblo West; will intersect the West Station-Hogback 115 kV line in Pueblo West, CO
North Penrose Distribution Substation	Fremont County, CO	Dec. 2022	$6.7M	New N. Penrose Substation	115 kV; 50MVA	C20-0477	New 115 kV distribution substation intersecting the West Station – Hogback 115 kV line near Penrose, CO

All of the projects shown in Table 7-5 and included in Black Hills' 2022 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 in identified by dashed lines.

Figure 7-3

Planned and Conceptual Black Hills Transmission System



7.5 Senate Bill 07-100 Transmission Projects

Colorado Senate Bill 07-100 ("SB 07-100"), codified at § 40-2-126(2), C.R.S. requires rate regulated Colorado utilities to continually evaluate and, if necessary, improve their electric transmission facilities to meet the state's existing 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 ("ERZ");
(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' 2021 SB 07-100 Study[30] (contained within the 2022 10-Year Transmission Plan filed by PSCo, Tri-State, and the Company) evaluated resource injections from ERZ-5 at five 115 kV substations to determine resource injection capability. The five 115 kV substations are listed below:

- Baculite Mesa 115 KV Substation
- Boone 115 kV Substation
- Hogback 115 kV Substation
- Reader 115 kV Substation
- West Station 115 kV Substation

7.5.1 Baculite Mesa 115 kV Substation

Analysis indicated that the Black Hills transmission system could accommodate 150 MW of injection at the Baculite Mesa 115 kV substation with no required upgrades, assuming all planned projects shown in Figure 7-3 are in service. Any injection beyond that will cause overloads on the Baculite Mesa – Airport Memorial Park 115 kV line following the N-2 Contingency of the Baculite Mesa – West Station 115 kV #1 & #2 lines.

7.5.2 Boone 115 kV Substation

Analysis indicated that the Black Hills transmission system could accommodate 160 MW of injection at the Boone 115 kV substation. Higher levels of injection into this substation caused overloads on Xcel's Boone 230/115 kV transformer during the N-2 contingency of the Boone – Nyberg 115 kV line & the Boone – Dot Tap – Nyberg 115 kV line.

[30] *See* Joint 10-Year Transmission Plan, Rev. 2, filed in Proceeding No. 22M-0016E by Public Service Company of Colorado, BHCE, and Tri-State, filed on February 22, 2022, at 93-96.

7.5.3 Hogback 115 kV Substation

Analysis indicated that the Black Hills transmission system could accommodate 100 MW of injection at this location. Higher levels of injection into this substation caused overloads on the Hogback – Cañon West 115 kV line. Injection limits into this area may vary greatly depending on local Cañon City load and proposed transmission upgrades that may occur in the next five-ten years. As injections increased beyond the 100 MW value there were overloads on the Cañon West 230/115 kV transformer, Cañon City – Hogback 115 kV line, Hogback 115/69 kV transformer, Cañon City – Skala 115 kV line, and Portland – Skala 115 kV line.

7.5.4 Reader 115 kV Substation

Analysis indicated that the Reader 115 kV substation could allow for 200 MW of injection; however, this analysis hinges on assumptions that generation retirements and additions in the Comanche area were captured and modelled accurately. Additionally, this injection limit can be impacted by the amount of generation that is entering the system from the Peak View and Rattlesnake wind farms south of the Pueblo system. As generation in the area increases, the risk of overloads in the area will increase following the outage of the Comanche – Daniels Park 345 kV double circuits. In this analysis, the Tundra 345 kV generation was included and flow through the Pueblo 115 kV system was at its peak during the Comanche – Daniels Park 345 kV & Daniels Park – Tundra 345 kV outage. This occurred because outage of the 345 kV backbone from Comanche to Denver area load caused the generation to flow through the underlying 230 and 115 kV systems.

7.5.5 West Station 115 kV Substation

The Company's analysis indicated that the Black Hills Colorado transmission system could accommodate a 200 MW injection at this location. In previous study work, high injections at the West Station substation caused overloads on the Fountain Valley – Midway 115 kV line. A project to rebuild this line and address limiting substation equipment has increased the rating on the line when compared to previous years' studies.

7.5.6 Needed Transmission System Expansion

The 2021 SB 07-100 Report described several projects that would increase the ability of the transmission system to accommodate resource injections[31] from ERZ 5. These projects are described in Table 7-6. The resource injections shown in Table

[31] The 2021 BHCE SB 07-100 Report considered single contingency events when identifying resource injection capability. Injection capability would be reduced when considering all applicable events as identified in NERC Reliability Standard TPL-001-4.

7-6 are non-simultaneous injections that do not take into consideration potential injections from other ERZs.

7.5.7 Desert Cove – Fountain Valley – Midway 115 kV Transmission Line Rebuild

The need to upgrade the capacity of this circuit has been identified in previous planning studies. Especially during periods of high south to north flows across the BHCE 115 kV system which results from high generation in ERZ-5. This project was placed in service January 22, 2021.

7.5.8 Boone – South Fowler 115 kV line & South Fowler 115 kV Substation

This project rebuilt the Boone – South Fowler Tap 69 kV line to 115 kV standards. A new 115 kV substation was built at South Fowler Tap and the line will be energized at 115 kV. This project was identified to support the need for additional transformation in the Rocky Ford area and to provide a location for future voltage support equipment. The study results indicated that this location could support up to 50 MW of generation injection. The project was placed in service in April 20, 2022.

7.5.9 Terminal Additions at All Studied Substation

New terminal additions would be required at substations analyzed as part of this study because no open terminal position currently exist.

Table 7.6 provides a summary of the projects that have been identified as needed to accommodate the resource injections described in section 7.5. The projects identified are conceptual and do include cost estimates or planned in-service dates because they do not exist in Black Hills Colorado's current transmission plan.

Table 7-6
Black Hills 2015 SB-100 Transmission Projects

ERZ	Facility Upgrade Description	Incremental Injection Capability (MW)
5	Replacing the limiting conductor on the Baculite Mesa – Airport Memorial 115 kV line. This project is conceptual, and no in-service date has been assigned	150
5	Upgrade the existing Xcel owned Boone 230/115 kV transformer. This project is conceptual, and no in-service date has been assigned.	160
5	Upgrade the Hogback – Canon West 115 kV line. This project is conceptual, and no in-service date has been assigned.	100
5	Upgrade the Fountain Valley – Midway 115 kV line. This project was completed in January 2021.	200

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 2022 and continuing throughout the RAP. It is anticipated that seasonal firm market purchases and economy energy purchases will be sufficient to cover this deficit until additional resources can be available in 2025.

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 H.

Table 8-1
Load and Resource Balance (2022-2030)

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Demand	443	453	458	465	467	468	469	470	471
DSM	(7.4)	(11.3)	(15.2)	(16.9)	(16.9)	(16.9)	(16.9)	(16.9)	(16.9)
Net Peak Demand	435	442	443	449	450	451	452	453	454
Existing Resources*									
Pueblo Diesels***	8	8	8	8	8	8	8	8	
Airport Diesels***	10	10	10	10	10	10	10	10	10
Rocky Ford Diesels	10	10	10	10	10	10	10		
PAGS LMS100 1	90	90	90	90	90	90	90	90	90
PAGS LMS100 2	90	90	90	90	90	90	90	90	90
Busch Ranch I Ownership**	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Peak View Ownership**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
PAGS LM6000	40	40	40	40	40	40	40	40	40
Total Resources	258	258	258	258	258	258	258	248	240
Contract Purchases*									
PAGS CC PPA	200	200	200	200	200	200	200	200	200
MPS	5	5	5						
Busch Ranch I PPA**	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Busch Ranch II PPA**	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Total Purchases	215	215	215	210	210	210	210	210	210
Total Resources and Purchases	473	473	473	468	468	468	468	458	450
24% Reserve Margin (MW)	105	106	106	108	108	108	108	109	109
Total Capacity Requirement (peak plus reserves)	540	548	549	556	558	559	560	562	563
Total Resources minus Total Capacity Requirement									
In MW	(66.6)	(74.4)	(75.4)	(87.8)	(89.3)	(90.6)	(92.0)	(103.3)	(112.6)
As a percentage	(12.2)	(13.5)	(13.6)	(15.7)	(15.9)	(16.1)	(16.3)	(18.3)	(19.9)
Notes:									
*Summer rated capacities shown.									
**13.57% of all existing wind resources count as accredited capacity.									
*** The Pueblo and Airport Diesel units are proposed to early retire in 2025.									

8.2 Analysis

Capacity expansion and production cost modeling was 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 E3's RESOLVE and the PLEXOS 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 J.

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 8.6. In total, the Company modeled 23 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 will be proposing to implement a new cost recovery mechanism, in 2026, called the Clean Energy Plan Rider ("CEPR") to recover the additional cost of its CEP, consistent with C.R.S 40-2-125.5(5)(a)(I) which states: "The commission shall establish a maximum electric retail rate impact of one and one-half percent of the total electric bill annually for each customer for implementation of the approved additional clean energy plan activities, consistent with this subsection (5)."

The CEPR will be a 1.5% surcharge on all customer bills. To determine the "additional" clean energy plan activities, the Company compared the Base ERP No SCC scenario to the CEP scenario. Table 8-2 below compares the resource acquisitions and the cost between these two scenarios. Additional detail describing these costs can be found in Appendix A.

Table 8-2
CEP Additional Cost

Cost	2026	2027	2028	2029	2030
Base ERP No SCC					
Wind	$0	$0	$0	$0	$0
Solar	$9,677,615	$9,677,615	$9,677,615	$9,677,615	$9,677,615
Battery	$681,981	$681,981	$681,981	$681,981	$681,981
Natural Gas					
CEP					
Wind	$777,021	$777,021	$777,021	$777,021	$21,082,381
Solar	$15,143,131	$15,143,131	$15,143,131	$15,143,131	$15,143,131
Battery	$4,923,000	$4,923,000	$4,923,000	$4,923,000	$4,923,000
Additional Cost					
Wind	$777,021	$777,021	$777,021	$777,021	$21,082,381
Solar	$5,465,517	$5,465,517	$5,465,517	$5,465,517	$5,465,517
Battery	$4,241,019	$4,241,019	$4,241,019	$4,241,019	$4,241,019
Total	$10,483,556	$10,483,556	$10,483,556	$10,483,556	$30,788,916

In addition, C.R.S 40-2-125.5(4)(a)(VIII) allows the utility to use up to one-half of the funds collected annually through the Company's Renewable Energy Standard Adjustment ("RESA") as well as any accrued funds in the RESA to recover the incremental cost of its CEP. The Company does not anticipate a need to use up to one half of the annual RESA funds, but the Company is proposing to use half of the accrued RESA balance to fund its CEP. By the end of 2022, the Company projects the RESA balance will be over collected by approximately $13.4 million. The Company proposes to use half of this amount or approximately $6.7 million to fund the CEP.

The CEPR will collect annual revenues of approximately $4.25 million, however the additional or incremental costs of the CEP are approximately $10.5 million annually, as shown in the table above. This creates a shortfall in funding. The Company will add interest equal to its Commission authorized weighted average cost of capital. By 2030, the Company projects this accumulated under-recovery of costs will total approximately $53.6 million. Table 8-3 below compares the CEPR Recovery to the Total CEP Incremental Cost.

Table 8-3
CEPR Recovery Comparison to Total CEP Incremental Cost

Cost	RESA Transfer	2026	2027	2028	2029	2030
Total Revenues						
CEPR Revenues	$6,675,777	$4,255,155	$4,297,707	$4,340,684	$4,384,090	$4,427,931
Additional CEP Cost		$10,487,474	$10,487,474	$10,487,474	$11,103,474	$30,788,917
Interest		$35,160	($432,312)	($913,009)	($1,449,493)	($2,787,462)
CEPR Balance	$6,675,777	($2,613,521)	($9,235,600)	($16,295,399)	($24,464,276)	($84,865,420)

C.R.S 40-2-125.5(5)(A)(V) states:

> **(V)** In the first rate case following the final implementation of the clean energy plan, the commission shall conduct a final reconciliation of the clean energy plan revenue rider and determine how to account for any positive or negative rider balance. In the manner determined by the commission, any remaining positive balance shall be returned to customers or used to reduce customer rates and any negative balance shall be incorporated into the qualifying retail utility's rates.

The Company anticipates that the final implementation of the CEP will occur when the last resource is online, thus in 2030 any negative balance will be incorporated into the Company's rates at that time.

The Company is also proposing several modifications to its RESA. The Company's RES Plan discusses these changes in more detail. The culmination of these changes will allow the Company to reduce its RESA surcharge from 2% down to 1% beginning in 2023 and continuing through 2026. The Company will file a new RES Plan in 2026 and will address the funding needs for 2027-2030 at that time.

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. 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[32]
- Base natural gas, hydrogen, and economy energy forecasts[33]
- Seasonal firm market purchases up to 50 MW
- Conventional and renewable energy resource options[34]

[32] Described in "Base Peak Demand and Annual Energy Forecasts" in Section 4.4
[33] Described in "Fuel and Market Prices" in Section 3.4
[34] Described in "Candidate Resource Options" in Section 5.4

8.6 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 core 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:

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”
3. Clean Energy Plan (CEP) Scenario
    - Investigated the impact meeting Clean Energy Plan requirements would have on the Base ERP resource portfolio
    - Required 80% $CO2$ emissions reduction by 2030 and 100% clean energy by 2050
    - 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”
5. C&I Generation CEP Scenario
    - Investigated the impact Industrial Generation would have on the CEP resource portfolio
    - Added Industrial Generation resource to the CEP portfolio
    - Assumed all other modeling variables as described in “CEP Scenario”
6. C&I Generation CEP No SCC Scenario
    - Investigated the impact Industrial Generation and no SCC and no SCM would have on the CEP resource portfolio
    - Added Industrial Generation resource to the CEP no SCC portfolio
    - Removed the SCC and SCM
    - Assumed all other modeling variables as described in “CEP Scenario”

7. C&I Generation CEP Organized Wholesale Market Scenario
    - Investigated the impact increased market availability and sales market would have on the CEP resource portfolio; this simulates a directional impact of organized wholesale markets
    - Replaced the 100 MW economy energy purchase markets with 200 MW economy energy purchase markets
    - Added a 100 MW economy energy sales market
    - Assumed all other modeling variables as described in "CEP Scenario"
8. 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"
9. CEP with Turkey Creek[35] Scenario
    - Investigated the impact of adding Turkey Creek to the existing resources would have on the CEP resource portfolio
    - Added Turkey Creek from available existing resources
    - Assumed all other modeling variables as described in "CEP Scenario"
10. CEP No SCC with Turkey Creek Scenario
    - Investigated the impact no SCC and no SCM would have on the CEP with Turkey Creek resource portfolio
    - Removed the SCC and SCM assumptions
    - Assumed all other modeling variables as described in "CEP with Turkey Creek Scenario"
11. C&I Generation CEP with Turkey Creek Scenario
    - Investigated the impact Industrial Generation would have on the CEP with Turkey Creek resource portfolio
    - Added Industrial Generation resource to the CEP with Turkey Creek portfolio
    - Assumed all other modeling variables as described in "CEP with Turkey Creek Scenario"
12. C&I Generation CEP No SCC with Turkey Creek Scenario
    - Investigated the impact Industrial Generation and no SCC and no SCM would have on the CEP with Turkey Creek resource portfolio
    - Added Industrial Generation resource to the CEP with Turkey Creek portfolio
    - Removed the SCC and SCM assumptions
    - Assumed all other modeling variables as described in "CEP with Turkey Creek Scenario"

[35] At the time the modeling was completed, Black Hills was in good faith negotiations with TC Colorado. The Turkey Creek Scenarios are provided for informational purposes, and the Company's Preferred Plan no longer includes the Turkey Creek Project.

13. C&I Generation CEP Organized Wholesale Market with Turkey Creek Scenario
    - Investigated the impact increased market availability and sales market would have on the CEP with Turkey Creek resource portfolio
    - Replaced the 100 MW economy energy purchase markets with 200 MW economy energy purchase markets
    - Added a 100 MW economy energy sales market
    - Assumed all other modeling variables as described in "CEP with Turkey Creek Scenario"
14. CEP Increased Electrification with Turkey Creek Scenario
    - Investigated the impact increased electrification would have on the CEP with Turkey Creek 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 with Turkey Creek Scenario"
15. Low Load Scenario
    - Investigated the impact lower than forecasted load growth would have on the CEP with Turkey Creek resource portfolio
    - Replaced the base load forecast with the low load forecast
    - Assumed all other modeling variables as described in "CEP with Turkey Creek Scenario"
16. High Load Scenario
    - Investigated the impact higher than forecasted load growth would have on the CEP with Turkey Creek resource portfolio
    - Replaced the base load forecast with the high load forecast
    - Assumed all other modeling variables as described in "CEP with Turkey Creek Scenario"
17. Low Gas Scenario
    - Investigated the impact low natural gas prices would have on the CEP with Turkey Creek 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 with Turkey Creek Scenario"

18. High Gas Scenario
    - Investigated the impact high natural gas prices would have on the CEP with Turkey Creek 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 with Turkey Creek Scenario”
19. Low Hydrogen Scenario
    - Investigated the impact low hydrogen prices would have on the CEP with Turkey Creek resource portfolio
    - Replaced the base hydrogen forecast with the low hydrogen forecast
    - Assumed all other modeling variables as described in “CEP with Turkey Creek Scenario”
20. No New Renewables Scenario
    - Investigated the impact no renewable builds would have on the Base ERP resource portfolio
    - Allowed only gas builds to fill capacity deficits
    - Existing wind and solar resources are assumed to be re-contracted
    - Removed the SCC and SCM assumptions
    - Assumed all other modeling variables as described in “Base ERP Scenario”
21. Base ERP with Turkey Creek Scenario
    - Investigated the impact of adding Turkey Creek to the existing resources would have on the Base ERP resource portfolio
    - Added Turkey Creek from available existing resources
    - Assumed all other modeling variables as described in “Base ERP Scenario”
22. Base ERP No SCC with Turkey Creek Scenario
    - Investigated the impact of adding Turkey Creek to existing resources and no SCC and no SCM would have on the Base ERP resource portfolio
    - Added Turkey Creek from available existing resources
    - Removed the SCC and SCM assumptions
    - Assumed all other modeling variables as described in “Base ERP Scenario”
23. No New Renewables with Turkey Creek Scenario
    - Investigated the impact of adding Turkey Creek to existing resources and no renewable builds would have on the Base ERP resource portfolio
    - Added Turkey Creek from available existing resources
    - Allowed only gas builds to fill capacity deficits
    - Existing wind and solar resources are assumed to be re-contracted

- Removed the SCC and SCM assumptions
- Assumed all other modeling variables as described in "Base ERP Scenario"

The two core 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. Table 8-4 and Table 8-5 summarize the assumptions used for each scenario.

Table 8-4
Core Scenario Characteristics Summary

	Base ERP	**CEP**
Scenario Description	Base Energy Resource Plan without Emissions Constraint	Clean Energy Plan with 80% reduction of 2005 baseline CO2 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
Hydrogen Price	Base	Base
Social Cost of Carbon Adder	Yes	Yes
Methane Cost Adder	Yes	Yes
Emissions Targets	None	Yes
Turkey Creek	None	None
Model	RESOLVE	RESOLVE/PLEXOS

Table 8-5
Sensitivity Scenario Characteristics Summary

Scenario	Base ERP without SCC	CEP without SCC	Base ERP with Turkey Creek	CEP with Turkey Creek	Increased Electrificatio n	Low Hyrdroge n	Low Load	High Load	Low Fuel	High Fuel	No New Renewables	C&I Generation CEP	C&I Generation CEP without SCC	C&I Generation CEP with OWM
Description	Base ERP scenario with no social cost of carbon or social cost of methane applied	CEP scenario with no social cost of carbon or social cost of methane applied	Base ERP with Turkey Creek	CEP with Turkey Creek	CEP scenario with additional load growth from electrification	CEP scenario with low hydrogen cost	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	The No New Renewables scenarios does not allow any new renewable resource build	CEP portfolio with additional industrial electrification	C&I Gen CEP portfolio without social cost of carbon or social cost of methane	C&I Gen CEP portfolio with doubled purchase markets (200 MW) and added sales market (100 MW)
Core Scenario	Base ERP/Base ERP with TC	CEP/CEP with TC	Base ERP	CEP	CEP/CEP with TC	CEP with TC	CEP with TC	CEP with TC	CEP with TC	CEP with TC	Base ERP/Base ERP with TC	CEP/CEP with TC	CEP/CEP with TC	CEP/CEP with TC
Load Growth	Base	Base	Base	Base	Base	Base	Low	High	Base	Base	Base	Base	Base	Base
Electric Vehicle	None	None	None	None	Yes	None	None	None	None	None	None	None	None	None
Building Electrificatio n	None	None	None	None	Yes	None	None	None	None	None	None	None	None	None
Electric Price	Base	Base	Base	Base	Base	Base	Base	Base	Low	High	Base	Base	Base	Base
Gas Price	Base	Base	Base	Base	Base	Base	Base	Base	Low	High	Base	Base	Base	Base
Hydrogen Price	Base	Base	Base	Base	Base	Low	Base	Base	Base	Base	Base	Base	Base	Base
Social Cost of Carbon Adder	None	None	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	None	Yes	None	Yes
Methane Cost Adder	None	None	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	None	Yes	None	Yes
Emissions Targets	None	Yes	None	Yes	Yes	Yes	Yes	Yes	Yes	Yes	None	Yes	Yes	Yes
Industrial Solar	None	None	None	None	None	None	None	None	None	None	None	80 MW total with 20 MW added in 2025, 2026, 2027 and 2028	80 MW total with 20 MW added in 2025, 2026, 2027 and 2028	80 MW total with 20 MW added in 2025, 2026, 2027 and 2028
Model	RESOLVE	RESOLVE	RESOLVE	RESOLVE	RESOLVE	RESOLVE	RESOLVE	RESOLVE	RESOLVE	RESOLVE	RESOLVE	PLEXOS	PLEXOS	PLEXOS

The resource portfolios for scenarios add varying amounts of wind, solar, and storage during the RAP. Gas and SFMP additions support the wind, solar, and storage additions as depicted in the appropriate scenarios. Capacity Expansion modeling results (5-year incremental resource portfolios) for these scenarios are shown in Table 8-6.

Table 8-6
Optimal Expansion Plans – Scenario Analysis
5-year Incremental Additions (MW)

Scenario		2025	2030	2035	2040	2045	2050
Base ERP	Wind	0	145	5	29	107	2
	Solar	249	0	89	19	49	101
	Storage	32	0	150	9	3	85
	Gas	0	0	123	2	4	160
	SFMP	0	0	0	0	0	0
Base ERP No SCC	Wind	0	0	56	58	138	35
	Solar	165	45	83	3	48	64
	Storage	7	39	102	0	2	77
	Gas	13	0	136	0	0	156
	SFMP	15	0	0	0	0	0
CEP	Wind	5	144	1	29	107	14
	Solar	258	0	80	19	49	175
	Storage	50	0	132	9	3	163
	Gas	0	0	123	2	4	137
	SFMP	0	0	0	0	0	0
CEP No SCC	Wind	0	29	38	60	149	13
	Solar	166	56	72	10	36	251
	Storage	10	40	100	0	0	222
	Gas	12	0	135	0	0	117
	SFMP	31	0	0	0	0	0
C&I Generation CEP*	Wind	5	144	1	29	107	14
	Solar	258	0	80	19	49	175
	Storage	50	0	132	9	3	163
	Gas	0	0	123	2	4	137
	SFMP	0	0	0	0	0	0
C&I Generation CEP No SCC*	Wind	5	144	1	29	107	14
	Solar	258	0	80	19	49	175
	Storage	50	0	132	9	3	163
	Gas	0	0	123	2	4	137
	SFMP	0	0	0	0	0	0
C&I Generation CEP OWM*	Wind	5	144	1	29	107	14
	Solar	258	0	80	19	49	175
	Storage	50	0	132	9	3	163
	Gas	0	0	123	2	4	137
	SFMP	0	0	0	0	0	0
CEP Increased Elec	Wind	0	210	45	93	170	65
	Solar	300	6	92	82	190	145
	Storage	62	38	94	67	141	85

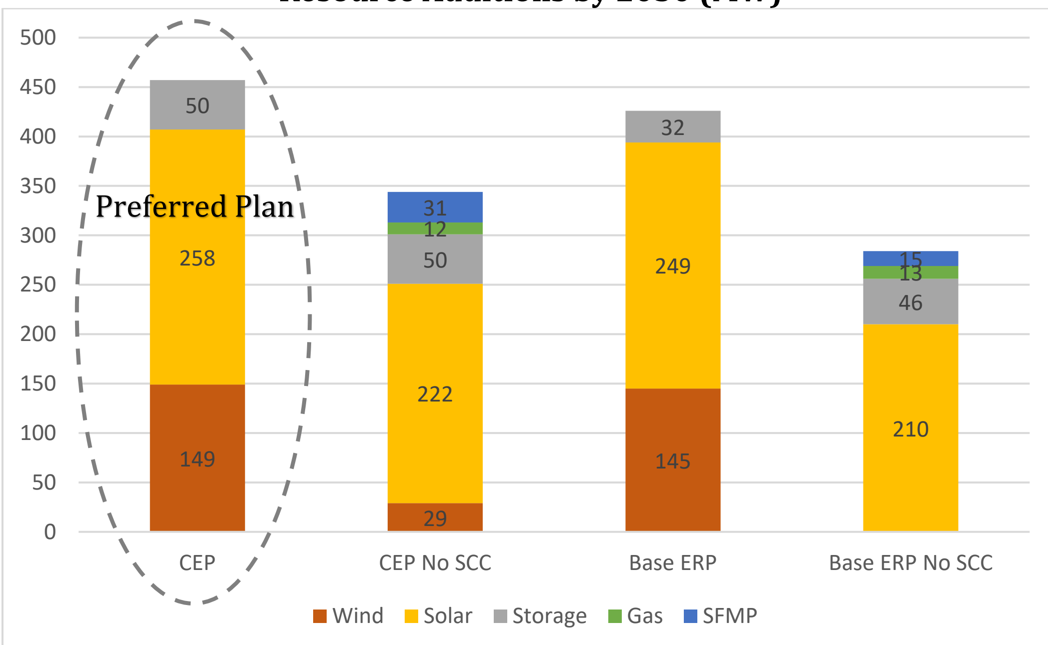
Scenario		2025	2030	2035	2040	2045	2050
	Gas	0	0	290	143	90	238
	SFMP	0	0	0	0	0	0
CEP with TC	Wind	25	117	13	34	101	34
	Solar	103	0	72	186	48	152
	Storage	54	0	112	16	4	138
	Gas	0	0	129	0	5	141
	SFMP	0	0	0	0	0	0
CEP NoSCC with TC	Wind	0	13	68	54	143	46
	Solar	14	61	51	186	29	220
	Storage	10	40	100	0	0	174
	Gas	26	0	123	0	0	126
	SFMP	31	0	0	0	0	0
C&I Generation CEP with TC*	Wind	25	117	13	34	101	34
	Solar	103	0	72	186	48	152
	Storage	54	0	112	16	4	138
	Gas	0	0	129	0	5	141
	Ind. Gen.	20	60	0	0	0	0
	SFMP	0	0	0	0	0	0
C&I Generation CEP NoSCC with TC*	Wind	25	117	13	34	101	34
	Solar	103	0	72	186	48	152
	Storage	54	0	112	16	4	138
	Gas	0	0	129	0	5	141
	Ind. Gen.	20	60	0	0	0	0
	SFMP	0	0	0	0	0	0
C&I Generation CEP OWM with TC*	Wind	25	117	13	34	101	34
	Solar	103	0	72	186	48	152
	Storage	54	0	112	16	4	138
	Gas	0	0	129	0	5	141
	Ind. Gen.	20	60	0	0	0	0
	SFMP	0	0	0	0	0	0
CEP Increased Elec with TC	Wind	4	202	46	97	172	73
	Solar	137	0	109	233	190	132
	Storage	74	26	90	66	120	71
	Gas	0	0	289	142	95	234
	SFMP	0	0	0	0	0	0
Low Load	Wind	15	115	20	13	100	34
	Solar	93	0	79	163	29	146
	Storage	47	0	125	0	0	126
	Gas	0	0	92	0	0	125
	SFMP	0	0	0	0	0	0
High Load	Wind	25	131	18	36	106	34
	Solar	118	0	63	186	70	188
	Storage	67	5	85	28	5	169
	Gas	0	0	169	9	17	148
	SFMP	0	0	0	0	0	0
Low Gas	Wind	25	82	43	27	96	51
	Solar	100	0	49	186	9	217

Scenario		2025	2030	2035	2040	2045	2050
	Storage	55	0	95	5	0	169
	Gas	0	0	136	4	8	127
	SFMP	0	0	0	0	0	0
High Gas	Wind	50	118	0	26	118	12
	Solar	111	0	85	225	13	127
	Storage	46	20	122	3	14	119
	Gas	0	0	119	4	2	150
	SFMP	0	0	0	0	0	0
Low Hydrogen	Wind	25	117	11	29	108	11
	Solar	103	0	72	186	48	75
	Storage	54	0	112	18	2	79
	Gas	0	0	129	0	5	160
	SFMP	0	0	0	0	0	0
No New Renewables	Wind	0	0	0	29	121	0
	Solar	0	0	0	0	0	0
	Storage	0	0	0	0	0	0
	Gas	55	0	208	5	55	135
	SFMP	25	17	8	0	0	50
Base ERP with TC	Wind	8	133	12	29	108	1
	Solar	95	0	80	186	48	92
	Storage	41	0	125	18	2	86
	Gas	0	0	129	0	5	159
	SFMP	0	0	0	0	0	0
Base ERP NoSCC with TC	Wind	0	0	74	53	126	42
	Solar	14	40	73	186	31	80
	Storage	8	35	107	0	0	60
	Gas	29	0	122	0	2	157
	SFMP	12	0	0	0	0	0
No New Renewables with TC	Wind	0	0	0	29	121	0
	Solar	0	0	0	186	0	0
	Storage	0	0	0	0	0	0
	Gas	51	24	216	5	5	185
	SFMP	0	0	0	0	0	0

* C&I Generation CEP was run in PLEXOS only. The RESOLVE builds are the CEP Scenario builds plus Industrial Generation

The resource portfolios for CEP and ERP scenarios add varying amounts of wind, solar, and storage during the RAP. Smaller amounts of gas and SFMP additions support the wind, solar, and storage additions in the No SCC scenarios. Capacity Expansion modeling results for CEP and ERP scenarios, both with and without the SCC are provided in Figure 8-1.

Figure 8-1
Optimal Expansion Plans – CEP and ERP Scenario Analysis
Resource Additions by 2030 (MW)



Present Value Revenue Requirements ("PVRR") were calculated for each of the twenty-three scenarios using the scenario assumptions as described above. The PVRRs for the scenario analysis are shown on Figure 8-2 and Figure 8-3, where the grey shaded portions represent the social cost of carbon.

Figure 8-2
Base ERP and Scenarios – Deterministic PVRRs (2022-2050)
27 Year PVRR ($MM)

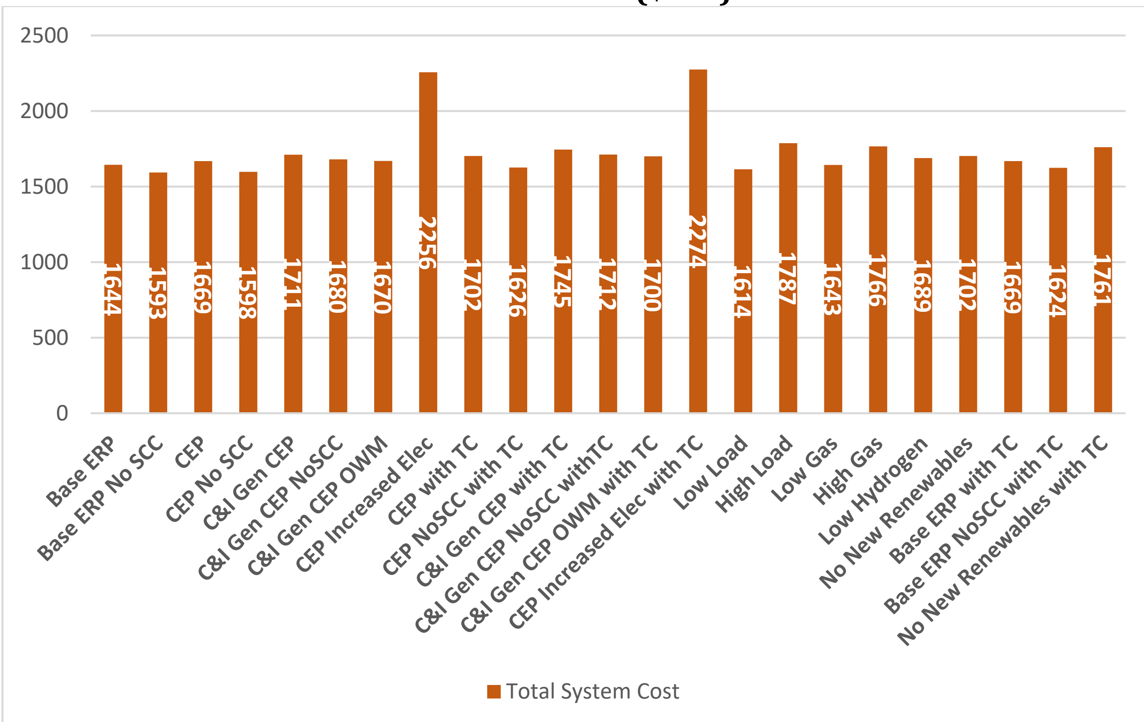
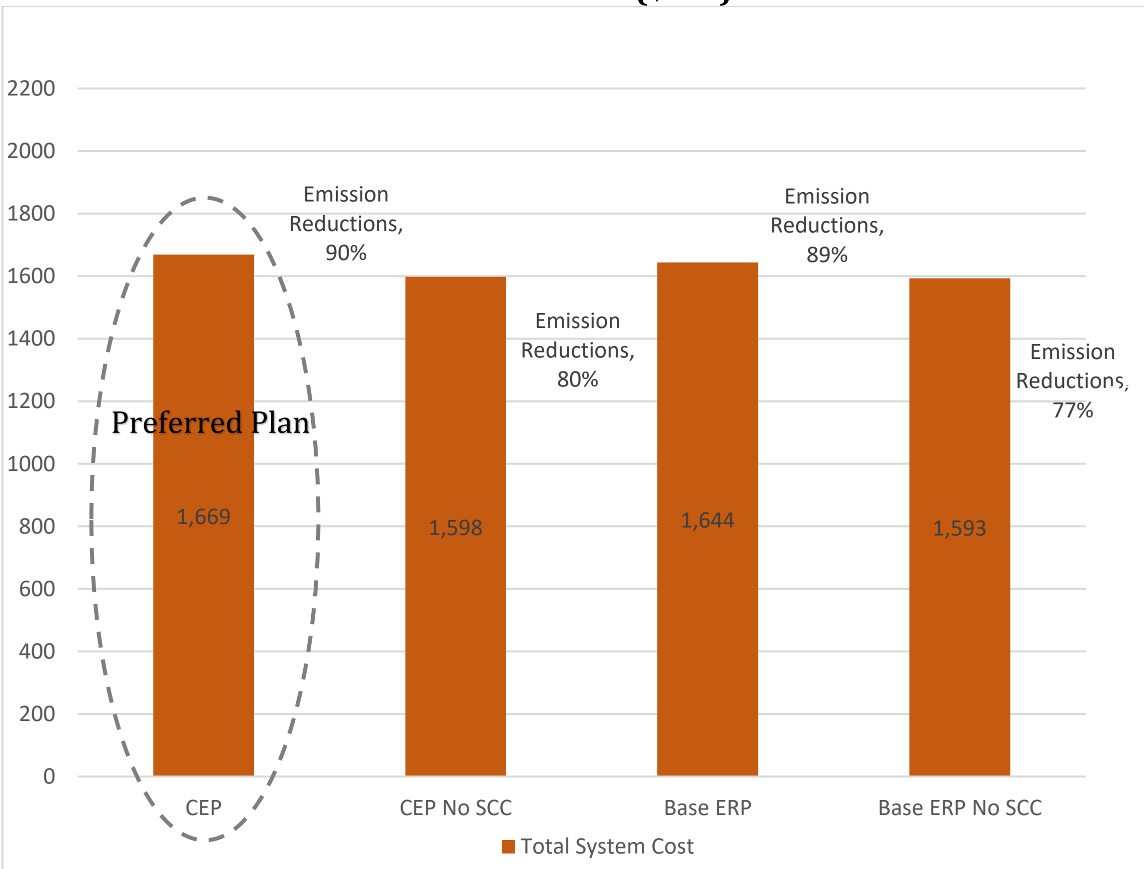


Figure 8-3
Base ERP and Key Scenarios – Deterministic PVRRs (2022-2050)
27 Year PVRR ($MM)



The least-cost portfolio based on the PVRR analysis is the Base ERP No SCC scenario, however it only achieves 77 percent greenhouse gas emission reduction by 2030. During the RAP, the CEP and Base ERP scenarios have similar portfolios. Likewise, the RAP portfolios for CEP with Turkey Creek and Base ERP with Turkey Creek scenarios are similar. The SCC scenarios inherently have higher costs than the No SCC scenarios due to the inclusion of the additional costs. The inclusion of these costs, as well as the modeling requirement to meet the 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 a social cost 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 scenarios are significantly higher than the other portfolios indicating increased customer cost.

8.7 Preferred Plan

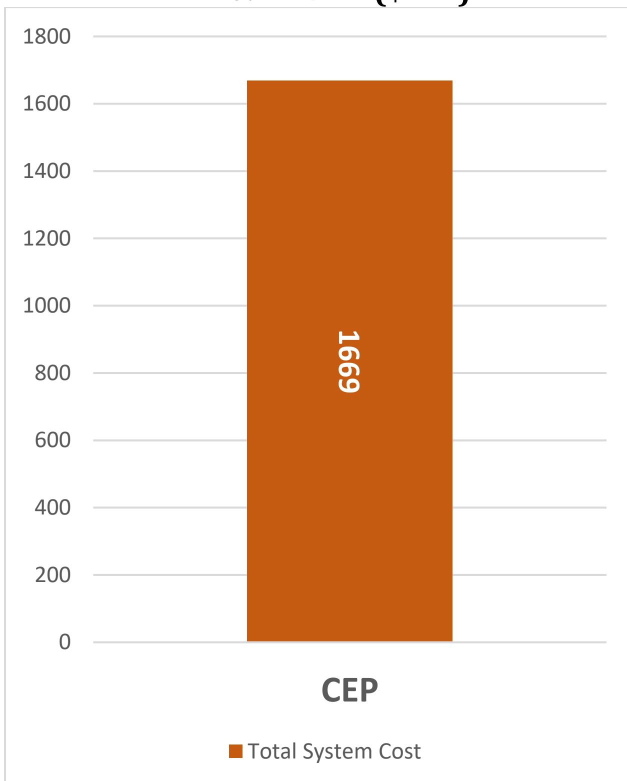
As a result of the load and resource balance, capacity expansion, production cost modeling, and retail rate impact evaluations, Black Hills is recommending the Clean Energy Plan (with social costs) scenario as the Preferred Plan as it cost effectively achieves Colorado's state policy objectives. The Preferred Plan's PVRR is shown in Figure 8-4. The Preferred Plan is estimated to achieve 90 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.

Beyond the RAP, Black Hills' load and resource balance continues to show a capacity deficit which expands in 2032 when the Company's contract for 200 MW of generation expires. The modeling identified an optimal portfolio to replace this expiring contract, 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 for this contract.

Black Hills' Preferred Plan recommends that the Company engage in a Phase II competitive solicitation to acquire about 450 MW of renewable energy resources in combination with storage by 2030. The modeling supports this recommendation in the CEP scenario which identifies a need for 149 MW of wind, 258 MW of solar, and 50 MW of storage by 2030. The exact capacity mix of these resources will be further refined in the Phase II analysis of this proceeding. 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 or even exceed the 80 percent emissions reduction by 2030.

The planning assumptions used in this Plan will underlie the evaluation of proposals received in response to a Company solicitation in a Phase II of this Plan Proceeding. The Company has included a list of General Planning Assumptions in Appendix I that were used in the ERP modeling and will be used in a 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 those assumptions that will be updated for the evaluation of proposals.

Figure 8-4
Preferred Plan Scenario – Deterministic PVRRs (2022-2050)
27 Year PVRR ($MM)



8.8 2023 through 2026 RES Compliance Plan

The Company is filing, concurrently with this 2022 ERP, its 2023 through 2026 RES Compliance Plan. The RES Plan is being filed by Black Hills pursuant to the RES established by the RES Statute and implemented by the RES Rules. The RES Plan details how the Company will comply with the RES Rules covering compliance years 2023 through 2026, the RAP, and the 10-year RES Compliance Period.

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 the acquisition of (1) additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to Rule 3610, or (2) replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under Rule 3617.[36]

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

36 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.

2. Arrange for temporary generation
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 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
- 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
- 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

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
- System Emissions
  - CO_2
  - SO_2
  - NO_x
  - 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
- Monthly On/Off Peak Market Prices
- Market Emission Assumptions
- Unit Variable O&M
- Unit Fixed O&M
- Fuel Costs
- Unit Contribution to Spinning Reserve
- SO_2 Pricing
- NO_x Pricing
- CO_2 Pricing
- Unit Emission Rates
  - SO_2
  - NO_x
  - CO_2
  - Mercury
- 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
- PPA Emission Rates
  - CO_2
  - SO_2
  - NO_x
  - Mercury
- Hourly Wind Patterns
- Hourly Solar Patterns
- Generic Renewable Resources
  - Capital Costs
  - Fixed O&M
  - Variable O&M

11.2.2 Modeling Output Data

- Unit Level Generation
- Unit Level Capacity Factors
- Unit Level Fuel Consumed
- Unit Level Average Heat Rate
- Unit Level Total Variable O&M
- Unit Level Fixed O&M
- Fuel Cost
  - Coal Cost Projection
  - 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
- PPA Capacity Factors
- PPA Total Energy Payments (subject to contractual limitations)
- PPA Total Capacity Payments (subject to contractual limitations)
- PPA Emissions
  - NO_x
  - SO_2
  - CO_2
  - Mercury

11.3 Highly Confidential Information

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

- Unit Level Delivered Fuel Costs
- Hourly Market Price Data
- Unit Level 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 2018 and the gallons consumed per MWh, also known as water intensity, for the current generation fleet.

Table 14-1
Water Resources – Existing Generating Facilities

Unit Name	Fuel Type	2018 Energy Produced (MWh)	2018 Water Consumption (gallons)	Water Intensity (gallons/MWh)
PAGS CT 1	Nat Gas	153,051	29,184,865	191
PAGS CT 2	Nat Gas	58,986	11,349,966	192
LM6000	Nat Gas	16,043	1,357,089	85
Pueblo Diesels	#2 Oil	Negligible	Negligible	Negligible
Airport Diesels	#2 Oil	Negligible	Negligible	Negligible
Rocky Ford Diesels	#2 Oil	Negligible	Negligible	Negligible
Annual Total			296,519,197	

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 90 percent capacity factor, as indicated in the table, for the possible resources.

Table 14-2
Water Resources – Potential Generating Facilities

Unit Name	Fuel Type	Annual Water Intensity (Gallons/MWh)	Annual Water Consumption (Gallons)
LM2500 (30% Capacity Factor)	75% Hydrogen Cofiring	91	7,174,440
LM6000 (30% Capacity Factor)	35% Hydrogen Cofiring	83	9,379,332
LMS100 (30% Capacity Factor)	30% Hydrogen Cofiring	166	42,316,056
Geothermal (80% Capacity Factor)	Geothermal	238	66,742,857
SMR (90% Capacity Factor)	SMR	558	439,927,200

15.0 Conclusion

The Company is pleased to present its 2030 Ready 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
Estimated CEP Additional Cost Tables

Schedule A-1: 2026-2030 Estimated CEP Additional Cost of Wind Resources
Schedule A-2: 2026-2030 Estimated CEP Additional Cost of Solar Resources
Schedule A-3: 2026-2030 Estimated CEP Additional Cost of Storage Resources

Appendix B
Base Econometric Load Forecast Methodology

See separate appendix.

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

Schedule B-1	Monthly Historical Demand Data
Schedule B-2	Monthly Historical Class Sales Data
Schedule B-3	Annual Historical and Forecasted Economic Data
Schedule B-4	Historical and Forecasted Weather Data Used in Demand Model
Schedule B-5	Historical and Forecasted Weather Data Used in Sales Models
Schedule B-6	Historical and Forecasted Variable Values for Demand Model
Schedule B-7	Variable Statistical Values for Demand Model
Schedule B-8	Base Monthly Class-Level Sales Forecasts and Demand Forecast
Schedule B-9	Base Annual Class-Level Sales Forecasts and Demand Forecast
Schedule B-10	Historical and Forecasted Variable Values for Residential Use Per Customer Model
Schedule B-11	Variable Statistical Values for Residential Use Per Customer Model
Schedule B-12	Historical and Forecasted Variable Values for Residential Customer Model
Schedule B-13	Variable Statistical Values for Residential Customer Model
Schedule B-14	Historical and Forecasted Variable Values for Small General Service Use Per Customer Model
Schedule B-15	Variable Statistical Values for Small General Service Use Per Customer Model
Schedule B-16	Historical and Forecasted Variable Values for Small General Service Customer Model
Schedule B-17	Variable Statistical Values for Small General Service Customer Model
Schedule B-18	Historical and Forecasted Variable Values for Large General Service Use Per Customer Model
Schedule B-19	Variable Statistical Values for Large General Service Use Per Customer Model
Schedule B-20	Historical and Forecasted Variable Values for Large General Service Customer Model
Schedule B-21	Variable Statistical Values for Large General Service Customer Model
Schedule B-22	Historical and Forecasted Variable Values for Large Power Service Sales Model
Schedule B-23	Variable Statistical Values for Large Power Service Sales Model
Schedule B-24	Historical and Forecasted Variable Values for Large Power Service Customer Model
Schedule B-25	Variable Statistical Values for Large Power Service Customer Model

Appendix C
Net BTM Solar Load Forecast

See separate appendix.

Appendix D
Daily Load Profiles

See separate appendix.

Schedule D-1	January
Schedule D-2	February
Schedule D-3	March
Schedule D-4	April
Schedule D-5	May
Schedule D-6	June
Schedule D-7	July
Schedule D-8	August
Schedule D-9	September
Schedule D-10	October
Schedule D-11	November
Schedule D-12	December

Appendix E
Technology Characterization and Busbar Cost Analysis

See separate appendix.

Appendix F
E3 Technical Report

See separate appendix.

Appendix G
NREL Annual Technology Baseline Report

is available at:

https://atb-archive.nrel.gov/electricity/2020/files/2020-ATB-Data.xlsm

Appendix H
2022 - 2050 Load and Resource Balance

See separate appendix.

Appendix I
General Planning Assumptions

The planning assumptions shown on Table I-1 will underlie the evaluation of proposals received in response to any Company solicitation in Phase II of these 2022 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 certain of these assumptions are altered in accordance with Commission directives.

Table I-1
General Planning Assumptions

Item	2022 ERP Assumption	Updated in Phase II
Capacity credit for solar	See Section 6.3	No
Capacity credit for wind	See Section 6.3	No
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	Yes
Cost of integrating renewable resources	See Section 6.1	Yes
DSM forecast	See Section 3.7	Yes
Social costs of emissions	See Section 3.6	No
Financial parameters	See Table 3-6	No
General inflation rate	1.5%	If appropriate
Load forecast	See Section 4.0	No
Market prices	Confidential HAPG forecast	Yes
Natural gas prices	Confidential HAPG forecast	Yes
Existing unit operating characteristics and costs	See Table 5-1,5-2, and Appendix F	No
Existing unit retirement dates	See Table 5-1,5-2, and Appendix F	No
Planning period	29 years	No
Planning reserve margin	24% minimum	No
Power purchase contracts	Varies by resource	No
Resource Acquisition Period	9 years	No
Seasonal firm market purchases	See Section 3.4.5	No

Appendix J
Computer Modules Used for the Electric Resource Plan

In developing resource plans for Black Hills, E3 conducted capacity expansion simulations using E3's RESOLVE model and system operations simulations using PLEXOS. Summary Descriptions of the two models are included below. Detailed descriptions are included in Appendix F.

Resolve Model Overview

RESOLVE is a resource investment 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 capacity expansion questions for systems seeking to integrate large quantities of variable resources, RESOLVE layers capacity expansion logic on top of a production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. 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. RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. In general, the options for new investments considered in this study are limited to those technologies that are commercially available today. This approach ensures that the greenhouse gas reduction portfolios developed in this study can be achieved without relying on assumed future technological breakthroughs. This modeling choice is not meant to suggest that such emerging technologies should not have a role in meeting regional greenhouse gas reduction goals, but instead reflects a simplifying assumption made in this study.

Operational Simulation

To identify optimal investments in the electric sector, maintaining a robust representation of prospective resources' impact on system operations is fundamental to ensuring that the value each resource provides to the system is captured accurately. At the same time, the addition of investment decisions across multiple periods to a traditional unit commitment problem increases its computational complexity significantly. RESOLVE's simulation of operations has therefore been carefully designed to simplify a traditional unit commitment problem, where possible, while maintaining a level of detail sufficient to provide a reasonable valuation of potential new resources. The key attributes of RESOLVE's operational simulation are enumerated below:

- Hourly chronological simulation: RESOLVE's representation of system operations uses an hourly resolution to capture the intraday variability of load and renewable generation. This level of resolution is necessary in a planning-level study to capture the intermittency of potential new wind and solar resources, which are not available at all times of day to meet demand and must be supplemented with other resources.

- Aggregated generation classes: Rather than modeling each generator within the study footprint independently, generators in each region are grouped together into categories with other plants whose operational characteristics are similar (e.g. nuclear, coal, gas combined cycle, gas combustion turbine). Grouping like plants together for the purpose of simulation reduces the computational complexity of the problem without significantly impacting the underlying economics of power system operations.
- Linearized unit commitment: RESOLVE includes a linear version of a traditional production simulation model. In RESOLVE's implementation, this means that the commitment variable for each class of generators is a continuous variable rather than an integer variable. Additional constraints on operations (e.g., Pmin, Pmax, ramp rate limits, minimum up and down time) further limit the flexibility of each class's operations.
- Co-optimization of energy and ancillary services: RESOLVE dispatches generation to meet load across the modeled regions, while simultaneous reserving flexible capacity to meet the contingency and flexibility reserve needs. As systems become increasingly constrained on flexibility, the inclusion of ancillary service needs in the dispatch problem is necessary to ensure a reasonable dispatch of resources that can serve load reliably.
- Smart sampling of days: Whereas production cost models are commonly used to simulate an entire calendar year (or multiple years) of operations, RESOLVE simulates the operations of the modeled system for 30 sampled days. Load, wind, and solar profiles for these selected days, sampled from the historical meteorological record over a specified period, are selected and assigned weights so that, taken in aggregate, they produce a reasonable representation of complete distributions of potential conditions . This allows RESOLVE to approximate annual operating costs and dynamics while simulating operations for only the selected days. In this study, a sample of 40 days is used, based on historical meteorological record from 2007 to 2014.

Additional Constraints
RESOLVE layers investment decisions on top of the operational model described above. Each new investment identified in RESOLVE has an impact on how the system operates; the portfolio of investments, as a whole, must satisfy a number of additional conditions.

- Planning reserve margin (PRM): When making investment decisions, RESOLVE requires the portfolio to include enough firm capacity to meet the annual system peak load plus an additional specified amount of PRM requirement. The contribution of each resource type towards this requirement depends on its attributes and varies by type: for instance, variable renewables are discounted more compared to thermal generations because the uncertainties of generation during peak hours. In this study, a PRM requirement of 24% is used for Black Hills.

- Greenhouse gas cap: RESOLVE also allows users to specify and enforce a greenhouse gas constraint on the resource portfolio for a region. As the name suggests, the emission cap type policy requires that annual emissions generated in the entire system be less than or equal to the designed maximum emissions cap. This type of policy is usually implemented by having limited amount of emission allowances within the system. As a result, thermal generators need to purchase allowances for the carbon they produced from the market or from carbon-free generators. In its most extreme form, a greenhouse cap at zero emissions, as illustrated in E3's 100% GHG case in 2050, would preclude all power-sector emissions, though some "zero-emission" fuels such as biofuels or hydrogen still qualify.

PLEXOS Model Description

PLEXOS is a detailed production cost simulation tool used to provide granular operational and cost metrics. For this study, E3 developed an hourly PLEXOS model to evaluate the RESOLVE portfolios for 2022, 2025, and 2030 snapshot years. Each year simulated in the PLEXOS production cost model used real historical load and renewable generation data to allow the RESOLVE portfolios to interact with an actual representation of Black Hills' system. Other model inputs included fuel prices, emissions rates, and specific operational properties for existing and planned generators such as VO&M, minimum up time, minimum down time, ramp rate, and heat rates. Given historical load and operational reserve requirements, PLEXOS optimized Black Hills' generation to meet hourly load while minimizing cost.

Appendix K
Emissions Projections

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

Year	CEP
2022	3.14
2023	2.59
2024	2.03
2025	1.48
2026	1.28
2027	1.09
2028	0.90
2029	0.70
2030	0.51
2031	0.43
2032	0.35
2033	0.27
2034	0.19
2035	0.12
2036	0.11
2037	0.10
2038	0.09
2039	0.09
2040	0.08
2041	0.07
2042	0.07
2043	0.06
2044	0.06
2045	0.05
2046	0.04
2047	0.03
2048	0.02
2049	0.01
2050	0.00

Table K-2
Annual Projected SO_2 Emissions from Generic Resources (Tons)

Year	CEP
2022	0.00
2023	0.00
2024	0.00
2025	0.00
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-3
Annual Projected CO_2 Emissions from Existing Resources (Tons)

Year	CEP
2022	622,357.48
2023	512,441.35
2024	402,525.23
2025	292,609.10
2026	254,190.87
2027	215,772.65
2028	177,354.42
2029	138,936.19
2030	100,508.89
2031	84,997.06
2032	69,476.15
2033	53,955.24
2034	38,434.33
2035	22,913.43
2036	21,508.22
2037	20,103.01
2038	18,697.81
2039	17,292.60
2040	15,887.39
2041	14,679.33
2042	13,471.26
2043	12,263.19
2044	11,055.13
2045	9,847.06
2046	7,877.65
2047	5,908.24
2048	3,938.82
2049	1,969.41
2050	0.00

Table K-4
Annual Projected CO_2 Emissions from Generic Resources (Tons)

Year	CEP
2022	0.00
2023	0.00
2024	0.00
2025	0.00
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-5
Annual Projected NOx Emissions from Existing Resources (Tons)

Year	CEP
2022	39.10
2023	31.21
2024	23.63
2025	16.05
2026	14.04
2027	12.04
2028	10.03
2029	8.02
2030	6.01
2031	5.25
2032	4.48
2033	3.72
2034	2.95
2035	2.19
2036	2.15
2037	2.11
2038	2.07
2039	2.03
2040	1.99
2041	1.94
2042	1.89
2043	1.83
2044	1.78
2045	1.73
2046	1.39
2047	1.04
2048	0.69
2049	0.35
2050	0.00

Table K-6
Annual Projected NOx Emissions from Generic Resources (Tons)

Year	CEP
2022	0.00
2023	0.00
2024	0.00
2025	0.00
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	1.12
2047	2.25
2048	3.37
2049	4.50
2050	5.62

Table K-7
Annual Projected PM Emissions from Existing Resources (Tons)

Year	CEP
2022	30.04
2023	24.93
2024	19.82
2025	14.72
2026	12.79
2027	10.85
2028	8.92
2029	6.99
2030	5.06
2031	4.13
2032	3.20
2033	2.28
2034	1.35
2035	0.43
2036	0.41
2037	0.39
2038	0.37
2039	0.35
2040	0.33
2041	0.31
2042	0.29
2043	0.27
2044	0.25
2045	0.23
2046	0.19
2047	0.14
2048	0.09
2049	0.05
2050	0.00

Table K-8
Annual Projected PM Emissions from Generic Resources (Tons)

Year	CEP
2022	0.00
2023	0.00
2024	0.00
2025	0.00
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-9
Annual Projected Hg Emissions from Existing Resources (Tons)

Year	CEP
2022	0.00
2023	0.00
2024	0.00
2025	0.00
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-10
Annual Projected Hg Emissions from Generic Resources (Tons)

Year	CEP
2022	0.00
2023	0.00
2024	0.00
2025	0.00
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-11
Annual Projected CH_4 Emissions from Existing Resources (Tons)

Year	CEP
2022	11.54
2023	9.51
2024	7.47
2025	5.43
2026	4.72
2027	4.00
2028	3.29
2029	2.58
2030	1.86
2031	1.58
2032	1.29
2033	1.00
2034	0.71
2035	0.43
2036	0.40
2037	0.37
2038	0.35
2039	0.32
2040	0.29
2041	0.27
2042	0.25
2043	0.23
2044	0.21
2045	0.18
2046	0.15
2047	0.11
2048	0.07
2049	0.04
2050	0.00

Table K-12
Annual Projected CH_4 Emissions from Generic Resources (Tons)

Year	CEP
2022	0.00
2023	0.00
2024	0.00
2025	0.00
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-13
Annual Projected N_2O Emissions from Existing Resources (Tons)

Year	CEP
2022	1.15
2023	0.95
2024	0.75
2025	0.54
2026	0.47
2027	0.40
2028	0.33
2029	0.26
2030	0.19
2031	0.16
2032	0.13
2033	0.10
2034	0.07
2035	0.04
2036	0.04
2037	0.04
2038	0.03
2039	0.03
2040	0.03
2041	0.03
2042	0.02
2043	0.02
2044	0.02
2045	0.02
2046	0.01
2047	0.01
2048	0.01
2049	0.00
2050	0.00

Table K-14
Annual Projected N_2O Emissions from Generic Resources (Tons)

Year	CEP
2022	0.00
2023	0.00
2024	0.00
2025	0.00
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-15
Annual Projected CO_2e Emissions from Existing Resources (Tons)

Year	CEP
2022	622,990.13
2023	512,962.27
2024	402,934.40
2025	292,906.54
2026	254,449.26
2027	215,991.98
2028	177,534.70
2029	139,077.42
2030	100,610.16
2031	85,083.46
2032	69,546.77
2033	54,010.09
2034	38,473.40
2035	22,936.72
2036	21,530.08
2037	20,123.45
2038	18,716.81
2039	17,310.18
2040	15,903.54
2041	14,694.25
2042	13,484.95
2043	12,275.66
2044	11,066.37
2045	9,857.07
2046	7,885.66
2047	5,914.24
2048	3,942.83
2049	1,971.41
2050	0.00

Table K-16
Annual Projected CO_2e Emissions from Generic Resources (Tons)

Year	CEP
2022	0.00
2023	0.00
2024	0.00
2025	0.00
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

Appendix L
Air Pollution Control Division Verification Workbooks

See separately filed appendices.

Appendix L - Base ERP_Clean Energy Plan Verification Workbook
Appendix L - Base ERP_no SCC with TC_Clean Energy Plan Verification Workbook
Appendix L - Base ERP_no SCC_Clean Energy Plan Verification Workbook
Appendix L - Base ERP_with TC_Clean Energy Plan Verification Workbook
Appendix L - C&I Generation CEP_Clean Energy Plan Verification Workbook
Appendix L - C&I Generation CEP_no SCC with TC_Clean Energy Plan Verification Workbook
Appendix L - C&I Generation CEP_no SCC_Clean Energy Plan Verification Workbook
Appendix L - C&I Generation CEP_OWM with TC_Clean Energy Plan Verification Workbook
Appendix L - C&I Generation CEP_OWM_Clean Energy Plan Verification Workbook
Appendix L - C&I Generation CEP_with TC_Clean Energy Plan Verification Workbook
***Appendix L - CEP_Clean Energy Plan Verification Workbook**
Appendix L - CEP_Increased Elec with TC_Clean Energy Plan Verification Workbook
Appendix L - CEP_Increased Elec_Clean Energy Plan Verification Workbook
Appendix L - CEP_no SCC with TC_Clean Energy Plan Verification Workbook
Appendix L - CEP_no SCC_Clean Energy Plan Verification Workbook
Appendix L - CEP_with TC_Clean Energy Plan Verification Workbook
Appendix L - High Gas_Clean Energy Plan Verification Workbook
Appendix L - High Load_Clean Energy Plan Verification Workbook
Appendix L - Low Gas_Clean Energy Plan Verification Workbook
Appendix L - Low Hydrogen_Clean Energy Plan Verification Workbook
Appendix L - Low Load_Clean Energy Plan Verification Workbook
Appendix L - No New Renewables_Clean Energy Plan Verification Workbook
Appendix L - No New Renewables_with TC_Clean Energy Plan Verification Workbook

***2030 Ready Preferred Portfolio**

Appendix M
Price Forecasts

See separate appendix.

Schedule M-1	Market Clearing Price Forecast – CO East & AZ-PV Markets – Base Case
Schedule M-2	Seasonal Firm Market Price Forecast – AZ-PV Market – Base Case
Schedule M-3	Natural Gas Price Forecast – NG Colorado Market – Base Case
Schedule M-4	Oil Price Forecast – No. 2 Distillate – Base Case
Schedule M-5	Market Clearing Price Forecast – CO East & AZ-PV Markets – High Gas Case
Schedule M-6	Seasonal Firm Market Price Forecast – AZ-PV Market – High Gas Case
Schedule M-7	Natural Gas Price Forecast – NG Colorado Market – High Gas Case
Schedule M-8	Market Clearing Price Forecast – CO East & AZ-PV Markets – Low Gas Case
Schedule M-9	Seasonal Firm Market Price Forecast – AZ-PV Market – Low Gas Case
Schedule M-10	Natural Gas Price Forecast – NG Colorado Market – Low Gas Case

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

See separate appendix.

Appendix N includes the following Model Energy Purchase Agreements

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 for Fossil Fuels

Abbreviations

ALJ – Administrative Law Judge
AQCC – Air Quality Control Commission
ATB – NREL 2020 Annual Technology Baseline
aLOLP - Annual Loss of Load Probability
BACT – Best Available Control Technology
Black Hills - Black Hills Colorado Electric, LLC
Btu – British Thermal Unit
BTM – Behind-the-meter
C&I – Commercial and Industrial
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
CEPR – Clean Energy Plan Rider
CIS+ - Customer Information System
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
CPP – EPA Clean Power Plan
C.R.S. – Colorado Revised Statutes
CSG- Community Solar Garden
CT – Combustion Turbine
DG – Distributed Generation
Division – Colorado Air Pollution Control Division
DSM – Demand-Side Management
E3 – Energy & Environmental Economics
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
FIP – Federal Implementation Plans

GHG – Greenhouse Gas
GRP - Gross Regional Product
GWh – Gigawatt hour
HAPG – Hitachi ABB Power Grids
HDD – Heating Degree Days
HDH – Heating Degree Hours
IPP – Independent Power Producer
ITC – Investment Tax Credit
IWG – Interagency Working Group
JDA – Joint Dispatch Agreement
kV – Kilovolt
kW – Kilowatt
kWh – Kilowatt-hour
LOLE – Loss of Load Expectation
LOLH – Loss of Load Hours
LOLP – Loss of Load Probability
LTP - Local Transmission Plan
MATS - EPA's Mercury and Air Toxics Standard
MPS – Missouri Public Service
MVS – Modeling and Validation Subcommittee
MW – Megawatt
MWh – Megawatt hour
NCDC - NOAA National Climatic Data Center
NERC – North American Electric Reliability Corporation
NWPP-C – NWPP Central (subregion of WECC)
OLS – Ordinary Least Squares
Open RFP – competitive solicitation
Order 1000 – FERC Order No. 1000
OWM – Organized Wholesale Market
PAGS – Pueblo Airport Generating Station
PCC – Planning Coordination Committee
PPA – Purchase Power Agreement
PSD – Prevention of Significant Deterioration
PSCo – Public Service Company of Colorado
PV solar– Photovoltaics
PVRR – Present Value of Revenue Requirements
QRU – Qualifying Retail Utility
RAC – Reliability Assessment Committee
RAP – Resource Acquisition Period
REC – Renewable Energy Credit
RES – Renewable Energy Standard
RES Plan – Black Hills Colorado Electric Renewable Energy Standard Plan
RESA – Renewable Energy Standards Account
RFP – Request for Proposals
Roadmap – January 2021 Colorado Greenhouse Gas Pollution Reduction Roadmap

SB – Senate Bill
SB 07-100 – Colorado Senate Bill 07-100, codified at § 40-2-126(2), C.R.S.
SB 19-236 - Senate Bill 19-236, codified in § 40-2-125.5, C.R.S.
SCC – Social Cost of Carbon
SCM – Social Cost of Methane
SPG- Sub-Regional Planning Group
SPP – Southwest Power Pool
SSPG – Sierra Subregional Planning Group
Sts – The Studies Subcommittee
SWAT – Southwest Area Transmission Group
TC Colorado – TC Colorado Solar, LLC
TCPC - Transmission Coordination and Planning Committee
TSD – Technical Support Document
The RES Rules - Commission Rules 4 CCR 723-3-3650 *et seq.*
The RES Statute – C.R.S., § 40-2-124 *et seq.*
TSD – Technical Support Document
UPC – Use per Customer
VER – Variable Energy Resources
W&P – Woods & Poole Economics, Inc.
WACC – Weighted-Average Cost of Capital
WAPA - Western Area Power Administration
WECC – Western Electricity Coordinating Council
WEIS – Western Energy Imbalance Service
WMEG – Western Markets Exploratory Group