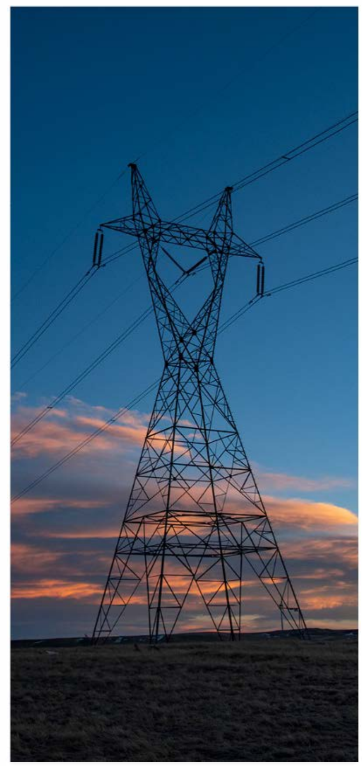
Cheyenne Light, Fuel and Power Company and Black Hills Power, Inc.

2021 Integrated Resource Plan



Black Hills Energy
Ready

Legal Naming Conventions

Cheyenne Light, Fuel and Power Company (d/b/a Black Hills Energy, a direct, wholly-owned subsidiary of Black Hills Corporation) provides electric service to customers in the Cheyenne, Wyoming area; the company is referred to as 'Cheyenne Light' throughout this IRP.

Black Hills Power, Inc. (d/b/a Black Hills Energy, a direct, wholly-owned subsidiary of Black Hills Corporation) provides electric service to customers in western South Dakota, northern Wyoming and southeast Montana; the company is referred to as 'Black Hills Power' throughout this IRP.

TABLE OF CONTENTS

FIGURES

TABLES

01. EXECUTIVE SUMMARY:

PRELIMINARY STATEMENT:

The Integrated Resource Plan (IRP) process and evaluation for Cheyenne Light Fuel and Power Company (Cheyenne Light) and Black Hills Power, Inc. (Black Hills Power) supports that forecasted future needs of both utilities will be best met through a balanced mix of generation resources, including coal, natural gas, solar, and wind. In addition, the preferred plan for each utility includes the continued investigation of adding battery storage to further diversify resource portfolios. Unlike prior IRPs submitted by the utilities, this IRP includes an analysis of the resource needs of Cheyenne Light individually, Black Hills Power individually, and a joint analysis of a combined load for the two utilities.

The goal of the IRP is to develop a preferred plan minimizing cost to customers, while mitigating customer risk, achieving generation and transmission adequacy, continuing the safe delivery of reliable energy, and meeting both environmental objectives and regulatory requirements.

For Cheyenne Light, the IRP identified a near-term capacity shortfall of 10 MW beginning in 2021, driven by native load growth on the system. The IRP also identifies the benefits of exploring an investment in an expansion of Cheyenne Light owned transmission to lower costs associated with the Western Area Power Administration Loveland Area Project (WAPA-LAP) transmission system.

Based on forecasts and analysis, Cheyenne Light recommends seasonal firm market purchases in the near-term need planning period as the preferred, least cost alternative to meet the identified capacity shortfall. In addition, Cheyenne Light recommends the evaluation of a utility owned transmission expansion within the near-term need planning period as the least cost alternative to current WAPA-LAP transmission expenses.

For Black Hills Power, the IRP identified a near-term capacity shortfall of 40 MW beginning in 2021, driven by native load growth on the system and the end of design life of the Neil Simpson Unit II coal-fired steam power plant in 2025. Based on forecasts and analysis, Black Hills Power recommends the addition of renewable energy resources with a nameplate capacity of up to 100 MW in the near-term need planning period and the conversion of Neil Simpson Unit II as the preferred, least cost alternative to meet the identified resource need. The credited capacity of renewable resources at this level will address the capacity shortfall while providing low cost energy compared to other alternatives.

Because the timing of recommended resource additions for Cheyenne Light and Black Hills Power are not well-aligned, Cheyenne Light and Black Hills Power do not recommend a joint preferred plan, but instead recommend the previously discussed individual preferred plans to meet the identified capacity shortfalls in the IRP. The joint analysis is a productive addition to the IRP process, however, and the utilities recommend that this process be continued in the future as it may provide opportunities to the extent resource needs become better aligned.

INTRODUCTION:

The 2021 IRP provides a road map for defining the appropriate energy and capacity additions required to serve customers reliably and economically. The IRP is based on a planning period of 2021 through 2040 and a near-term need planning period of 2021 – 2026.

This IRP is being filed pursuant to a proposal by the utilities incorporated into a Wyoming Public Service Commission (Wyoming Commission) order in the Renewable Ready docket.[1] In response to requests and/or inquiries by the Wyoming Office of Consumer Advocate (OCA) and the Wyoming Commission, the utilities agreed to file an IRP no later than July 1, 2021 that included an analysis for Cheyenne Light individually, Black Hills Power individually, and a joint analysis for the two utilities.[2] In addition, the utilities agreed to conduct input meetings with Wyoming Commission Staff and the OCA prior to filing in order to develop a more robust IRP process and report. Cheyenne Light and Black Hills Power met with the Wyoming Commission Staff and the OCA on October 8, 2020 and March 8, 2021. In addition, Cheyenne Light and Black Hills Power presented the IRP generally at a publicly noticed Wyoming Commission meeting on June 10, 2021.

[1] Docket No. 20003-177-ET-18 (Record No. 15170), Memorandum Opinion, Findings and Order Approving Application, Issued October 15, 2019, Paragraph 85.

2 Id.

The IRP utilizes industry standard methods to determine the capacity necessary to fulfill forecasted future load growth; and determine the cost of resources that will sufficiently serve the forecasted load.

Capacity and energy resource needs were identified through load forecasts for both Cheyenne Light and Black Hills Power. The IRP then analyzed the existing resources with the load forecasts to identify and develop resource portfolios to meet the forecasted capacity and energy requirements. A cost and risk analysis was conducted on each of the identified resource portfolios in order to identify a preferred resource plan for each utility.

Figure 01-1 illustrates the IRP process:

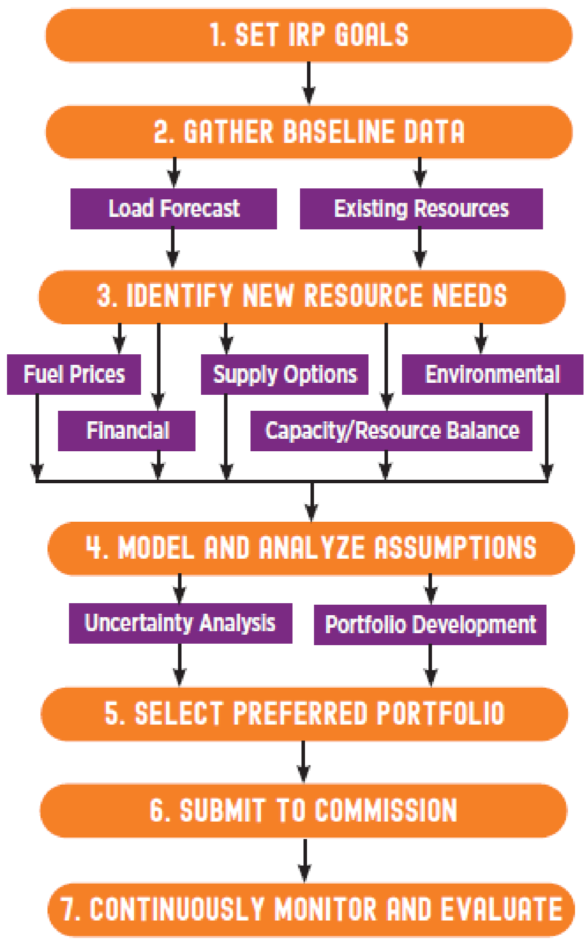


Figure 01-1. IRP Process Flowchart

LOAD FORECAST:

The IRP employs an econometric forecasting methodology to forecast retail peak demand and energy from different types of data: historical load, revenue, economics, and weather data. These datasets were used to develop monthly system-level peak demand forecast and the major customer class energy forecasts. The IRP developed base, low, high, and high-high load forecasts, and includes system-level demand and major customer class energy forecasts using historical data. Detailed information related to the load forecasts is found in Chapter 7 of the IRP.

Cheyenne Light's load forecast excluded all Large Power Contract Service (LPCS) loads as well as any blockchain interruptible service loads (BCIS) as these specialized tariffs do not require inclusion in the IRP due to the nature of the service provided.[3]

According to the results of the load forecast analysis, Cheyenne Light and Black Hills Power do not have sufficient capacity to serve future customer demand. As illustrated in Figure 01-2, a gap exists between existing resources and the Cheyenne Light peak demand plus a 15 percent reserve planning margin during the planning period. This gap indicates capacity and energy must be obtained through either market purchases or additional resources:

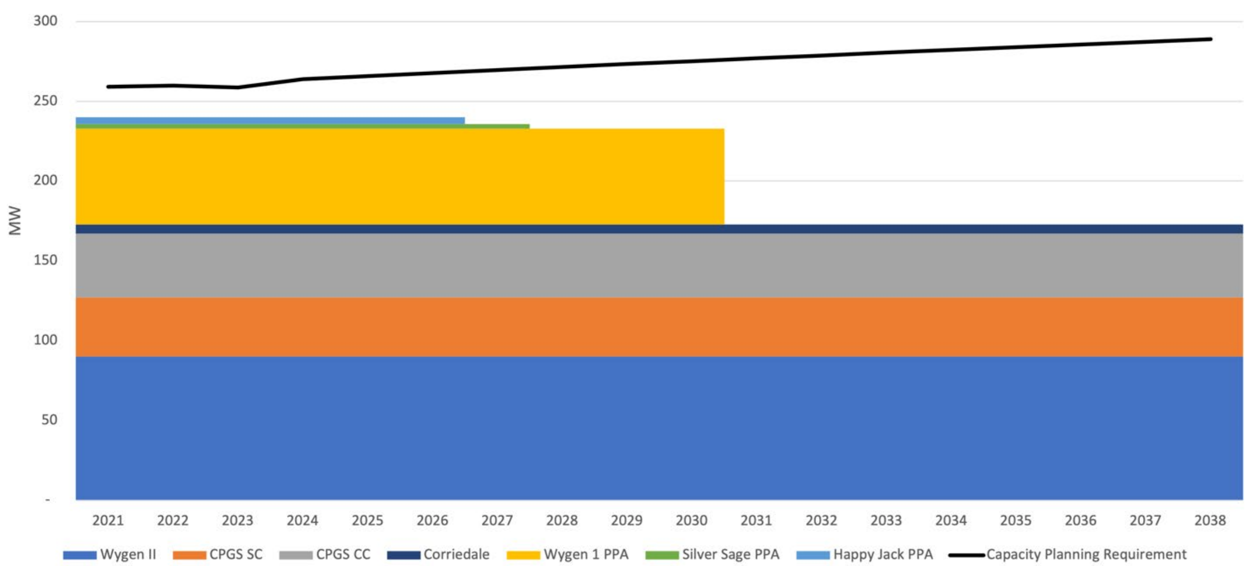


Figure 01-2. Cheyenne Light Existing Resources Plus Reserve Margin (2021 – 2040)

As illustrated in Figure 01-3, a gap exists between existing resources and the Black Hills Power peak demand plus a 15 percent reserve planning margin during the planning period. This gap

3 Black Hills Power does not have an LPCS tariff, BCIS tariff, or any similarly situated tariff.

indicates capacity and energy must be obtained through either market purchases or additional resources:

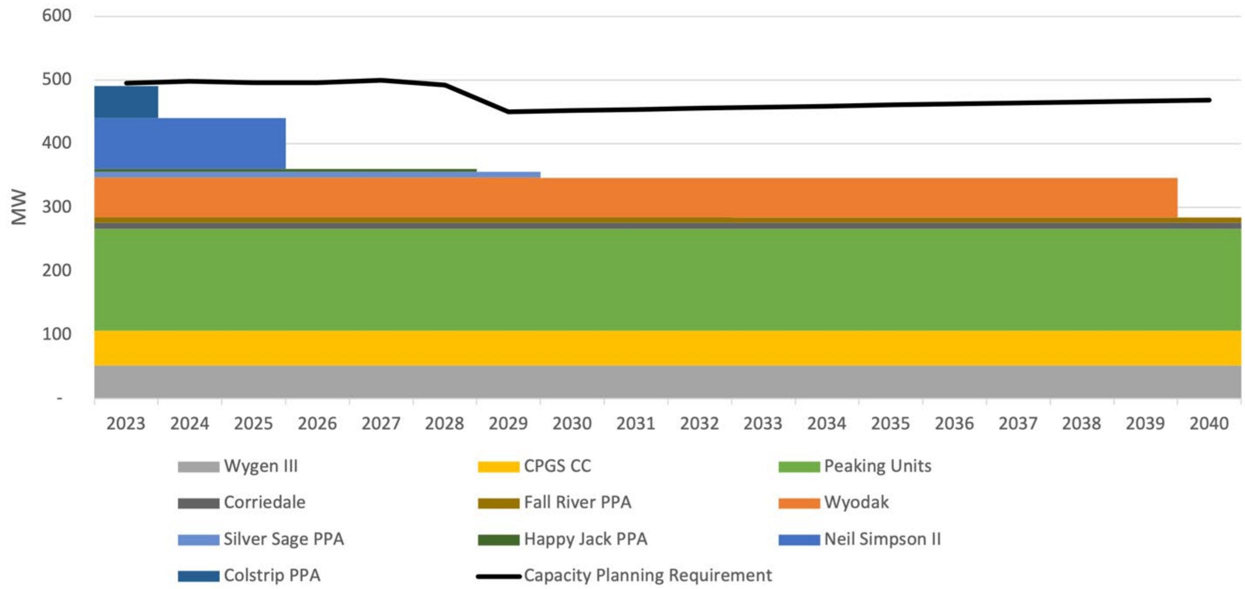


Figure 01-3. Black Hills Power Existing Resources Plus Reserve Margin (2021 – 2040)

PORTFOLIO EVALUATION:

Cheyenne Light and Black Hills Power performed modeling using an array of conventional and renewable generation resources to develop various resource portfolios that could meet the resource needs of the utilities through the planning period. The scenarios developed for this analysis included variables that would create the largest impact on cost variability and risk to result in unique resource portfolios.

A brief description of the nine scenarios follows:

Base Plan. Included all existing resources as available and addressed (a) base peak demand and annual energy forecasts, (b) base natural gas, coal, and economy energy forecasts, (c) seasonal firm market purchases up to 50 MW per utility and up to 100 MW for the joint portfolios, and (d) conventional and renewable energy resource options.

- Developed candidate resource portfolios: B1, C1, J1.

Environmental Scenario. Investigated the impact a CO2 tax would have on the resource portfolio.

- Developed candidate resource portfolios: B2, C2, J2.

Low Gas Scenario. Investigated the impact extended low natural gas prices would have on the resource portfolio.

- Developed candidate resource portfolios: B3, C3, J3.

High Gas Scenario. Investigated the impact high natural gas prices would have on the resource portfolio.

- Developed candidate resource portfolios: B4, C4, J4.

Low Load Scenario. Investigated the impact lower than forecasted load growth would have on the resource portfolio.

- Developed candidate resource portfolios: B5, C5, J5.

High Load Scenario. Investigated the impact higher than forecasted load growth would have on to the resource portfolio.

- Developed candidate resource portfolios: B6, C6, J6.

High-High Load Scenario. Investigated the impact higher than forecasted load growth, with an additional 25 MW step load starting in 2024, would have on the resource portfolio.

- Developed candidate resource portfolios: B7, C7.

Base Battery Energy Storage System Scenario. Investigated the impact adding BESS in 2023 would have on the resource portfolio.

- Developed candidate resource portfolios: B8, C8.

Carbon Capture Scenario for Cheyenne Light. Investigated the impact adding carbon capture to Wygen II would have on Cheyenne Light's resource portfolio. This scenario was investigated because House Bill 200 requires the Wyoming Commission to establish energy portfolio standards requiring a specified percentage of electricity to be dispatchable, reliable, and low carbon by 2030.

- Developed candidate resource portfolio: C9.

The nine scenarios resulted in nine candidate resource portfolios for Cheyenne Light, eight candidate resource portfolios for Black Hills Power, and six joint resource portfolios. The six scenarios analyzed for both utilities and the joint plan (C1-C6, B1-B6, and J1-J6) investigate the impacts of the most sensitive modeling inputs. Two additional Cheyenne Light and Black Hills Power scenarios (C7-C8 and B7-B8) investigate utility specific impacts of adding a new large customer and battery storage. The ninth Cheyenne Light scenario (C9) was developed to investigate carbon capture. The candidate resource portfolios are discussed in detail in Chapter 8.

The resulting candidate resource portfolios for Cheyenne Light, not including seasonal firm market purchases, are illustrated in Table 01-1:

Cheyenne Light Resource Portfolios—Scenario Analysis									
Year	Base Plan (C1)	Environmental Scenario (C2)	Low Gas Scenario (C3)	High Gas Scenario (C4)	Low Load Scenario (C5)	High Load Scenario (C6)	High-High Load Scenario (C7)	Base BESS Scenario (C8)	Carbon Capture Scenario (C9)
2021									
2022									
2023		Wind 50 MW						BESS 10 MW	
2024		Solar 50 MW					Wind 50 MW		
2025									Solar 50 MW Wygen 2 CCUS
2026						Wind 50 MW	BESS 10 MW Wind 50 MW		Wind 50 MW
2027									
2028									
2029		Wind 50 MW							
2030									
2031									
2032				Wind 50 MW			Wind 50 MW		
2033	CT 40 MW Wind 100 MW	CT 40 MW	CT 90 MW	CT 40 MW Wind 100 MW	CT 40 MW Wind 50 MW	CT 90 MW Wind 50 MW	CT 90 MW	CT 40 MW Wind 100 MW	CT 90 MW Wind 50 MW
2034									
2035									
2036									
2037									
2038					Wind 50 MW	Solar 50 MW			
2039							Wind 50 MW		
2040									

Table 01-1. Cheyenne Light Resource Portfolios – Scenario Analysis

The resulting candidate resource portfolios for Black Hills Power, not including seasonal firm market purchases, are illustrated in Table 01-2:

Black Hills Power Resource Portfolios—Scenario Analysis								
Year	Base Plan (B1)	Environmental Scenario (B2)	Low Gas Scenario (B3)	High Gas Scenario (B4)	Low Load Scenario (B5)	High Load Scenario (B6)	High-High Load Scenario (B7)	Base BESS Scenario (B8)
2021								
2022								
2023	Wind 50 MW	Wind 250 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	BESS 10 MW Solar 50 MW
2024	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Solar 50 MW	Wind 50 MW	Wind 150 MW Solar 50 MW	Wind 50 MW
2025	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW Solar 100 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW Solar 100 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW
2026								
2027								
2028								
2029								
2030					Wind 50 MW			
2031								
2032								Wind 50 MW
2033								
2034								
2035								
2036								
2037								
2038	Wind 50 MW					Wind 50 MW		
2039		Wind 100 MW						Wind 50 MW
2040	Wind 100 MW		Wind 150 MW	Wind 150 MW	Wind 100 MW	Wind 150 MW	Wind 150 MW BESS 10 MW	Wind 100 MW

Table 01-2. Black Hills Power Resource Portfolios – Scenario Analysis

The resulting candidate resource portfolios for the joint analysis, not including seasonal firm market purchases, are illustrated in Table 01-3:

Joint Resource Portfolios— Scenario Analysis						
Year	Base Plan (J1)	Environmental Scenario (J2)	Low Gas Scenario (J3)	High Gas Scenario (J4)	Low Load Scenario (J5)	High Load Scenario (J6)
2021						
2022						
2023		Wind 200 MW Solar 200 MW				
2024						
2025	NSII Coal to Gas 80 MW Solar 200 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW Solar 200 MW	NSII Coal to Gas 80 MW Solar 200 MW	NSII Coal to Gas 80 MW Solar 200 MW
2026				Wind 50 MW		
2027						
2028						
2029						
2030						
2031						Wind 50 MW
2032						Wind 50 MW
2033	Wind 100 MW			Wind 150 MW	Wind 100 MW	Wind 50 MW
2034	Wind 50 MW					Wind 50 MW
2035						
2036			Wind 50 MW			
2037					Wind 50 MW	
2038				Wind 50 MW		Wind 50 MW
2039						
2040	Wind 150 MW	BESS 10 MW	Wind 150 MW	Wind 100 MW	Wind 50 MW	Wind 150 MW

Table 01-3. Joint Resource Portfolios – Scenario Analysis

Production cost modeling was performed on the candidate resource portfolios to calculate the deterministic present value revenue requirement (PVRR), an important factor in the identification of a preferred resource plan. See Chapter 8 – Portfolio Analysis and Selection – for more detail.

Figure 01-4 illustrates the PVRR for the Cheyenne Light candidate resource portfolios:

Figure 01-4. Present Value Revenue Requirements for Cheyenne Light Resource Portfolios

Figure 01-5 illustrates the PVRR for the Black Hills Power candidate resource portfolios:

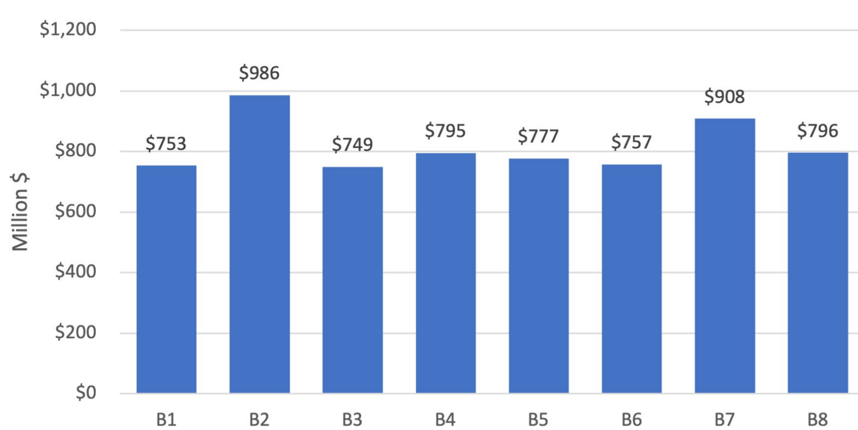


Figure 01-5. Present Value Revenue Requirements for Black Hills Power Resource Portfolios

Figure 01-6 illustrates the PVRR for the joint candidate resource portfolios:

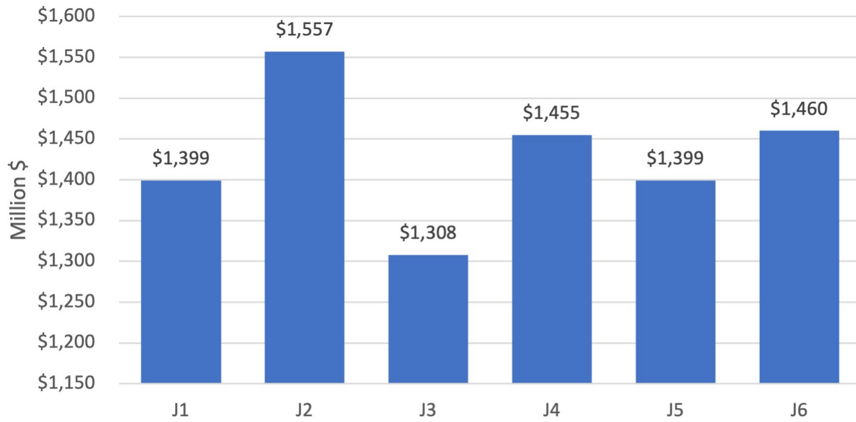


Figure 01-6. Present Value Revenue Requirements for Joint Resource Portfolios

Assumptions utilized in the IRP and its analysis are contained in Chapter 7 – Modeling Approach and Assumptions.

PREFERRED PLAN:

For Cheyenne Light, the results of the preferred plan modeling and analysis, portfolio C8, do not identify the addition of resources. Instead, the near-term resource needs to meet the peak demands of the Cheyenne Light system plus the 15 percent reserve margin, can be met through seasonal firm market purchases. The IRP also identified a potential for a Cheyenne Light investment in the expansion of its owned transmission system. Cheyenne Light's load growth is outpacing other customer loads on the WAPA-LAP system and the WAPA-LAP annual revenue requirement is growing steadily – leading to increased costs to Cheyenne Light customers. Cheyenne Light is engaging in a detailed analysis and evaluation of the customer and system benefits that would be gained through a utility owned expansion of the transmission system beginning in the near-term need planning period. Finally, the Cheyenne Light preferred plan includes the continued investigation of the customer value proposition of adding battery storage.

For Black Hills Power, the results of the modeling and analysis identify portfolio B8 – the Base Battery Storage Portfolio – as the preferred resource plan to meet near-term resource needs. This portfolio recommends the addition of battery storage of 10 MW and Solar of 50 MW in 2023, the addition of 50 MW of wind in 2024, and the conversion of Neil Simpson Unit II to gas in 2025. Although the B8 portfolio designates the specific type of renewable (solar v. wind), Black Hills Power will evaluate all types of renewable resources to meet the identified near-term need planning period in order to ensure the least cost, least risk resource is implemented.

Because the timing of recommended resource additions for Cheyenne Light and Black Hills Power are not well-aligned, Cheyenne Light and Black Hills Power do not recommend a joint preferred plan, but instead recommend the individual preferred plans to meet the identified capacity shortfalls indicated in the IRP.

CONCLUSION:

The long-term resource supply needs of Cheyenne Light and Black Hills Power are best met through a balanced mix of generation resources including coal, natural gas, solar, wind, and battery storage. Cheyenne Light's near-term planning period need is best met with seasonal firm market purchases. Black Hills Power's near-term planning period need is best met with the addition of renewable resources prior to the conversion of Neil Simpson Unit II from coal to natural gas in 2025. The recommended preferred plans of Cheyenne Light and Black Hills Power represent the least cost, least risk solution for customers in response to the identified capacity shortfalls.

02. ABOUT BLACK HILLS ENERGY

Black Hills Corporation is a customer-focused utility holding company that conducts electric operations through three subsidiary utilities: Cheyenne Light, Fuel and Power Company; Black Hills Power; and Black Hills Colorado Electric. These utilities—each doing business as Black Hills Energy—deliver electricity to customers in Wyoming, South Dakota, Montana, and Colorado. The 2021 IRP addresses the future needs of Cheyenne Light and Black Hills Power.

Black Hills Corporation is collectively fueled by its vision, mission, and values.

Vision: Be the Energy Partner of Choice. We strive to be the energy partner of choice. Whether our customers are served by our regulated or non-regulated businesses, we want them to value our service and business relationship.

Mission: Improving Life with Energy. Every day, we want to improve life with energy. We produce, market, and deliver the vital electricity, coal, and natural gas our customers need. Through our efforts, products, and services, we share our personal energy to strengthen our communities and support growth and development.

Values. We are proud of our employees; they represent what we stand for. There are several key values that have been fundamental to our success for the past 137 years, and there are others that will be vital to our future success. These are the values we feel align us to our vision and that our employees demonstrate every day.

These values (Figure 02-1) align us to our vision, mission, and values.

Agility
We embrace change and challenge ourselves to adapt quickly to opportunities.

Customer Service
We are committed to providing a superior customer experience every day.

Partnership
Our partnerships with shareholders, communities, regulators, customers and each other make us all stronger.

Communication
Consistent, open and timely communication keeps us focused on our strategy and goals.

Integrity
We hold ourselves to the highest standards based on a foundation of unquestionable ethics.

Respect
We respect each other. Our unique talents and diversity anchor a culture of success.

Creating Value
We are committed to creating exceptional value for our shareholders, employees, customers and the communities we serve...always.

Leadership
Leadership is an attitude. Everyone must demonstrate the care and initiative to do things right.

Safety
We commit to live and work safely every day.

Figure 02-1. Black Hills Energy Values

A Social Perspective

Black Hills Corporation is committed to improving the quality of life in its communities. The company keeps people at the center of its decision making.

Social Responsibility. Social responsibility plays a vital role in fulfilling the company's vision and mission.

Company employees donate tens of thousands of hours in service to their communities each year. Whether it's organizing a blood drive, coaching a youth sports team, raising funds to find a cure for cancer, or leading a nonprofit board, employees help when they are called upon, wherever they live.

The company's commitment extends to its financial resources as well. Not only are its employees leading donors to local United Way campaigns, but as a company, Black Hills Corporation donates hundreds of thousands of dollars to worthwhile philanthropic causes and organizations every year. In 2020, the company's charitable giving totaled over $1.6 million in South Dakota and $508,000 in Wyoming. Support for local economic development initiatives totaled $547,000 in South Dakota and $135,000 in Wyoming.

More than 1,700 South Dakota customers and 7,200 Wyoming customers participated in energy efficiency programs and benefited from energy savings, with customer rebates in 2020 totaling approximately $650,000. Finally, the energy assistance program operated by both utilities, Black Hills Cares, assisted almost 600 families in need with $400,000 in financial donations.

Inclusion, Diversity, and Belonging. Unique talents and diversity anchor a culture of success and diverse teams and cultures deliver customer and shareholder value. The company proactively and intentionally fosters an environment that respects all people without regard to race, color, religion, sex, sexual orientation, gender identity, national origin, ancestry, creed, disability, age, veteran status, or any other class of people.

Employee resource groups encourage inclusion and belonging, with specific programs for women, veterans, racially and ethnically diverse employees, and new employees.

Supplier Diversity. Cheyenne Light and Black Hills Power are committed to supporting small and diverse local businesses in local communities. The Supplier Diversity Program encourages local, small, women-owned, veteran-owned and minority-owned businesses to provide competitive bids for needed materials and services.

Workplace Safety. Safety is a top priority for the company. Over the past 12 years, the company has reduced workplace injuries by more than 73 percent and continues to see long-term, sustained improvements in its safety practices and performance. In 2020, Black Hills Corporation experienced 1.0 Occupational Safety and Health Administration (OSHA) incidents per 200,000 work hours, well below the utility industry average of 2.2. In that same year, the Preventable Motor Vehicle Incident Rate (vehicle accidents per 1 million miles driven) was 2.38, also well below the industry average of 3.33.

CUSTOMERS AND SERVICE TERRITORIES

Cheyenne Light and Black Hills Power serve a total of 117,462 customers over a three-state service territory: Wyoming, South Dakota, and Montana. The utilities provide energy to two large cities—Rapid City, South Dakota and Cheyenne, Wyoming—in addition to approximately 45 mostly rural communities.

Table 02-1 shows year end customer counts by utility for the years 2016 - 2020. Year over year growth rates are approximately 1 percent.

Utility	2016	2017	2018	2019	2020
Black Hills Power	71,353	72,184	72,533	73,052	73,700
Cheyenne Light	41,531	42,130	42,694	43,318	43,762
Total	112,884	114,314	115,227	116,370	117,462

Table 02-1. Cheyenne Light and Black Hills Power Customer Count Trends

Figure 02-2 illustrates the total number of commercial, industrial, and residential customers served in the Cheyenne Light and Black Hills Power service territories.

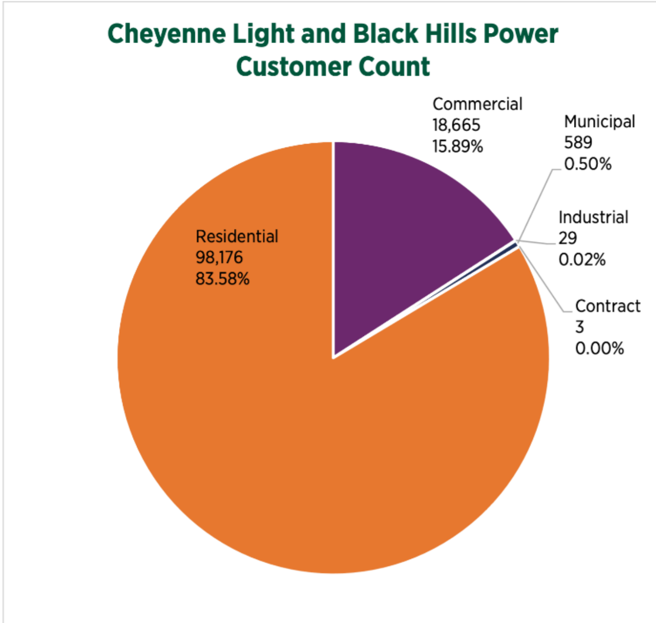


Figure 02-2. Cheyenne Light and Black Hills Power Customer Count

Figure 02-3 illustrates the amount of energy sold by Cheyenne Light and Black Hills Power to each segment and on the wholesale market.

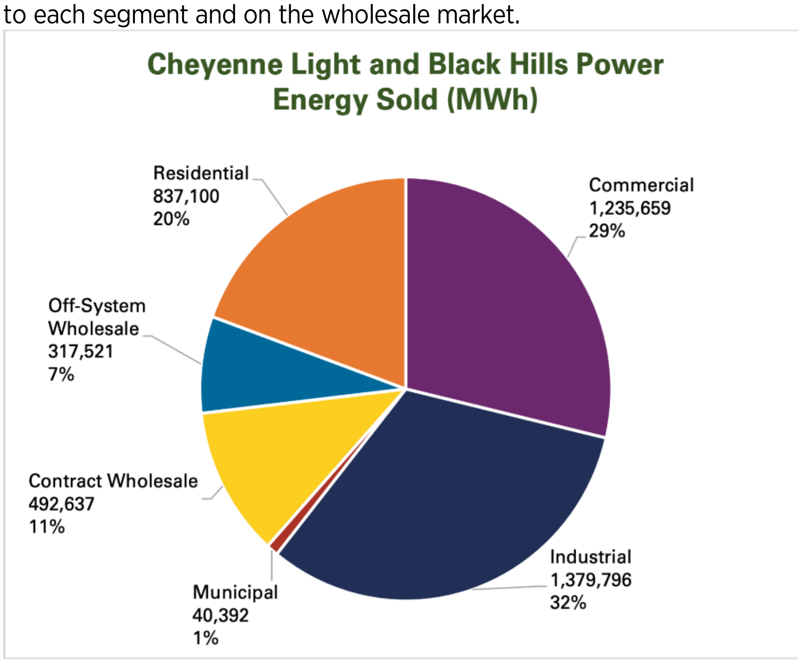


Figure 02-3. Cheyenne Light and Black Hills Power Energy Sold by Segment

Cheyenne Light Service Territory

Cheyenne Light provides energy to almost 44,000 residential, commercial, industrial, and municipal customers in southeast Wyoming, including five data center customers. The utility has more than 70 employees, maintains 58 miles of transmission lines and 1,320 miles of distribution lines, and serves the city of Cheyenne and most of rural Laramie County.

Three of Cheyenne Light's generating stations are in the Cheyenne Light service territory: Cheyenne Prairie single-cycle combustion turbine (CT), Cheyenne Prairie combined-cycle CT, and the Corriedale Wind Facility. The Wygen II power plant is in the Gillette Energy Complex. The utility also holds power purchase agreements (PPA) with the Wygen I power plant and two wind facilities: Happy Jack and Silver Sage.

Black Hills Power Service Territory

Black Hills Power provides energy to almost 74,000 residential, commercial, industrial, and municipal customers in southwest South Dakota, northeast Wyoming, and a small area of southeast Montana. The utility has more than 222 employees, maintains 1,286 miles of transmission lines and 2,565 miles of distribution lines, and serves 43 communities in the three-state service territory.

Nine of Black Hills Power's generating stations are in their service area.

Four generating stations owned wholly or partially by Black Hills Power are in the Gillette Energy Complex: Wygen III, Neil Simpson Unit II, and Wyodak generators and the Neil Simpson single-cycle CT. Three plants are in Rapid City: Lange simple-cycle CTs, Ben French diesels, and Ben French simple-cycle CTs. Black Hills Power also holds PPAs with Colstrip generating station, two wind facilities—Happy Jack, and Silver Sage, and one pending photovoltaic array with Fall River solar.

READY TO SERVE

Reliability

Over the past 10 years, generation reliability for Cheyenne Light and Black Hills Power units was in the top quartile for investor-owned utilities in the country. For each of the last five years, the Edison Electric Institute (EEI) and the Institute of Electrical and Electronics Engineers (IEEE) has ranked both Cheyenne Light and Black Hills Power in the top quartile for system reliability. The reliability of the Cheyenne Light and Black Hills Power systems was tested in February 2021 by winter storm Uri. Despite record-breaking cold temperatures across much of the country, Cheyenne Light and Black Hills Power were able to maintain service to customers without curtailment or significant outages throughout the weather event.

Reducing Greenhouse Gas Emission Intensity

In November 2020, Black Hills Corporation announced clean energy goals to reduce greenhouse gas (GHG) emission intensity for its electric utilities 40 percent by 2030 and 70 percent by 2040.[4] The goals are based on prudent and proven solutions to reduce emission intensity while minimizing cost impacts to customers.

Cleaner Energy through the Renewable Ready Program

In response to customer interest in renewable energy to meet sustainability goals, the company created the Renewable Ready program for Cheyenne Light and Black Hills Power customers. Renewable Ready provides large volume commercial customers, industrial customers, and governmental agencies the option of fulfilling up to 100 percent of their electricity needs from the utility owned (Cheyenne Light 38%, Black Hills Power 62%) 52.5 MW Corriedale Wind Energy Facility. Corriedale went online in November of 2020 and the Renewable Ready program is fully subscribed with subscription periods ranging from five years to 25 years.

CONCLUSION

For 137 years, Black Hills Corporation has been committed to delivering safe, reliable, and cost-effective energy to customers. The company's current plans and strategies build upon that history by ensuring a resilient power supply, keeping energy cost-effective for customers, a cleaner energy future, transforming the customer experience, responsibly serving a growing customer base, pursuing operating efficiencies, and modernizing the utility infrastructure. The 2021 IRP is a key component of the company's ongoing commitment to cost-effectively plan and execute to meet the needs of customers.

[4] Black Hills Corporation clean energy goals were developed by considering current existing technology and are based on 2005 emission intensity levels.

03. INTEGRATED RESOURCE PLANNING ENVIRONMENT

The environment in which Cheyenne Light and Black Hills Power must plan for future resources continues to evolve. There are uncertainties beyond the control of the utilities during the IRP planning cycle.

FEDERAL POLICIES AND ECONOMIC CONDITIONS

Federal policies affecting energy generation are constantly in flux, especially those regarding plant emissions. As such, Cheyenne Light and Black Hills Power continuously monitor orders, regulations, and legislation to assess their impact on the current and planned generation mix and operations. Whenever possible, the utilities assess and comment on pending rules and requirements and participate in hearings to impart their perspective.

Economic conditions are important factors that impact the supply and demand of electricity. As economic activity increases, electric demand increases which can impact prices. According to the U.S. Bureau of Labor Statistics, the national unemployment rate decreased by 0.4 percentage points to 6.3 percent in January 2021. By March, the national rate decreased further to 6.0 percent. Unemployment rates varied across the country from a high of 9.0 percent in Hawaii and a low of 2.9 percent in Nebraska, Utah, Vermont, and South Dakota.[5]

In March 2021, the median price for all types of existing home sales rose by an annual rate of 17.2 percent, reaching a historic high of $329,100. The median price for existing single-family

5 https://www.bls.gov/opub/ted/2021/unemployment-rates-up-in-40-states-and-d-c-from-march-2020-to-march-2021.htm

home sales rose by 18.4 percent to $334,500, both historic highs. All regions of the country posted similar double-digit price gains. Homes sold in 18 days on average, a record low.

Home sales are 12.3 percent higher than one year ago when they first started to fall because of the pandemic. Home inventory was at 1.07 million properties, down by 28.2 percent.[6]

Environmental Regulatory Requirements

Cheyenne Light and Black Hills Power closely monitor pending environmental regulations and requirements. From this, the utilities make action plans and determine the costs to comply with any pending regulations.

Federal and state environmental issues currently being tracked: climate change (electric utilities and transportation sectors), regional haze, water, and the Office of Surface Mining's coal combustion residuals rule relating to coal ash disposal.

Climate Change and the Paris Climate Agreement

The Biden administration intends to advance its climate and energy goals through executive actions as well as legislation.

Addressing climate change is one of the administration's top priorities. On the day of his inauguration, the President signed two executive orders focused on climate objectives. Both executive orders are expected to have significant impact on the fossil fuel industries, alternative energy industries, and the domestic economy. It remains to be seen if these executive orders will result in legislation. Nonetheless, these issues must be closely monitored to determine the impact on resource planning.

One executive order, Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, among its many provisions, established a Working Group on the Social Cost of Greenhouse Gases. This working group is directed to publish estimations on the social costs of carbon, nitrogen oxide (NOx), and methane, and make recommendations to the administration on how federal agencies should incorporate the social costs into the regulatory decision-making processes.[7]

A second executive order, Tackling the Climate Crisis at Home and Abroad, is a sweeping executive order focusing on the administration's climate plan and energy-related issues. It calls for achieving the goal of net-zero GHG emissions economywide by 2050, and within the electric power sector by 2035. This executive order establishes the White House Office of Domestic Climate Policy. The goal of this office is to develop an approach to climate change where every governmental agency decision considers the impacts of climate change and GHG emissions.

6 https://www.nar.realtor/newsroom/housing-market-reaches-record-high-home-price-and-gains-in-march

7 https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/executive-order-protecting-public-health-and-environment-and-restoring-science-to-tackle-climate-crisis/

Other provisions involve a plan to procure zero-emission vehicles, double offshore wind production by 2030, eliminate fossil fuel subsidies in 2022 and beyond, and identify opportunities to spur the innovation, commercialization, and deployment of clean energy technology and infrastructure. In addition, this executive order affirms the administration's intent to rejoin the Paris Agreement to the United Nations Framework Convention on Climate Change (Paris Agreement), a legally binding international treaty.[8]

The administration organized and hosted the virtual Leaders' Summit on Climate April 22–23, 2021, which was attended by 40 world leaders, including those from the world's 17 largest economies.[9] On the first day, the administration fulfilled its promise by officially rejoining the Paris Agreement. The administration also launched a whole-of-government process, organized through a National Climate Task Force, to establish multi-sector GHG emissions reduction goals for 2030 and new goals every five years through 2050. This new 2030 emissions goal, known as the nationally determined contribution (NDC), is a formal submission to the United Nations Framework Convention on Climate Change. With the NDC in hand, the administration intends to participate in the November 2021 Conference of Parties in Glasgow, Scotland, to update international climate goals.

To attain net-zero electricity by 2035, the administration intends to deploy zero carbon emissions electricity generating resources, transmission, and energy storage, and leverage the carbon free energy potential of power plants retrofitted with carbon capture and existing nuclear. The administration also intends to support efficiency upgrades and electrification in buildings through retrofit programs, wider use of heat pumps and induction stoves, and adoption of modern energy codes for new buildings.[10]

Climate Change Legislation and Regulation

Energy Efficiency and Clean Electricity Standard

In coordination with the current majority in Congress, the administration is proposing legislation designed to achieve net-zero goals. While details of the proposed legislation remain subject to the legislative process, initial concepts contemplate GHG emissions reduction compliance goals as well as carbon and other emissions pricing through an Energy Efficiency and Clean Electricity Standard. The emissions limits and pricing policies would be coupled with new or an extension of existing incentives to encourage adoption of non-GHG emitting resources, such as renewables. Concepts also look to create incentives for research, development, and deployment of advanced energy technologies, including CCUS, battery storage, renewable natural gas, and hydrogen.

8 https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/

9 https://www.state.gov/leaders-summit-on-climate/

10 https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/

CLEAN Future Act

Congress is currently considering energy and climate legislation. On March 2, 2021, the House of Representatives formally introduced a revised version of the Climate Leadership and Environmental Action for our Nation (CLEAN) Future Act. This bill, if enacted, would set a national standard for a 50 percent reduction in GHG emissions from 2005 levels by 2030 and a net-zero GHG economy by 2050 in four business sectors: power, transportation, buildings, and industrial.

Other provisions include:

- Establishing a federal clean electricity standard requiring retail sellers of electricity to ensure that 100 percent of sales are from zero-emitting generation resources by 2035, with an interim requirement for 80 percent clean electricity by 2030.
- Creating a credit system for compliance that awards full credits for zero-emission power generation and partial credits for generation with emissions below specified carbon-intensity benchmarks. Under the proposal, the EPA would administer a credit trading program between generators and retail suppliers. To comply, retail suppliers would produce or acquire credits to reach the annual clean electricity standard.
- Allowing retail suppliers to make Alternate Compliance Payments (ACP) starting at $40 in 2023 and escalating each year at a rate of three percent plus inflation. ACPs are determined on a 1:1 basis with credits, which effectively sets a ceiling price for credits.
- Phasing out the ability of fossil fuel power plants to earn partial credits from 2030 to 2035 and requiring accounting for upstream emissions attributable to gas-based generation.

The process depends on many variables, including whether any legislation considers regional, economic, reliability, and environmental impacts. Ultimately, the outcome depends on congressional support.

Absent congressional action, the administration may choose to advance GHG emissions and other climate policy through regulatory or other executive action. To better understand the implications to customers, Black Hills Power and Cheyenne Light conducted analysis of the CLEAN Future Act in the IRP.[11]

Risk Analysis of Pending Federal Policies

In evaluating pending Federal policies, the IRP models future resource plan scenarios and considers opportunities and risks to continue safe, reliable, cost-effective, and sustainable energy service to customers.

Federal policies present opportunities:

- Infrastructure modernization and improvement incentives (financial and regulatory consideration) for transmission and delivery systems.

11 The results of this analysis are described in Chapter 8: Portfolio Analysis and Selection.

- Advanced energy research and development incentives, including funding for emissions-free technologies such as carbon capture, hydrogen, battery storage, renewables, and energy efficiency.

In contrast, federal policies present risks:

- Emissions limits and restrictions in advance of current commitment and asset timeline, forcing early retirement, potential impacts to resiliency, reliability, and costs.
- Increased costs and limiting the ability to ensure affordability.
- Resource constraints resulting from access and permitting restrictions.

STATE POLICIES AND ECONOMIC CONDITIONS AFFECTING CHEYENNE LIGHT

The Cheyenne Light service territory has experienced positive load growth due to favorable economic conditions. Many large employers in the area have had a direct impact on this growth.

Economic Conditions

The state of Wyoming has experienced unemployment trends impacted by the COVID-19 pandemic, with a high of 8.5 percent in May of 2020, now stabilized between September 2020 and March 2021 to 5.3 percent.

In Wyoming, the notable loss of jobs in the fossil fuel industry since early 2016 has had an impact on this statewide trend. As of January 2021, Campbell County (home to the Gillette Energy Complex) and Laramie County (location of Cheyenne) have unemployment rates of 7.0 and 4.5 percent, respectively. Oil prices reached record lows in April 2020, causing a large decrease in oil activity in both counties.

COVID-19 affected nearly every aspect of life across the state of Wyoming. Some areas of the economy, like tourism, were hindered by shutdowns and travel limitations, while other areas, like real estate and general construction, saw improvements.

The Cheyenne Light service territory has experienced growth because of the favorable economic conditions. In Laramie County, both total taxable sales and total retail sales increased in 2020. Total taxable sales rose 5.9 percent from 2019 to 2020. Total retail sales rose just 0.4 percent during this same time, resulting in an increase in sales and use tax receipts of 5.3 percent from 2019 to 2020.[12]

12 These factors influence the econometric data forecasts used in the load forecasting process described in Chapter 4: Integrated Resource Planning Process.

Legislation

The Wyoming legislature recently passed four bills that directly impact Cheyenne Light: Senate File 159, House Bill 166, Senate File 152, and House Bill 200. The first three bills are discussed in the following sections; House Bill 200 is discussed in "Reliable and Dispatchable Low-Carbon Energy Standards" on page 03-9.

Retirement of Coal-Fired Generation

Senate Bill 159 outlines procedures for selling, rather than retiring, coal-fired generation; it became effective on July 1, 2019. The bill mandates utilities make a good faith effort to sell coal-fired plants at a fair rate rather than retire them.

The bill exempts an entity purchasing an otherwise retiring coal-fired electric generation facility from regulation as a public utility. It requires a public utility to purchase electricity generated from the purchased otherwise retiring coal fired electric generation facility if it is offered at a specified rate as determined by the Wyoming Commission.

Senate File 159 provides that the rates charged by an electric utility shall not include any recovery of costs associated with new electric generation facilities built to replace the electricity generated from retired coal-fired electric generating facilities unless the Wyoming Commission determines the electric utility made a good faith effort to sell the facility to another entity prior to retirement.

In 2020, the bill was amended to allow an entity buying an otherwise retiring coal facility to sell directly to customers of that utility who take service above 1 MW to provide for a customer base to the new owners.

The Wyoming Commission has initiated rulemaking and Black Hills Energy submitted comments.

Utilities Presumption Against Facility Retirements

House Bill 166 establishes a rebuttable presumption against the retirement of a coal-fired or natural gas-fired electric generation facility.

The Wyoming Commission cannot authorize or approve a retirement unless the public utility proves three items: (1) there are cost savings to customers, (2) reliability is not adversely impacted, and (3) sufficient dispatchable baseload power remains. Before approving a retirement, the Wyoming Commission must also consider how a nationwide energy shortage would affect Wyoming customers.

A public utility that retires a coal-fired or natural-gas fired generator without rebutting the presumption is subject to cost recovery limitations. These limitations include any recovery or earnings on the capital costs included in rates associated with new generation facilities built to replace the retired generation.

The bill does not apply to electric generation facilities closed under two conditions: (1) as required by federal law or (2) closed because federal environmental requirements prevent the facility from cost-effective operation. The act requires the Wyoming Commission to enact rules to implement its provisions.

Building Codes and Forced Electrification

Senate File 152, effective July 1, 2021, prevents cities, towns and counties from banning the connection or reconnection of a public utility provided electric, natural gas, propane, or other energy utility service for a home or business.

Project to Reduce Carbon Emissions from Fossil Fuel Generation

Cheyenne Light and Black Hills Power proactively seek solutions to reduce carbon emissions from fossil fuel generation. In response to a Wyoming Energy Authority request, Cheyenne Light submitted a proposal for a pilot hydrogen demonstration project at the Cheyenne Prairie Generating Station (CPGS) in partnership with General Electric, Black & Veatch, and Tallgrass. The University of Wyoming supported the proposal.

The proposed demonstration project aims to advance new technology that utilizes hydrogen fuel blended with natural gas to cost-effectively reduce carbon emissions. A number of existing carbon reduction technologies essentially cost the same as carbon capture, utilization, and storage (CCUS) technology.[13]

Successful demonstration of the pilot would set the stage for the first hydrogen fuel technology in Wyoming, a critical opportunity for transforming Wyoming coal and natural gas fired power plants to efficiently address carbon capture needs. Dispatchable fossil fueled generation is critical for system reliability with higher penetrations of renewable energy integration. Innovative pilot programs, such as this demonstration project, will help prepare for long-term future resource needs.

The Wyoming Energy Authority will award the selected proposal in July 2021.

Data Centers

The state of Wyoming provides financial incentives for siting and expanding data centers. This growth creates an opportunity to expand Cheyenne Light's rate base and diversify its generation mix.

Data centers receive a sales tax exemption on equipment and power purchases over $2 million if investments in capital construction or rent exceed $50 million.[14]

Currently, there are five data centers in the Cheyenne Light service territory that employ approximately 200 people, with an estimated additional 150 jobs to support data center operations (not including construction). These data centers contribute $82 million annually to the Wyoming gross domestic product and since opening, have spent $1.5 billion in capital

13 Identified in Black & Veatch's Busbar Cost Study; see Appendix D.

14 For details on the sales tax exemption for data centers, see Appendix M: Data Center Impact Study.

investments, paid $82.6 million in total employee wages, paid $18.7 million in sales taxes, and paid $40.6 million in property taxes.

ECONOMIC CONDITIONS AFFECTING BLACK HILLS POWER

The Black Hills Power service territory (western South Dakota, northeastern Wyoming, and southeastern Montana) saw fewer economic impacts. March 2021 unemployment rates fell to under pre-pandemic levels to 3.4 percent. Average weekly wages, hotel occupancy, and airport passengers all increased during the monthly reporting cycle.

The city of Rapid City issued 5,598 building permits in 2020, second only to 5,906 permits issued in 2013. Permit valuation in 2020 totaled $275 million. The Rapid City area enjoys low unemployment, increasing wages, high consumer spending, and increased rentals. Growth is hindered, however, by a tight real estate market. The arrival of the B-1B long-range, multi-role bomber at the Ellsworth Air Force base will lead to an increase in assigned military personnel in the Rapid City area.[15]

CARBON CAPTURE, UTILIZATION, AND STORAGE

Carbon capture, utilization, and storage (also referred to as carbon capture, utilization, and sequestration) technologies[16] are currently being researched and tested to remove CO_2 from air emissions. Carbon capture separates and entraps CO_2 from large stationary sources, including power plants, industrial boilers, refineries, and natural gas wells. Carbon sequestration captures and securely stores CO_2 that would otherwise be emitted and remain in the atmosphere.

Captured CO_2 must be stored so that it cannot be emitted back into the atmosphere. Such storage needs to be: (1) long-term, preferably for hundreds to thousands of years, (2) at minimal cost including the cost of transportation to the storage site, (3) with no risk of accident, (4) with minimal environmental impact, and (5) in compliance with laws or regulations. Potential storage media include geologic sinks and the deep ocean. Geologic sinks include deep saline formations (subterranean and sub-seabed), depleted oil and gas reservoirs, enhanced oil recovery, and non-mineable coal seams. Deep ocean storage includes direct injection into the water column at intermediate or deep depths.

Notably, the State of Wyoming has constructed the Integrated Test Center at the Dry Fork Station near Gillette. Starting in the fall of 2019, various companies began using the Integrated Test Center to test several technologies for separating and sequestering CO_2. One company

15 These factors influence the econometric data forecasts used in the load forecasting process described in Chapter 4: Integrated Resource Planning Process.

16 Howard Herzog and Dan Golomb, *Carbon Capture and Storage from Fossil Fuel Use*, as published in the *Encyclopedia of Energy*, 2004.

tested the use of membranes and solid sorbents to separate CO_2 from the flue gas of a coal-fired power plant. Another company is planning to test a carbon capture technology.

Several other projects for researching beneficial uses of CO_2 began in 2020 including:

- Producing methanol, a common fuel and petrochemical feedstock, using a novel catalyst.
- Producing chemicals and bio-composite foamed plastics.
- Producing solid carbonates with applications to building materials.
- Utilizing direct sunlight to produce environmentally responsible polymers and chemical intermediaries for industrial partners.
- Producing building materials that absorb CO_2 during the production process to replace concrete.

Two bills that support CCUS technology are discussed in the next two sections.

Reliable and Dispatchable Low-Carbon Energy Standards

In 2020, the Wyoming legislature passed House Bill 200 requiring the establishment of energy production standards.

The bill requires the Wyoming Commission to establish energy portfolio standards requiring a specified percentage of electricity to be dispatchable, reliable, and low carbon by 2030. Low-carbon electricity is generated using CCUS technology that results in less than 650 pounds of carbon dioxide emissions per MWh of electricity generated.

The bill requires the Wyoming Commission to set intermediate energy production standards and require public utilities to demonstrate in each IRP the steps the utility is taking to achieve those standards. The bill prohibits rate recovery for new electric generation facilities built to replace retiring coal-fired electric generation facilities unless the utility demonstrates it is taking steps to achieve established generation standards.

If a public utility achieves or satisfactorily progresses toward achieving the established standards, the utility can seek rate recovery for the cost of CCUS technology, apply to allow revenues from the sale of captured CO_2 to be returned to the utility's shareholders and seek up to a two percent surcharge from utility customers.

The bill requires the Wyoming Commission to report to the legislature every two years beginning in 2023 regarding the implementation of the standards and recommendations on continuing, modifying or repealing the standards. The Wyoming Commission has not yet established standards.

Cheyenne Light analyzed potential impacts of House Bill 200 in candidate resource C9. House Bill 200 is also applicable to Black Hills Power. The 2021 IRP, however, does not include a specific scenario designed to analyze installing CCUS on a Black Hills Power generation resource. Instead, the option to add carbon capture to Neil Simpson Unit II was included in all scenarios. This option was not selected by the Capacity Expansion model a in any scenario. Black Hills Power will monitor the implementation of House Bill 200 and include CCUS analysis in future IRPs as appropriate.

Storing CO_2 and Lowering Emissions (SCALE) Act

The SCALE Act, re-introduced in Congress with the bipartisan support of a diverse group of influential legislators, seeks to enable CO_2 transportation and storage infrastructure required to scale up carbon capture, removal, use, and storage across domestic industries. Wyoming's governor, together with three other governors, sent Congress a letter on behalf of seven signatory states, in "strong support" of the bill.

If enacted, the federal government would act on implementing critical technological innovations to affect a cost-effective strategy for deploying CCUS across the county. The bill would:

- Establish a program to provide flexible, low-interest loans for CO_2 transport infrastructure projects and grants for initial excess capacity on new infrastructure to facilitate future growth.
- Realize economies of scale by reducing the overall costs associated with buildout of an interconnected system.
- Support development of saline geologic storage resources, focusing on projects that could serve as regional hubs for the deployment of large-scale saline geologic storage, and support implementation of the EPA permitting program on CO_2 injection for secure geologic storage.
- Authorize grants for states and municipalities to procure low- and zero-carbon products derived from CO_2 and carbon oxides.

Several factors inhibit the widescale adoption of CCUS: insufficient network for cost-effectively transporting CO_2, the low number of qualified geologic storage sites, inadequate sources of funding and tax incentives, and the lack of necessary infrastructure to correct these problems.

The SCALE Act not only has bipartisan support in Congress and in state governments but is also endorsed by a broad coalition of labor, environmental, and industry stakeholders. The IRP modeling, however, does not consider the SCALE Act.

FUEL MARKETS AND TRENDS

How Cheyenne Light and Black Hills Power purchase, transport, and use coal and natural gas impacts operations.

Coal Trends

Historically, most base load energy in this country was provided by coal-fired generation. That trend changed in 2007. Since then, coal has given way to increased renewable generation. By 2020, coal generation dropped to the same level as 1972.

Figure 03-1 depicts the generation trend over the past 70 years as published by the United States Energy Information Administration (EIA) in February 2021.

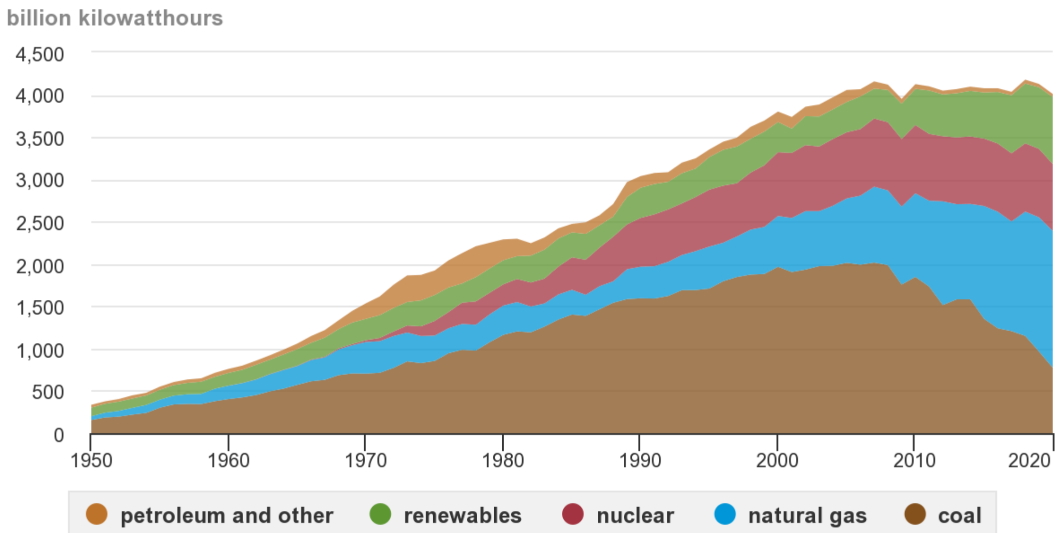


Figure 03-1. United States Electricity Generation by Major Energy Source[17]

An area of long-term, growing concern in the use of coal as a fuel for electricity generation is that it produces more CO_2 emissions per unit of energy output than other fuels (for example, about twice as much as natural gas). Because of policy, market, and societal forces, coal currently faces competitive pressure from lower-carbon resources such natural gas, renewable resources, and other emerging technologies. Existing coal-fired generation remains the largest producer of electricity for both Cheyenne Light (55.15 percent) and Black Hills Power (38.95 percent).

17 Source: https://www.eia.gov/energyexplained/electricity/electricity-in-the-us.php.

Natural Gas Supply Trends Over the Long-Term

Shale gas technology has increased the amount of recoverable North American natural gas, enabling producers to access vast supplies of shale gas. New technology that provided lower cost access to shale gas caused total U.S. production to grow substantially.

Figure 03-2 illustrates the production of natural gas.

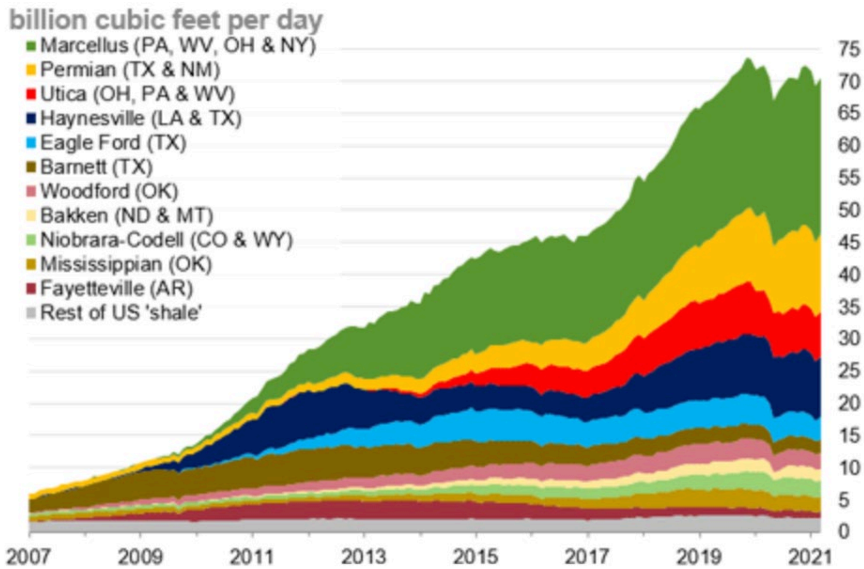


Figure 03-2. U.S. Natural Gas Production, 2007–2021[18]

Forecasted higher or lower production levels will correlate with forecasted gas prices being higher or lower than expected. The IRP analysis in the Base, High Gas, and Low Gas scenarios address this uncertainty.

Current Natural Gas Supply

The Black Hills Energy Gas Supply team procures natural gas for all of Cheyenne Light's and Black Hills Power's natural gas-fired generating units. The team purchases and establishes risk mitigation measures for natural gas, and contracts services for transporting and storing it. The team designs gas fired generating facilities with redundant natural gas supply to meet regulatory requirements for operating reserves and minimize operating reserve costs to customers. The redundant natural gas supply ensures system reliability.

Cheyenne Light and Black Hills Power purchase natural gas in the day-ahead market to meet expected customer electric energy requirements for the following day. Natural gas generation is then dispatched as needed. Actual consumption, however, may be higher or lower than forecasted. The differences in actual versus forecasted natural gas consumption are settled through a balancing process with the pipeline company.

18 Source: https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php.

Cheyenne Light and Black Hills Power contracts for a total of 7,100 dekatherms per day of firm transportation of natural gas on the Southern Star Central Gas Pipeline (SSCGP) for the CPGS units. Of that total, 2,900 dekatherms are allocated for Cheyenne Light and 4,200 dekatherms for Black Hills Power. Cheyenne Light and Black Hills Power hold interruptible transportation contracts for incremental flow when loads exceed 7,100 dekatherms. The interruptible transportation contracts have proved to be reliable. Since these contracts are interruptible, however, SSCGP can cut supply at any time, leaving an insufficient supply for the natural gas generators. Cutting off supply is more likely during the winter months when natural gas demand is higher.

Black Hills Power does not procure firm transportation on the interstate pipeline to supply natural gas to its generating units in Gillette or Rapid City, but instead uses interruptible transportation service. These generating units include the Ben French, Lange, and Neil Simpson simple cycle CTs. These interruptible transportation contracts have been largely reliable over the years.

When the non-firm natural gas supply is not available, the utilities rely on the electric power energy market to ensure system reliability. Since the cost of firm gas supply in this area is quite expensive, the utilities rely on the geographic diversity of their generating assets to help reduce risk by ensuring gas supplier diversity. In addition, Black Hills Power has some dual fuel natural gas generators. Because Cheyenne Light and Black Hills Power have been predominantly reliant on coal-fired generation, the current gas supply management practices have served customers optimally by providing a cost-effective and reliable energy supply.

Natural Gas Supply Risk Analysis and Mitigation Planning

Maintaining a reliable supply of natural gas becomes increasingly important as Cheyenne Light and Black Hills Power transition their fuel supply from coal to natural gas and renewable resources. The utilities continue to see impacts to the natural gas and electric power markets caused by unplanned and naturally occurring events—wildfires, storms, and market driven constraints such as power line or gas pipeline outages. Public policy changes are also a factor. For example, the Biden administration issued an executive order implementing a moratorium on new oil and gas leases on federal lands that has the potential to impact natural gas supply and cost. The moratorium represents a pause on new oil and gas development and initiates a new review of existing fossil fuel leasing and permitting practices. Restrictions on natural gas drilling on federal lands could limit supply and lead to increased prices. Based on these risks, Cheyenne Light and Black Hills Power will evaluate and may implement risk mitigation changes to their current gas supply practices.

Cheyenne Light and Black Hills Power will evaluate gas supply practices and consider a number of gas supply options to manage the future risks and to ensure safe, cost-effective, reliable energy supply.

Liquified Natural Gas. LNG provides an alternative to natural gas from interstate pipelines. Tanker trucks deliver LNG to generating sites where it is stored in on-site tanks for use when needed. The typical cost for transporting and gasifying LNG is about $5–$6 per dekatherm.

Depending on the cost of natural gas, LNG costs can be as much as 200 percent higher than traditional natural gas delivered in pipelines.

Natural Gas Firm Storage. Firm storage services for natural gas purchased from the interstate pipelines provide a hedge against both price and delivery risk. When natural gas supply is limited or interrupted, firm storage with firm pipeline transportation enables the utilities to withdraw and deliver natural gas up to a pre-determined maximum daily withdrawal quantity (MDWQ). Natural gas storage also hedges risk against price. Natural gas can be stored when prices are low—typically during the shoulder months in the spring and fall—and withdrawn when prices are high. Natural gas prices are high typically in the winter when heating demand is high and sometimes in summer when cooling demand is high. At CPGS, the SSCGP does not currently have any firm storage available for purchase. At Gillette and Rapid City, WBI Energy Transmission does have firm storage available for purchase.

Physical and Financial Instruments. Many different physical and financial instruments are available to hedge price risk. These instruments include seasonal fixed price purchases, storage services, physical call options, and derivatives.

- **Seasonal Fixed Price Purchases:** Gas is purchased at a fixed price before winter or summer for the upcoming season. For example, the utilities would agree to purchase natural gas in the summer at the prevailing fixed price, then from November through March, the utilities would receive the natural gas from the supplier at the agreed-upon fixed price.
- **Storage Services:** The storage services act as a hedge against price risk. Storing LNG offers a similar hedge against rising prices.
- **Physical Call Options:** Cheyenne Light and Black Hills Power pay a counterparty a demand fee for the right, but not the obligation, to purchase daily gas at a negotiated price.
- **Derivatives:** Several derivative products are available. The financial call option, one of the most used, protects against prices going above an agreed natural gas ceiling price. The call option is a risk because it requires a premium to be paid against a specific strike price. For example, an agreement is made for a call option with a strike price of $4.00 for up to 5,000 dekatherms with a premium cost of $.50. If the option is called, the buyer pays $4.00 per dekatherm for up to 5,000 dekatherms even when prices rise above this strike price. If prices fall below $4.00 per dekatherm and the option isn't called, the buyer must still pay the $.50 premium for 5,000 dekatherms. The buyer can still call the option but would be overpaying based on the lower market price. In essence, the price of natural gas is capped in a rising market, while still allowing the buyer to purchase gas in a falling market. The call option is purely a financial transaction, as physical supply is secured separately.

Dual Fuel Options. Dual fuel options exist for certain types of generators. For example, two of Black Hills Power's gas fired CTs are capable of running on natural gas or liquid diesel fuel. Liquid fuel is less expensive to store on-site and enables the CTs to operate in the event of a disruption in the natural gas fuel supply.

Cheyenne Light and Black Hills Power understand these future risks and the increased reliance on natural gas to meet customers' energy needs must be effectively handled. The utilities are prudently reviewing gas supply management practices and will continue to communicate any revised practices in future IRPs.

Renewable Generation Trends

Since the 1990s, the amount and percent of energy from renewable resources—biofuels, geothermal, solar, and wind—has increased three-fold to about 17 percent of national generation. Renewable generation plays an important role in reducing GHG emissions through new installations and replacement of fossil fuel generation. The EIA projects that nation-wide renewable energy consumption will continue to increase through 2050.

Figure 03-3 depicts the renewable generation trend over the past 70 years as published by the EIA in February 2021.

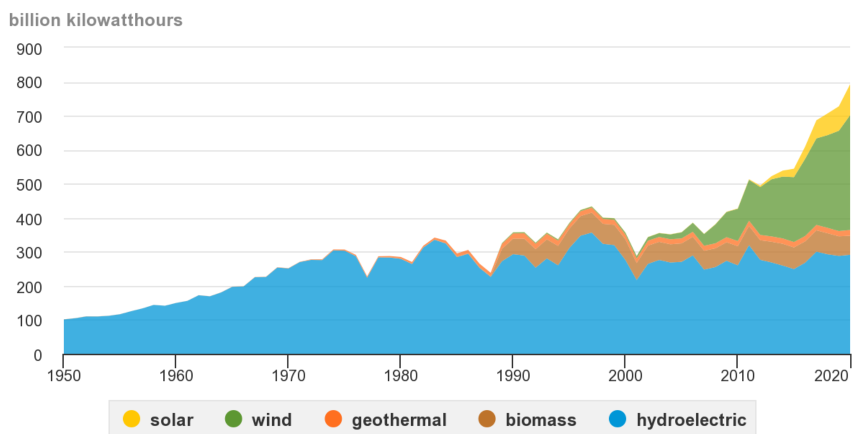


Figure 03-3. United States Electricity Generation from Renewable Energy Sources

ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

Cheyenne Light's DSM Programs

Cheyenne Light continues to seek ways to reduce retail system peak demand through demand-side management (DSM) plans. These include a combination of energy efficiency, conservation, load management, and demand response (DR) programs.

Cheyenne Light's tri-annual DSM plan, originally implemented for 2016–2018, was renewed for 2019–2021. This portfolio of programs—for residential, commercial, and industrial—is cost-effective based on the IRP modeling assumptions. To meet the overall DSM plan goals, each program:

- Achieves energy savings directly attributable to program activities.
- Reduces end-use electric and natural gas consumption to save money for customers and provide energy and demand resources to the grid.

- Increases residential and commercial customer awareness of energy efficiency opportunities.
- Improves relationships with customers, trade allies, and stakeholders by providing value-added energy-efficiency services, training and education, hardware, and other technical support.
- Supports the local economy by freeing capital through energy savings, creating business opportunities for equipment dealers, installers, and other energy efficiency end-use sectors, and facilitating energy efficiency projects.

Cheyenne Light offers four residential DSM programs during the 2019–2021 implementation cycle.

Residential Solutions. Offers a comprehensive, whole house approach to energy retrofits through a variety of cost-effective measures. These include energy evaluations; natural gas and electric direct installs; whole house insulation and air sealing options; window and patio door replacements; natural gas furnace and boiler replacements; natural gas water heaters; electric and natural gas heating, ventilation, and air conditioning (HVAC) tune ups; central air conditioning; and air source heat pump replacements

Consumer Products. Provides a pathway for customers to purchase energy efficient products at local retail stores, outside of a contractor-driven installation, to increase participation and savings. Measures include refrigerator and freezer recycling, new Energy Star appliances, high efficiency lighting, smart power strips and thermostats, room air conditioners, dehumidifiers, and air purifiers.

Residential New Construction. Promotes the construction of Energy Star certified homes by developing strong relationships with local builders. This includes incentives for constructing Energy Star qualified homes as well as additional rebates for installing high efficiency HVAC and water heating equipment.

Low Income Audit and Weatherization. Provides natural gas and electric energy savings measures to a previously underserved market with high savings potential. Installed measures include high efficiency lighting, low flow aerators and showerheads, weather stripping, air sealing, and duct sealing.

Cheyenne Light also offers three commercial and industrial DSM programs during the 2019–2021 implementation cycle.

Commercial Prescriptive Rebate Program. Offers pre-determined prescriptive incentives to commercial customers interested in reducing energy costs within their businesses. The intent is to quantify the savings and value of energy efficiency measures and process improvements. It consists of natural gas and electric incentives for measures such as lighting, motors, cooking and ventilation equipment, and heating and cooling equipment.

Commercial Custom Rebate Program. Helps commercial and industrial customers save energy through a broad range of energy efficiency options not explicitly offered through the prescriptive rebate program (such as lighting and HVAC retrofits).

Small Business Direct Install. Alleviates first-cost market barriers by creating incentives for small businesses to install energy efficient upgrades. It includes an in-person assessment with recommendations and financing options for projects such as lighting, cooking, and refrigeration.

Black Hills Power DSM Programs

Black Hills Power's South Dakota tri-annual plan for 2017–2019 resulted in reduced demand and energy savings. On September 1, 2020, the utility discontinued its South Dakota DSM program because of the inability to establish a portfolio of energy efficient offerings that are and that will remain cost-effective. Black Hills Power does not have a Commission approved DSM program in the jurisdictions of Wyoming and Montana.

WIND, SOLAR, AND BATTERY STORAGE RESOURCE POTENTIAL

The Energy Policy Act of 1992 originally enacted the production tax credit (PTC), which has been the primary production-based incentive for wind energy and essential to the industry's research and development. The original PTC legislation expired in July 1999 but has been expanded and extended several times through many different laws.

With the Protecting Americans from Tax Hikes Act of 2015 (PATH), Congress extended the PTC for five years, reducing its value by 20 percent each year, with a complete phase out by the end of 2020. The PTC's value is based on the year construction begins rather than when the facility begins production. PATH applies retroactively to January 1, 2015. The phase-down begins for wind projects commencing construction after December 31, 2016.

PATH extended the tax credit for other eligible renewable energy technologies beginning construction through December 31, 2016.

The Taxpayer Certainty and Disaster Tax Relief Act of 2019 extended the PTC for qualified wind projects that began construction in 2020. The Consolidated Appropriations Act of 2021 extends the PTC for a qualified wind facility that starts construction in 2021. The PTC amount is reduced by 40 percent for qualifying projects that start construction in 2020 and 2021.

The Consolidated Appropriations Act (CAA) of 2016, extended the solar investment tax credit (ITC). This legislation, which was signed into law on December 18, 2015, extends the 30 percent ITC for both residential and commercial projects. The act also changed the previous "placed in service" standard with a "beginning of construction" standard, which is intended to provide facility developers with greater certainty. Like the PTC legislation, provisions to lower the credits over time were included in the bill. The new legislation decreases the ITC first to 26 percent, then to 22 percent, and finally to 10 percent for commercial projects and zero percent for residential projects.

The CAA of 2021 modifies the ITC rules for qualified solar facilities by extending the period when the ITC is phased out. Table 03-1 details the phase out period for years when construction of a qualified solar facility begins.

Construction Start Year	Solar ITC
2020	26%
2021	26%
2022	26%
2023	22%
2024	10%

Table 03-1. Solar Generation Construction ITC

To qualify for a Solar ITC, facilities must be placed into service by December 31, 2025. Facilities placed in service after that date will only be eligible for the 10 percent ITC, regardless of when construction began.

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

Cheyenne Light currently has 45 MW of wind resources. Black Hills Power has 79.5 MW of wind and expects to add 80 MW of solar through a 20-year power purchase agreement (PPA) in 2022.

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 and spot markets is an important factor in how both Cheyenne Light and Black Hills Power operate and plan generation requirements. At times, the utilities can purchase less expensive energy through market purchases to serve short-term customer needs (rather than generate energy from utility owned generation). Such purchases reduce costs and result in substantial customer benefits.

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

Electric prices in the Western Electricity Coordinating Council (WECC) region have been low for the past several years. Low natural gas prices, adequate capacity supplies, and low load growth will likely keep prices at a low level in the near term.

The region has recently experienced volatility outside the control of the utilities. In February of 2021, Storm Uri caused a considerable spike in natural gas prices which consequently drove higher energy prices.

Last summer's rolling blackouts in California caused prices to elevate as far east as the Cheyenne Light and Black Hills Power service territories. Some tightening of these markets is assumed through the planning period and in the later years of the near-term need.

Weather, overall economic conditions, and resource supply availability—all of which can change quickly—drive demand uncertainties in the electricity markets. North American Reliability Corporations' (NERC) 2020 Long-Term Reliability Assessment includes over 10,000 circuit miles of planned transmission over the next ten years, as well as many planned additions of natural gas, wind, and solar resources. As such, WECC has an anticipated surplus of capacity through 2030.

LARGE CUSTOMER MARKET ENERGY TARIFFS

Cheyenne Light implements two tariffs to facilitate securing and accessing market energy for high-density loads: the large power contract service (LPCS) and blockchain interruptible service (BCIS). The LPCS tariff is for new customer load with expected capacity of at least 13 MW who agree to provide onsite generation that enables a back-up service for their load and maintains reliability. The BCIS is for interruptible loads expected to be at least 10 MW that can be interrupted at Cheyenne Light's discretion for a negotiated number of annual hours.

Cheyenne Light's system-level peak demand and energy forecasts exclude all LPCS loads and BCIS loads in IRP planning, since the tariffs do not require loads to be served with utility-owned generation resources. Black Hills Power's system-level peak demand and energy forecasts do not exclude any customer loads in its IRP planning.

WYODAK REGIONAL HAZE IMPACTS

The Wyodak coal-fired generating facility is jointly owned by PacifiCorp (80 percent) and Black Hills Power (20 percent). On January 10, 2014, the EPA issued a federal implementation plan (FIP) requiring the installation of selective catalytic reduction (SCR) on the Wyodak unit within five years to comply with the EPA's Regional Haze rule. Black Hills Power would be required to pay 20 percent of any modifications.

PacifiCorp appealed the EPA's action and, together with the State of Wyoming, negotiated with the EPA. Late in 2020 a settlement agreement was reached that limited the operating hours of Wyodak and required the installation of low-nitrogen oxide (NOx) burners. Following a public comment period that ended on March 1, 2021, PacifiCorp issued a response that, in summary, concluded the proposed settlement is prudent and should be finalized.

In its 2019 IRP, PacifiCorp included Wyodak as a resource through 2039 with the following description of future actions:

> If following appeal, EPA's final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.

This IRP assumes Wyodak is an available resource through 2039. Black Hills Power will continue to monitor PacifiCorp's actions related to Wyodak and update future IRPs as appropriate.

BALANCING AUTHORITIES—THE BACKBONE OF RELIABILITY

NAES Corporation and Energy + Environmental Economics (E3) conducted two studies whose findings could materially affect how Cheyenne Light and Black Hills Power operate in the future. NAES conducted a study to determine the feasibility of the utilities forming a new Balancing Authority (BA). E3 analyzed the potential benefits for both utilities to participate in the California ISO (CAISO) Western Energy Imbalance Market (WEIM) or the Southwest Power Pool (SPP) Western Energy Imbalance Service (WEIS) market.

Understanding the Western Balancing Authorities and Energy Markets

The Federal Energy Regulatory Commission (FERC) reports to the DOE as part of the United States Executive Branch of government. FERC is an independent agency that regulates high voltage interstate transmission of electricity and natural gas transportation, transmission open access, and the office of markets and reliability. FERC governs by delegating to the Electric Reliability Organization (ERO). The ERO is NERC.

NERC was established in 2007 as the ERO with oversight from FERC. NERC is responsible for developing and enforcing reliability standards. This compliance role allows NERC the ability to issue sanctions to the eight regional reliability entities across the United States, Canada, and the northern part of Mexico. NERC delegates authority to each of the regional entities including WECC. WECC is the region that governs reliability compliance for Cheyenne Light and Black Hills Power.

Figure 03-4 depicts a map of the NERC regions in North America, including the WECC region.

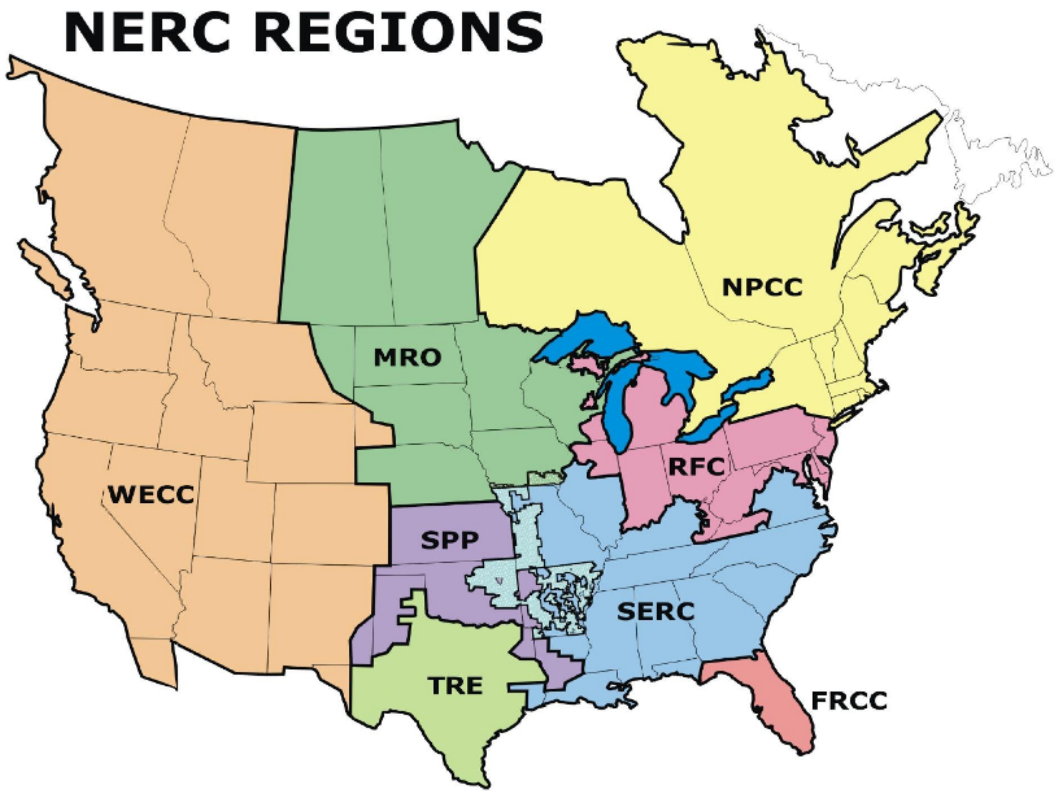


Figure 03-4. North America NERC Regions

In 2007, WECC was designated the regional entity for the Western Interconnect. WECC has been delegated authority from NERC for compliance and enforcement of the NERC standards. WECC coordinates the bulk electric system (BES) reliability for the Western Interconnect. WECC, headquartered in Salt Lake City, Utah, has responsibility for over 300 member organizations.

WECC is a 501c(4) nonprofit Utah corporation that, consistent with its Bylaws, follows two core missions:

- Reliability Mission: maintain a reliable electric power system in the Western Interconnect that supports efficient competitive power markets.
- Transmission Access Mission: assure open and non-discriminatory transmission access among members and provide a forum for resolving transmission access disputes between members consistent with FERC policies where alternative forums are unavailable or where the members agree to resolve a dispute using the mechanism provided in the Bylaws.

Each member organization within WECC operates within a BA. A BA is a set of resources and interchange meters. Traditional BAs have dispatchable generation, load, and interchange. Figure 03-5 lists the 38 BAs in WECC and their geographic location.

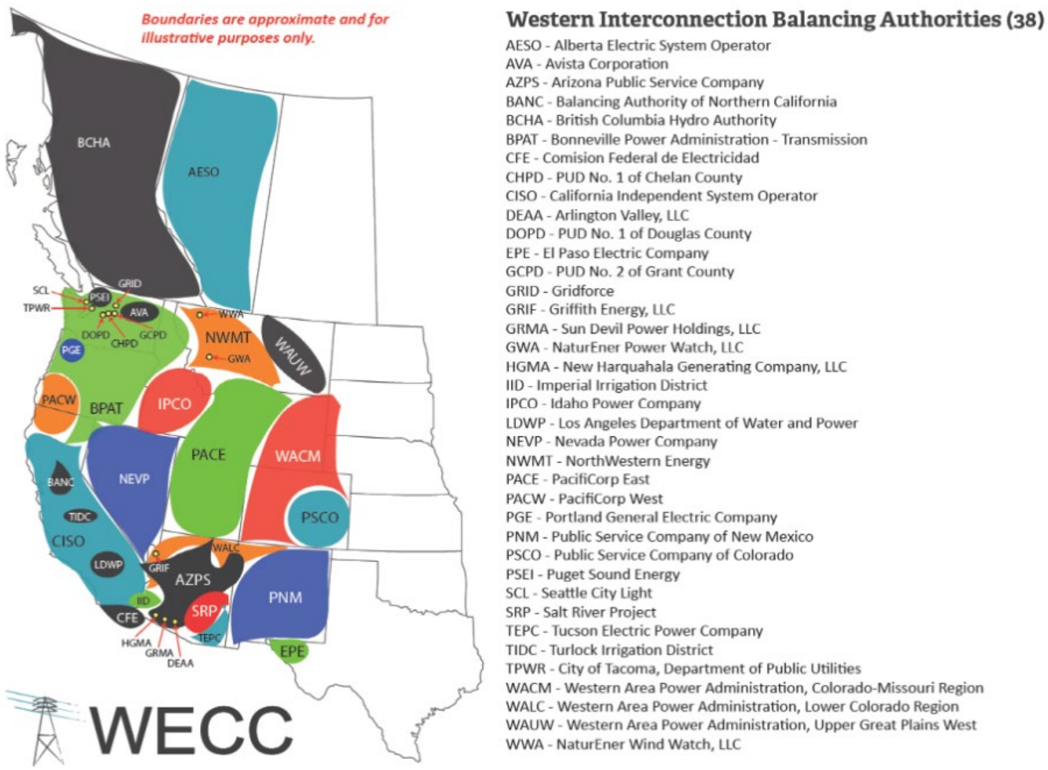


Figure 03-5. Thirty-Eight WECC Balancing Authorities

The basic responsibility of the BA is to balance load with transfers and generation, ensuring effective control of electrical frequency across the Western Interconnect. Short term balancing is focused on load-frequency regulation whereas long term balancing concerns load following. BAs utilize automatic generator control (AGC) to adjust generator loads over short time periods to provide these balancing services. To ensure consistency across the power system, NERC has established specific reliability standard requirements that are applicable to BAs. WECC conducts routine audits of the BAs to ensure they comply with all applicable NERC standards.

Figure 03-6 depicts a diagram of the BAs and their metered interchanges.

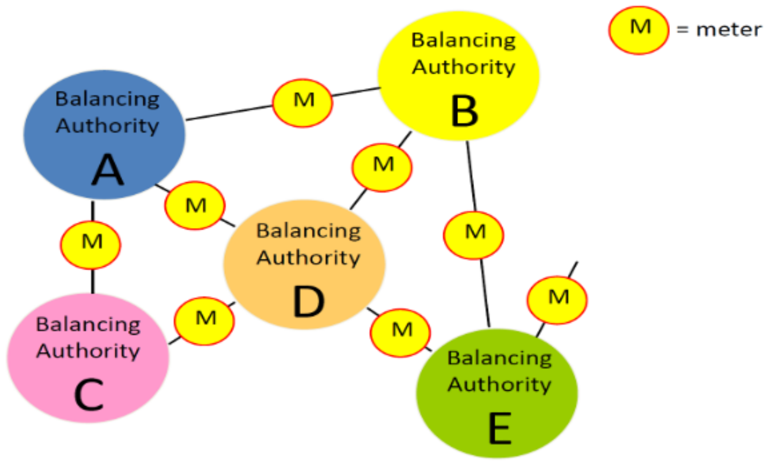


Figure 03-6. Balancing Authority Metered Interchange Depiction

Cheyenne Light and Black Hills Power must either provide or contract for BA services to ensure reliability and compliance. The utilities engaged NAES and E3 to analyze BA service options to provide the most economic long-term benefit to customers. The NAES study evaluated BA options, including Cheyenne Light and Black Hills Power forming a new BA. The E3 study considered which regional real-time energy market would provide the best overall customer benefits. The combined costs and customer benefits of the BA and market options inform the preferred long-term plan for BA services. They also support a plan for energy market participation that would provide the most economic customer benefit.

WAPA, Colorado Missouri (WACM) is the current BA for Cheyenne Light and Black Hills Power. The Western Area Power Administration–Rocky Mountain Region (WAPA–RMR) operates the WACM. Cheyenne Light and Black Hills Power are each transmission owners and transmission providers with separate open access transmission tariffs however, energy imbalance and other ancillary services are procured from the WACM BA under a single balancing authority agreement.

In the spring of 2019, WAPA–RMR began negotiations with the SPP to form a new energy imbalance market in the Western Interconnect that would become known as the SPP Western Energy Imbalance Service (WEIS) market. Cheyenne Light and Black Hills Power participated in an accelerated WEIS development process called the Western Joint Dispatch Agreement (WJDA). After reviewing drafts of the proposed WJDA participation agreements and tariff, the Cheyenne Light and Black Hills Power declined to participate in the WEIS market. The review of the proposed market structure, governance, and administrative fee allocation led to the determination that the WEIS would likely harm Cheyenne Light and Black Hills Power customers by imposing increased costs that would likely exceed the WEIS market benefits.

Despite the decision to not participate, Cheyenne Light and Black Hills Power pay a load ratio share of the WEIS administrative fees because of WAPA–RMR's decision to join the WEIS. Two costs—WEIS administrative costs and a WAPA-RMR administrative fee applicable only to non-WEIS BA customers—flow through the current balancing authority agreement effective January 1, 2021. These administrative fees are expected to exceed $1.8 million annually for Cheyenne Light and Black Hills Power combined.

Balancing Authority Feasibility Study

The NAES Balancing Authority Feasibility Study[19] explored alternative BA solutions for Cheyenne Light and Black Hills Power to avoid the impacts of WAPA–RMR's decision to participate in the SPP WEIS market.

The study analyzed three BA options for Cheyenne Light and Black Hills Power and evaluated the costs and benefits associated with each:

- **WAPA as BA.** Remaining in the existing contract BA services through WACM
- **Cheyenne Light and Black Hills Power as BA.** Both utilities forming a new BA and certifying with WECC.
- **PACE as BA.** Integrate with and take service from the PacifiCorp East BA.

Table 03-2 and Table 03-3 summarize the estimated low and high costs, respectively, for these three BA options.

Low Operating Cost Scenario: Services	WAPA as BA	BHE as BA	PACE as BA
1. Scheduling, system control, and dispatch	$316,416	Included in #2	$682,021
2. Reactive supply, voltage control from generation, and other	$213,551	$213,551	$213,551
3. Regulation	$2,008,546	Included in #5	$1,990,735
4. Frequency response service	Included in #3	$72,000	Included in #3
5. Imbalance/inadvertent interchange (96% imbalance coverage)	$406,248	$3,504,114	$ (514,386)
6. Reserves	$597,000	$597,000	$729,000
7. BA desk staffing	–	$553,000	–
8. Compliance and training staff	–	$308,000	–
9. IT staffing and systems	–	$201,920	–
10. Reporting, administration, and other costs	–	$320,600	–
Totals	$3,541,761	$5,770,185	$3,100,921

Table 03-2. BA Annual Operating Cost Comparison: Low Cost Scenario

19 See Appendix G: Balancing Authority Feasibility Study for the complete report.

High Operating Cost Scenario: Services	WAPA as BA	BHE as BA	PACE as BA
1. Scheduling, system control, and dispatch	$316,416	Included in #2	$682,021
2. Reactive supply, voltage control from generation, and other	$213,551	$213,551	$213,551
3. Regulation	$2,008,546	Included in #5	$2,101,199
4. Frequency response service	Included in #3	$600,000	Included in #3
5. Imbalance/inadvertent interchange (96% imbalance coverage)	$406,248	$5,325,368	$ (514,386)
6. Reserves	$2,334,300	$2,334,300	$729,000
7. BA desk staffing	–	$903,000	–
8. Compliance and training staff	–	$308,000	–
9. IT staffing and systems	–	$201,920	–
10. Reporting, administration, and other costs	–	$320,600	–
Totals	$5,279,061	$10,206,739	$3,211,385

Table 03-3. BA Annual Operating Cost Comparison: High Cost Scenario

The study found that Cheyenne Light and Black Hills Power are well positioned to form a BA. The estimated cost of that option, however, was nearly double that of remaining with WAPA or joining the PacifiCorp East BA. The study also found joining the PacifiCorp East BA could create customers savings relative to continuing with WAPA. By transitioning to the PacifiCorp East BA, Cheyenne Light and Black Hills Power would gain access to the CAISO WEIM market.

Given Cheyenne Light's current reliance on the WAPA transmission system, it may not be feasible to transition to the PacifiCorp East BA and participate in the CAISO WEIM. The most straightforward solution to joining the PacifiCorp East BA is to build new transmission connecting the Cheyenne Light transmission system to the PacifiCorp and/or Black Hills Power transmission systems. This would provide a direct link and transmission path for the delivery of ancillary services and market energy without the need for transmission service on the WAPA system.

Further, the current real-time market participation in the west is determined at the BA level. Cheyenne Light and Black Hills Power can only participate in the real-time market their BA has joined.

Real-Time Energy Market Participation Analysis

To determine the customer benefits of joining the CAISO WEIM or the SPP WEIS market, the utilities contracted with E3 to conduct an additional study of these two market options. The E3 analysis evaluated the economic benefits for joining either the CAISO WEIM or the SPP WEIS market. E3's experience evaluating energy markets is represented by over 14 studies completed since 2013 assessing market impacts and market participation.

Figure 03-7 is a map of the California ISO WEIM.

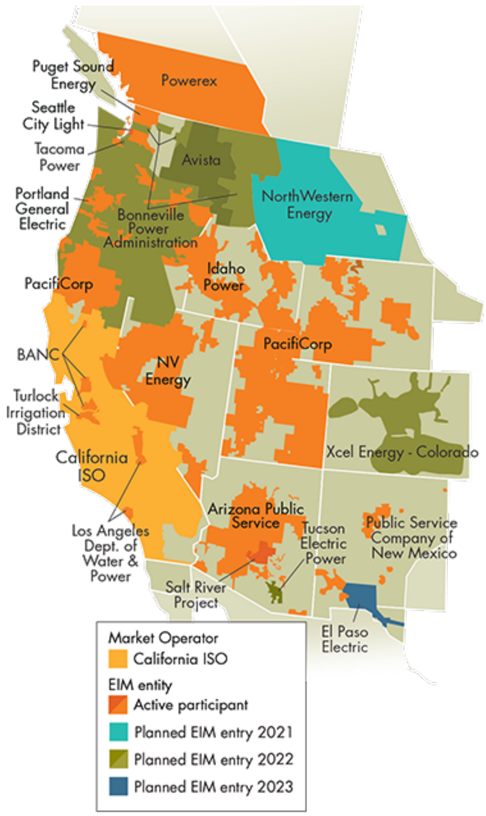


Figure 03-7. California ISO WEIM Map

Figure 03-8 is a map of the Southwest Power Pool WEIS Market.

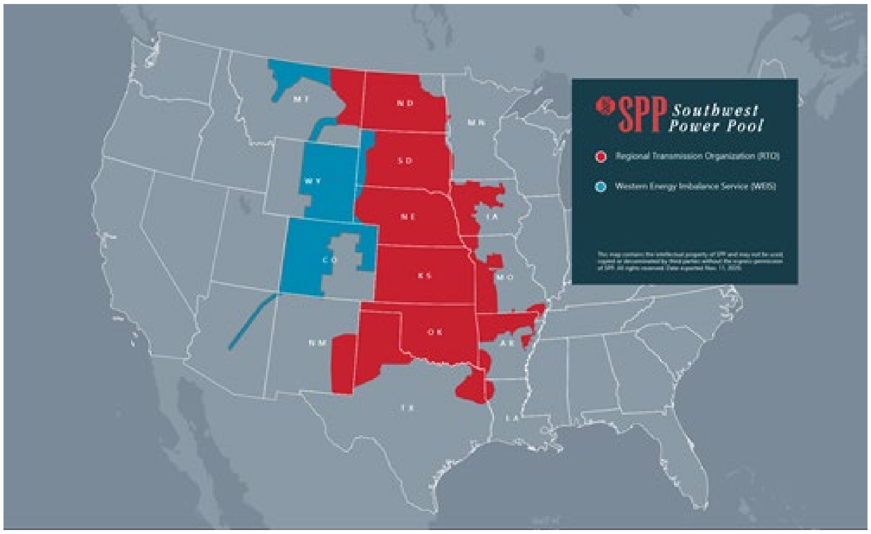


Figure 03-8. Southwest Power Pool WEIS Market Map

Two scenarios were analyzed: the 2019 historical benchmark and a 2025 future base scenario. In both scenarios, the analysis indicates that participating in both WEIM and WEIS would provide lower total energy costs annually to customers. WEIM and WEIS cost benefits are driven by: (1) net market revenues from real-time energy sales to other market entities and, (2) lower cost when the market can serve load at a lower cost than energy produced from the generation fleet. Participating in WEIM, however, would bring up to three times greater gross benefits to customers than participating in WEIS (see Table 03-4).

Scenario	WEIM Benefits (Annual)	WEIS Benefits (Annual)
2019 Historical Benchmark	$10.3–$12.9 million	$3.2–$4.0 million
2025 Future Base	$11.6–$14.3 million	$4.3–$5.3 million

Table 03-4. WEIM and WEIS Participation Financial Benefits Summary

WEIM has a much broader geographic footprint that reflects greater load and resource diversity, as well as the arbitrage potential caused by time zone differences across its participants. WEIM also has higher renewable penetration, whose variability can create greater real-time purchase or sale opportunities at attractive energy prices.

The BA study performed by NAES and the market study performed by E3 both indicate potential customer savings could be created by transitioning from the WAPA BA to the PacifiCorp East BA and joining the CAISO WEIM. Based on these results, Cheyenne Light and Black Hills Power continue to investigate the changes required to unlock the customer benefits of transitioning BAs and joining the CAISO WEIM.

The Role of Transmission to Capture Customer Benefits

The potential for customer benefit from wholesale real-time markets is clear, however, challenges exist for maximizing those opportunities. The BA for both the CAISO WEIM and the SPP WEIS determines which real-time energy market to join. This is primarily a result of energy imbalance being an ancillary service provided by BAs that real-time energy markets replace.

Realizing the relatively higher market benefits of the CAISO WEIM would require Cheyenne Light and Black Hills Power to transition to a BA that is, or will be, participating in the WEIM. Both BAs that neighbor WAPA, PacifiCorp and Public Service Company of Colorado (PSCO), either are or will be WEIM participants.

There are challenges to moving to either of these BAs, particularly for Cheyenne Light. The utility currently takes service from the WAPA Loveland Area Project (WAPA-LAP) to deliver energy to its customers from both owned and contracted resources and market purchases. This type of transmission service is used to deliver energy to load and cannot be used to move energy off-system. Even if WAPA agreed to allow a change of BAs through its network transmission service, Cheyenne Light's benefits would be limited unless transmission service to move generation (such as excess wind or economic gas generation) to the other WEIM market participants is purchased and available.

As an alternative, Cheyenne Light could construct transmission to a WEIM-participating BA to capture WEIM benefits for its customers. Beyond providing a clear path to the WEIM market, adding transmission also increases the transfer capability to move energy more efficiently between the two utilities. Transmission expansion could deliver long-term net customer benefits, particularly if there are other costs that new transmission could offset beyond energy cost savings that can reasonably be expected from the WEIM.

04. INTEGRATED RESOURCE PLANNING PROCESS

Black Hills Energy has developed one IRP by simultaneously analyzing three paths employing the same modeling and analysis process, albeit with different assumptions. The three analysis paths are for:

- Cheyenne Light (individually)
- Black Hills Power (individually)
- Cheyenne Light and Black Hills Power (jointly)

Nine scenarios were analyzed for each path. Candidate resource portfolios were developed and a least-cost resource portfolio was identified for each analysis path. From that, a preferred resource plan was selected for Cheyenne Light and Black Hills Power.

THE INTEGRATED RESOURCE PLANNING PROCESS

The IRP is a twenty-year plan that meets forecasted annual peak resource requirements (plus an established reserve margin) through a combination of economically priced thermal and renewable resources and energy efficiency measures, while maintaining system flexibility and complying with environmental laws and regulations.

To develop the IRP, the utilities:

- Forecasted future loads against current resources.
- Modeled and analyzed potential resource portfolios using an array of assumptions.
- Identified potential resource options to meet future loads.

- Determined the preferred resource mix to prudently balance cost and risk.
- Selected a preferred portfolio that meets forecasted needs.

The IRP Process Flowchart

Figure 04-1 details the IRP process in a flowchart.

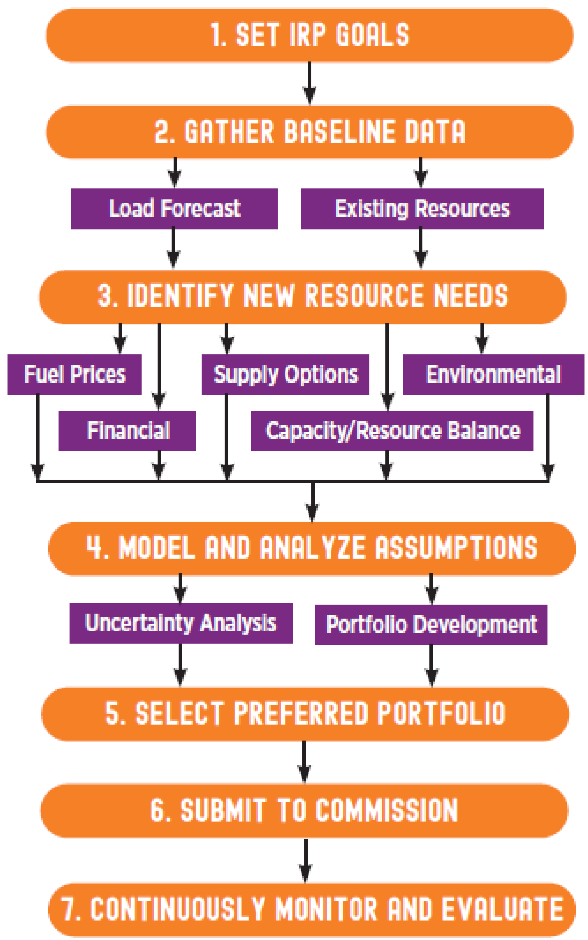


Figure 04-1. IRP Process Flowchart

The IRP process employed analytical tools that fairly evaluated and compared the costs and benefits of resource options to achieve lower overall costs. In addition, the process relied upon the following studies specifically conducted for the development of this IRP:

- Busbar Cost Study (Appendix D)
- Three Neil Simpson Unit II Power Plan Studies: natural gas conversion, life assessment, and decommissioning (Appendix E)
- Variable Energy Resource Integration Report (Appendix F)
- Balancing Authority Feasibility Study (Appendix G)
- Energy Market Participations Analysis (Appendix I)

- Overview of Forecasting Models (Appendix L)

The IRP developed numerous scenarios. These scenarios considered reserves and reliability, load forecasts, existing resources, fuel prices (coal, natural gas, and market), supply options (thermal, renewable, and battery storage), capacity and resource balance, environmental costs, and financial assumptions. Common risks and uncertainties were addressed through sensitivity analysis.

IRP PROCESS GUIDELINES

Wyoming Commission Guidelines

The Wyoming *Commission Guidelines Regarding Electric IRP* sets forth ten guidelines for the development of an IRP filed with the Commission. The following are the Wyoming Commission guidelines followed by an explanation of how Cheyenne Light and Black Hills Power followed such guidance in the development of the IRP:

A. The public comment process employed as part of the formulation of the utility's IRP, including a description, timing, and weight given to the public process.

A publicly noticed Wyoming Commission meeting was held on June 10, 2021 to discuss the IRP with stakeholders. See Stakeholder Process on page 04-4.

B. The utility's strategic goals and resource planning goals and preferred resource portfolio.

The Cheyenne Light and Black Hills Power preferred plans are developed to address resource needs during the near-term planning period. These plans are developed based on the results of the load and resource balance, capacity expansion, production cost modeling, and risk analysis. This information is considered individually and as a whole to make an informed recommendation that balances customer cost and risk. See The Selected Preferred Plans on page 08-27.

C. The utility's illustration of resource need over the near-term and long-term planning periods.

The IRP process is based on a near-term need planning period of six years and a long-term planning period of 20 years. Analysis is based on forecasted load, projected load growth, and the existing resource portfolio to serve the load. See Load and Resource Balance on page 08-1.

D. A study detailing the types of resources considered.

Cheyenne Light and Black Hills Power engaged Black & Veatch to perform a busbar study of candidate resource options. The busbar study analyzed 35 candidate resource options. Detailed technology costs and performance characteristics from the busbar study were used analysis to determine preferred resource portfolios. See Candidate Resource Options on page 05-11.

E. Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP.

The IRP includes a detailed discussion of any changes in expectations in resource acquisitions. See Comparison to Previous IRPs on page 08-28.

F. The environmental impacts considered.

Impacts considered included but were not limited to:

- Carbon dioxide (CO_2) estimates (such as carbon cost descriptions) and their justification. See Emissions Costs on page 07-26.
- The CLEAN Futures Act Scenario highlights potential impacts to customers. See CLEAN Future Act on page 08-25.
- Alignment with the Black Hills Corporation stated GHG goals.

G. Market purchases evaluation.

The IRP studies the optimum level and amount of market purchases, compares market purchases against the candidate resources over a range of scenarios. See Scenario Analysis on page 08-9.

H. Reserve Margin analysis.

The 15 percent planning reserve margin considers tradeoffs, reliability, and the risks and costs of planning reserves. See Planning Reserve Margin on page 04-6.

I. Demand-side management (DSM) and conservation options.

Modeled impacts include currently offered DSM programs and resultant savings. See Demand-Side Management on page 07-7.

Stakeholder Process

Cheyenne Light and Black Hills Power held two meetings with the Wyoming Commission Staff and the Wyoming Office of Consumer Advocate (OCA) to discuss various aspects of the development of the IRP on October 8, 2020 and March 8, 2021. In addition, a publicly noticed stakeholder meeting was held at the Wyoming Commission on June 10, 2021.

PLANNING PERIOD AND NEAR-TERM NEED PLANNING PERIOD

A planning period must be sufficiently long to incorporate the operating life expectancies of both thermal and renewable resources. The IRP is based on a long-term planning period of 2021 through 2040.

A near-term need planning period must provide for adequate time to acquire the necessary resources to meet customers' electricity needs. The IRP is based on a six-year near-term need planning period, addressing the years 2021–2026, which includes the years in which the IRP identified additional resources to meet Black Hills Power's capacity needs.

STRATEGIC DECISIONS AND GOALS

The goal of the IRP is to develop a portfolio that minimizes cost to customers while mitigating customer risk, achieves generation and transmission adequacy, continues to deliver safe, reliable energy, meets environmental objectives, and meets regulatory requirements.

This IRP creates a roadmap for designing and implementing a long-term strategy for shaping a robust generation mix. The process incorporates multiple external forces,[20] considers wide ranging future possibilities and their uncertainty, accounts for business goals, and most importantly, focuses on the energy needs of customers.

The IRP informs decisions on procuring resources; it creates an analytical tool for assessing investments in various resources in both the short- and long-term to better meet the ever-changing technological developments and evolving energy needs and preferences.

Through the IRP process, the IRP team developed about three dozen candidate resource options.[21] The team modeled and analyzed each candidate resource option against a wide range of scenarios and sensitivities to select preferred portfolios for Cheyenne Light and Black Hills Power. The preferred portfolios continue to modernize the power grid to maintain the high level of reliability customers enjoy.

MODELING SCENARIOS

Modeling and analyzing potential resource portfolio scenarios is a fundamental process in the development of an IRP. Modeling scenarios are based on the variables that would create the largest impact on cost variability and risk. These variables include forecasted load, natural gas, economy energy prices, and environmental policy.

Among the array of potential options, the IRP modeled the following scenarios:[22]

Base Scenario. Uses median levels for all input assumptions including load and fuel price forecasts.

Environmental Scenario. Uses HAPG's environmental market energy price and carbon tax forecasts.

Low Natural Gas Scenario. Uses HAPG's low natural gas and market energy price forecasts.

High Natural Gas Scenario. Uses HAPG's high natural gas and market energy price forecast.

Low Load Scenario. With load growth reduced from the base scenario.

High Load Scenario. With load growth increased over the base scenario.

20 Described in Chapter 3. Integrated Resource Planning Environment.

21 See Chapter 5. Generation Resources for a description of each candidate resource portfolio.

22 The analysis of these scenarios is described in detail in Chapter 8: Portfolio Analysis and Selection.

High-High Load Scenario. With a 25 MW step-load added to the high load scenario.

Battery Energy Storage System (BESS) Scenario. Uses Black & Veatch's estimated costs to install and operate 10 MW of four-hour battery storage for each utility.

Carbon Capture Scenario. Uses Black & Veatch's estimated cost to install and operate carbon capture technology on an existing coal generation unit.

The analysis of the scenarios are described in detail in Chapter 8: Portfolio Analysis and Selection.

MODELING INPUTS AND ASSUMPTIONS

Assumptions

Many key data assumptions form the inputs required to model and analyze the various candidate resource options—and directly affect outcomes. The assumptions include planning reserve margin, load forecast, existing resources, fuel prices, supply options, capacity and resource balance, environmental costs and constraints, and financial considerations.

The Base Case options contained median forecasts for all assumptions. Specific subsets of those assumptions were varied in the Environmental, Low Gas, High Gas, Low Load, High Load, and High-High Load scenarios to test the risk associated with each specific assumption.

Planning Reserve Margin

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

WECC identified an annual planning reserve margin of 15 percent as being a sufficient resource adequacy threshold for the region in its Western Assessment of Resource Adequacy Report filed December 18, 2020. Consistent with the WECC report, the IRP process employed a 15 percent planning reserve margin. In addition, Cheyenne Light and Black Hills Power have historically used a 15 percent planning reserve margin.

Load Forecast

In large part, annual peak and energy load forecast determines the quantity and type of resources needed to meet future demand. Based on assumptions about local population changes and local economic factors, it is the starting point for resource planning.

The IRP employs an econometric forecasting methodology to forecast retail peak demand and energy from different types of data: historical load, revenue, economics, and weather data. These datasets were used to develop monthly system-level peak demand forecast and the major customer class energy forecasts. The IRP developed base, low, high, and high-high load forecasts, and includes system-level demand and major customer class energy forecasts using historical data.

Cheyenne Light's final system-level peak demand and energy forecasts exclude all LPCS loads and BCIS loads.

Wholesale Contracts

Black Hills Power participates in wholesale energy and capacity transactions. Transactions with a term of a year or greater are added to the retail load forecast to determine the total load to be served. Currently, Black Hills Power has contracts to serve portions of the energy and capacity requirements of Municipal Energy Agency of Nebraska (MEAN), Montana-Dakota Utilities (MDU), and the City of Gillette.

Existing Resources

The IRP examined the technology, size, age, and potential retirement dates of all existing resources.[23]

Fuel Price Forecasts

Fuel prices can shift as a result of demand growth, climate legislation, export infrastructure, and supply conditions. Thus, the IRP employed reasonable, recent, and consistent projections of fuel prices in the modeling and analysis.

The IRP used assumptions based on the HAPG WECC 2020 Fall Reference Case for all fuel price forecasts.[24]

Natural Gas Price Forecasts

The IRP incorporated a forecast for both existing and future natural gas-fired resources. Basis differential and transportation costs were added to the forecast to reflect the delivered price of natural gas. HAPG provided base, low, and high forecasts from the Fall 2020 Power

23 See Chapter 5: Generation Resources for a complete discussion and description of the existing fleet.

24 See Appendix H: Price and Cost Forecasts for the schedules of all fuel price forecasts.

Reference Case. IRP modeling was also based on a low gas price scenario, a high gas price scenario, and a reference case scenario.

Coal Price Forecasts

The IRP incorporated an internally developed coal price forecast. The coal price reflects the benefits of the coal plants being located adjacent to the coal mine, which essentially eliminates coal transportation and storage costs.

Coal costs apply to all coal-fired units.

Diesel Price Forecasts

HAPG provided a base forecast for the existing Ben French diesel-fired resources.

Economy Energy Prices

Economy energy is energy (purchased without capacity) that is available in the market from time-to-time for a price that is lower than the incremental cost of generation from a utility's own resources. Economy energy is not firm energy and, therefore, is only available if a utility has adequate capacity to support load requirements. As the selling party can recall an economy energy transaction at any time, the buying utility must maintain sufficient contingency reserve to replace any recalled supply.

The IRP reflects a certain amount of economy energy purchases based on past transactions that are likely to continue, at least in the near-term.

Seasonal Firm Market Purchase Prices

The IRP uses seasonal firm market purchases with pricing based on the Palo Verde, Arizona economy energy forecast, plus a 20 percent premium. Seasonal firm market purchases are blocks of energy that are available for purchase with firm transmission.[25]

Supply Options

The IRP considered a full range of supply alternatives, making reasonable assumptions about cost, performance, availability, and capacity. Modeling included uncertainties around construction (availability and cost of raw materials and skilled labor, construction schedules, and future regulations) as well as the feasibility of emerging technologies.

Resources considered included coal and natural gas thermal resources, wind and solar renewable generation, simple cycle and combined cycle CTs, small modular reactors, and battery storage.[26]

25 See Chapter 5: Generation Resources and Chapter 7: Modeling Approach and Assumptions for additional details.

26 These supply options are discussed in detail in Chapter 5: Generation Resources.

Demand-Side Management

DSM presents opportunities for energy conservation and efficiency, saving fuel and reducing environmental impacts. DSM can decrease costs by reducing the amount of capacity and energy required from the most expensive resources to meet system peak demand. In addition, DSM can mitigate a variety of risks: impending carbon legislation, environmental regulations affecting air and water quality, and the deferral of transmission and distribution investments.

In 2018, Cheyenne Light filed to renew its tri-annual DSM plan for the years 2019–2021 (originally approved for 2016–2018). The renewal plan is composed of the same two broad categories as the previous plan: residential and non-residential (commercial and industrial) programs. Each program addresses the needs of various customers.

The residential programs include heating and cooling, appliances and electronics, high-efficiency lighting, energy evaluations, thermal envelope, new construction, and includes a Low-Income Weatherization program. The non-residential programs include commercial prescriptive, custom, and small business direct install.

The 2019–2021 DSM plan resulted in demand reductions and energy savings. The IRP incorporated these actual (imbedded in historical load amounts) and projected reductions in its modeling.

The anticipated 2022–2024 DSM Plan was not finalized at the time of the analysis for this IRP, therefore, the potential reductions were not incorporated into the load forecast.

The 2017–2019 Black Hills Power South Dakota DSM plan resulted in demand reductions and energy savings. The IRP incorporated these actual (imbedded in historical load amounts) and projected reductions in its modeling. Black Hills Power does not have a DSM Program in Wyoming and Montana.

On September 1, 2020, Black Hills Power discontinued its South Dakota DSM program due to the inability to establish a portfolio of energy efficiency offerings that are and will remain cost-effective.

Environmental Costs and Constraints

While there is currently no national goal for GHG emission reduction or other similar emissions requirement on generation resources, the possibility for such legislation remains.

On January 19, 2021, the District of Columbia Circuit Court vacated the Affordable Clean Energy rule as "legally flawed" and remanded it to the EPA for further proceedings. According to the EPA, this ruling obviates the need for any state to submit a related environmental compliance plan. The current administration intends to pursue action on addressing climate change as evidenced by the country rejoining the Paris Climate Agreement, the largest international effort to curb global warming.

Further, Congress is considering legislation aimed at reducing GHG emissions, including the CLEAN Future Act. The proposed legislation would set regulatory standards in the power, transportation, buildings, and industrial sectors to address climate change and authorize spending over the next ten years to enable deep decarbonization.

The IRP uses the HAPG WECC 2020 Fall Reference Case to forecast CO_2 emission costs in its environmental and CLEAN Future scenarios. These forecasted emission costs and associated environmental market prices are used to determine the portfolio necessary to comply with potential future or pending environmental legislation.[27]

Financial Assumptions

The IRP modeling relied on numerous financial assumptions, to develop the incremental cost of debt and equity, return on rate base, and interest rate assumptions necessary to calculate the total system present value revenue requirement for each candidate resource portfolio and scenario.

Modeled financial assumptions include the cost of debt (or interest rate), cost of equity, weighted average cost of capital after taxes, income tax rate, inflation rate, the capital structure of debt and equity, property tax rate, and an annual construction escalation rate. Assumptions specifically related to resources include a five-year fixed charge tax rate for wind and solar resources and a 30-year fixed charge rate for simple cycle CTs, combined cycle CTs, peaking resources, fuel conversions, new wind and solar, battery storage, and a Neil Simpson Unit II life extension.

The Wyoming Commission approved the cost of debt, cost of equity, and capital structure percentages in Cheyenne Light's most recent rate case (Docket No. 20003-132-ER-13).

The South Dakota Commission and Black Hills Power reached a global settlement in the last rate review (Docket No. EL 14-026). Specific inputs for cost of debt and cost of equity were not stated in public orders. Capital structure percentages were stated in public orders and the IRP incorporates those values.

INTEGRATED RESOURCE ANALYSIS

The IRP process employed industry-accepted analysis methods to develop three main analyses paths: one each for Cheyenne Light, for Black Hills Power, and one joint.

HAPG was retained to provide analytical services in support of the IRP. HAPG used its Capacity Expansion and Portfolio Optimization modules in its deterministic modeling and its Strategic Planning *powered by MIDAS Gold®* module to model the financial and risk simulations.[28]

27 See Chapter 7 for additional descriptions and analysis of the environmental and CLEAN Future scenarios.

28 See Appendix N for HAPG's IRP Modeling Summary.

The IRP process undertook capacity expansion and production cost modeling to determine the portfolio of future resources that meets the needs of customers over the planning period in the least-cost manner. Subsequent to those analyses, the IRP process analyzed several scenarios and their associated risk factors.

Load and Resource Balance

Load and resource balances compare the capacity of available resources to the peak resource requirements, plus planning reserves, on an annual basis over the planning period. The load and resource balances highlight the years in which forecasted demand exceeds resources, thus indicating a need for additional capacity.

Capacity Expansion Modeling

Capacity expansion produces unique resource portfolios across a range of different planning assumptions. Capacity expansion minimizes operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints, and optimizes resource additions by resource costs and capacity constraints (peak resource requirements plus a planning reserve margin).

Capacity expansion modeling is an industry-accepted process used to determine the appropriate type, size, and timing for economic resource addition. A 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 present value revenue requirement (PVRR) subject to meeting load plus reserves.

Production Cost and Financial Modeling

HAPG's Portfolio Optimizer software analyzes, estimates, and reports the optimal dispatch of a generation portfolio, and includes a stochastic model to simulate volatility in electricity, fuel prices, and loads.

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 load every hour, then economically serves that load with the available resources, and captures the associated cost.

The Strategic Planning module measures and analyzes consumer value. The Financial module models aspects regarding costs external to the operation of units and other valuable financial information. The Risk module performs stochastic analyses on all other modules.

Performing Uncertainty Analysis

The IRP process modeled and analyzed a number of test cases and scenarios on 35 candidate resource options, against a wide array of input assumptions representing significant sources of plan cost variability and risk, to assess the sensitivity of results to changes in input uncertainties. These inputs include the load forecast, the price of natural gas, and potential enactment of carbon tax, limitation on carbon emissions, or other similar mechanisms.

The testing assessed single-factor and multifactor sensitivities and employed probabilistic techniques and stochastic modeling. The modeling process was performed in a transparent and logical manner without undue intervention.

Among the array of options, the following specific scenarios and sensitivities were modeled: load, natural gas prices, market prices, environmental policy, and resource technology.

Stochastic Analysis

Utilities must plan for the future electricity needs of customers in an environment of significant uncertainty. The analysis conducted for the IRP examined resource needs under a variety of possible future conditions. Stochastic analysis and risk profile compilation were among the risk techniques examined.

The stochastic analysis conducted by HAPG examined a wide range of uncertainties that resulted in 50 unique "future" scenarios for price determination and evaluation of a given portfolio of resources. The scenarios are driven by variations in modeling inputs and assumptions (for example, peak demand and energy forecast, economy energy price, natural gas price, coal price, and capital costs) and consider statistical distributions, correlations, and volatilities. Cumulative probability distributions (also known as risk profiles) were used to visually assess the results of the stochastic analysis.

Selecting the Preferred Portfolio

Preferred portfolios are developed to address resource needs during the near-term need planning period. Resource needs beyond the near-term planning period will be addressed in future IRPs. The Cheyenne Light and Black Hills Power preferred portfolios were developed based on the results of extensive modeling and analysis. This information was considered individually and as a whole to make an informed recommendation that balances customer cost and risk. From that, preferred resource plans were selected for Cheyenne Light and Black Hills Power.

05. GENERATION RESOURCES

The Cheyenne Light and Black Hills Power resource mix includes firm generation fired by diesel fuel, natural gas and coal, and renewable generation from wind and solar. Candidate resource options considered by the IRP modeling encompasses firm generation from simple cycle and combined cycle combustion turbines; renewable generation from wind, solar, and battery storage; retrofitting existing resource including the possible addition of carbon capture technology; and seasonal firm market purchases.

CURRENT GENERATION SUPPLY RESOURCES

Cheyenne Light and Black Hills Power serve their customers through a combination of owned generation and power purchase agreements. These resources are fueled by coal, natural gas, diesel oil, wind, and starting in 2022, solar.

A vertically integrated generation portfolio enables the utilities to better deliver safe, reliable, and cost-effective energy. This resource strategy protects customers from energy market volatility by constructing, owning, and operating generation assets.

Cheyenne Light Generation Mix

The generation mix of Cheyenne Light consists of owned and co-owned generation and PPAs for firm and renewable sources.

Resource	Fuel	MW	Owner	Location	Start	End/ Retire
Cheyenne Prairie SCCT	Natural Gas	37	Cheyenne Light 100%	Cheyenne	2014	2054
Cheyenne Prairie CCCT	Natural Gas	40	Cheyenne Light 42% (Black Hills Power 58%)	Cheyenne	2014	2054
Wygen II	Coal	90	Cheyenne Light 100%	Gillette Energy Complex	2008	2048
Corriedale	Wind	20	Cheyenne Light 38% (Black Hills Power 62%)	Cheyenne	2020	2045
Wygen I PPA*	Coal	60	Black Hills Wyoming	Gillette Energy Complex	2001	2032
Happy Jack PPA	Wind	15	Duke Energy Generation Services	Cheyenne	2008	2028
Silver Sage PPA	Wind	10	Duke Energy Generation Services	Cheyenne	2009	2029
Total		272				

* Cheyenne Light has executed three consecutive PPAs with Wygen I: 2001–2013; 2013–2022; and 2023–2032.

Table 05-1. Cheyenne Light Total Generation Mix

Currently, Cheyenne Light utilizes generating resources capable of producing 187 MW and has PPAs for another 85 MW of power for its customers. The IRP assumes all existing PPAs are not renewed or extended beyond their current expiration dates.

Black Hills Power Generation Mix

The generation mix of Black Hills Power is similar to Cheyenne Light, except more extensive. It consists of owned and co-owned generation and PPAs for both firm and renewable sources.

Resource	Fuel	MW	Owner	Location	Start	End/ Retire
Ben French Diesels #1–5	Diesel	10.0	Black Hills Power 100%	Rapid City	1965	–
Ben French SCCTs #1–4	Natural Gas/ Diesel	80.0	Black Hills Power 100%	Rapid City	#1: 1977 #2: 1977 #3: 1978 #4: 1979	–
Lange SCCT	Natural Gas	39.0	Black Hills Power 100%	Rapid City	2002	–
Neil Simpson SCCT	Natural Gas	39.0	Black Hills Power 100%	Gillette Energy Complex	2000	–
Neil Simpson II	Coal	80.0	Black Hills Power 100%	Gillette Energy Complex	1995	–
Cheyenne Prairie CCCT	Natural Gas	55.0	Black Hills Power 58% (Cheyenne Light 42%)	Cheyenne	2014	2054
Corriedale	Wind	32.5	Black Hills Power 62% (Cheyenne Light 38%)	Cheyenne	2020	2045
Wygen III	Coal	52.0	Black Hills Power 52% (MDU 25%; Gillette 23%)	Gillette Energy Complex	2010	–
Wyodak	Coal	67.0	Black Hills Power 20% (PacifiCorp 80%)	Gillette Energy Complex	1978	2039
Colstrip PPA	Coal	50.0	PacifiCorp	Colstrip, Montana	1997	2023
Happy Jack PPA	Wind	15.0	Duke Energy Generation Services	Cheyenne	2008	2028
Silver Sage PPA	Wind	20.0	Duke Energy Generation Services	Cheyenne	2009	2029
Wind PPA	Wind	12.0	Platte River Power Authority (PRPA)	Cheyenne	2018	2029
Fall River PPA[29]	Solar	80.0	Fall River Solar	Fall River County, South Dakota	2022	2043
Total		626.5				

Table 05-2. Black Hills Power Total Generation Mix

Currently, Black Hills Power utilizes generating resources capable of producing 449.5 MW and has PPAs for another 177 MW. Black Hills Power is contracted for 80 MW of solar generation through a 20-year PPA in 2022. The IRP assumes that all existing PPAs are not renewed or extended beyond their current expiration dates.

Gillette Energy Complex

A number of generation stations are sited at the Gillette Energy Complex: Wygen I, Wygen II, Wygen III, Wyodak, Neil Simpson II, and the Neil Simpson simple cycle CT. The Wyodak mine

29 The Fall River PPA is scheduled to begin on December 31, 2022.

is part of the complex. The supply coal mine located adjacent to the coal-fired plants eliminates high fuel transportation costs. Together, these units generate 827 MW of power.

Figure 05-1. Gillette Energy Complex

Cheyenne Light Owned Supply-Side Resources and Power Purchase Agreements

Cheyenne Prairie Simple Cycle CT

The Cheyenne Prairie Generating Station (CPGS), located in Cheyenne, consists of two CT units. The plant was commissioned on October 1, 2104. Cheyenne Light owns one CT: a 37 MW simple cycle unit.

Figure 05-2. Cheyenne Prairie Generating Station Simple Cycle CT

Wygen II

The Wygen II coal-fired steam generator began operation on January 1, 2008. The 90 MW plant is located in the Gillette Energy Complex. The power plant, wholly owned by Cheyenne Light, obtains all its fuel from the adjacent Wyodak coal mine, which keeps fuel costs low.

Wygen I

The Wygen I coal-fired power plant has a total capacity of 90 MW. It was first commissioned in 2008. The plant is located in the Gillette Energy Complex and obtains all its fuel from the adjacent Wyodak coal mine. Black Hills Wyoming (an affiliate of Cheyenne Light and Black

Hills Power) owns 76.5 percent of the facility; Municipal Energy Agency of Nebraska's (MEAN), owns the remaining 23.5 percent.

On August 2, 2020, FERC approved an extension of the PPA for another 10 years through December 31, 2032, with updated pricing beginning on January 1, 2022. The IRP models Wygen I as supplying 60 MW to Cheyenne Light through 2032.

Black Hills Power Owned Supply-Side Resources and Power Purchase Agreements

Ben French Diesels #1–5

The five Ben French diesel units were commissioned on November 25, 1965. They are the oldest units in the Black Hills Power generation mix. Each unit has a rated capacity of 2 MW, for a total of 10 MW. The facility is located in Rapid City and is wholly owned by Black Hills Power.

Figure 05-3. Ben French Diesel Generators

Ben French Simple Cycle CTs #1–4

The four Ben French General Electric LM6000 simple cycle CTs were installed over a period of approximately two years. Units #1 and #2 were commissioned on August 1, 1977; unit #3 was commissioned on June 27, 1978, and unit #4 was commissioned on June 28. 1979. Each CT runs on natural gas and diesel fuel. Each unit has a rated capacity of 20 MW for a total facility capacity of 80 MW. The facility is located in Rapid City and is wholly owned by Black Hills Power.

Figure 05-4. Ben French Simple Cycle CTs

Lange Simple Cycle CT

Lange is a 39 MW GE LM6000 simple-cycle, gas-fired CT wholly owned by Black Hills Power. It is located in Rapid City and was commissioned on March 10, 2002.

Figure 05-5. Lange Simple Cycle CT

Neil Simpson Simple Cycle CT

Neil Simpson is a 39 MW GE LM6000 simple-cycle, gas-fired CT owned by Black Hills Power and located in the Gillette Energy Complex. It was commissioned on June 19, 2000.

Neil Simpson Unit II

Neil Simpson Unit II is a coal-fired steam power plant with a total capacity of 80 MW owned by Black Hills Power. Commissioned on September 5, 1995, the plant is located in the Gillette

Energy Complex. The plant obtains its fuel from the adjacent Wyodak coal mine, which keeps fuel costs low.

Wygen III

Wygen III is a coal-fired steam generator with 110 MW of total capacity. It was commissioned on April 1, 2010. It is located in the Gillette Energy Complex and obtains its fuel from the adjacent Wyodak coal mine. Black Hills Power owns 52 percent of the plant, Montana-Dakota Utilities (MDU) owns 25 percent, and the City of Gillette owns 23 percent. The power plant delivers 52 MW of energy to Black Hills Power customers.

Figure 05-6. Wygen II and Wygen III Generation Facility

Wyodak

The Wyodak coal-fired generating facility has a total capacity of 362 MW. It was commissioned on June 1, 1978 and is jointly owned by PacifiCorp (80 percent) and Black Hills Power (20 percent). PacifiCorp operates the facility. It is located in the Gillette Energy Complex and obtains all its fuel from the adjacent Wyodak coal mine. The power plant delivers 67 MW of energy to Black Hills Power customers.

Figure 05-7. Wyodak Generation Facility

Colstrip PPA

Black Hills Power entered into the Colstrip PPA with PacifiCorp for 50 MW of coal generation in 1997. Power is generated by the four-unit 2,100 MW Colstrip power plant located in Colstrip, Montana. The adjacent Rosebud surface mine supplies all the fuel to the power plant, which keeps fuel costs low. This PPA expires on December 31, 2023.

Fall River Solar PPA

Black Hills Power entered into a PPA with Fall River Solar for 80 MW of photovoltaic solar generation scheduled to begin in late 2022. The PPA will add to an increasing portfolio of renewable generation, will continue to diversify the generation mix, and will contribute to the reduction of GHG emission intensity. The Fall River Solar plant, owned by Greenbacker Renewable Energy, is located in Fall River County, south of Rapid City.

Jointly Owned Supply-Side Resources and Power Purchase Agreements

Cheyenne Prairie Combined Cycle CT

On October 1, 2014, Cheyenne Light and Black Hills Power completed construction and commissioned CPGS, located in Cheyenne. The combined capacity of this natural gas fired generating station is 132 MW, and supplies power to customers of both utilities.

The facility consists of a 37 MW simple cycle CT and a 95 MW combined cycle CT. Cheyenne Light owns 42 percent of the combined cycle unit (40 MW) and Black Hills Power owns the remaining 58 percent (55 MW).

Figure 05-8. Cheyenne Prairie Generating Station Combined Cycle CT

Corriedale Wind Facility

On November 30, 2020, the Corriedale wind facility was completed and placed into service; it is jointly owned by Cheyenne Light and Black Hills Power. The 52.5 MW facility delivers renewable energy to large commercial, industrial, and governmental customers enrolled in the fully subscribed Renewable Ready program.

The facility, located north and south of Interstate 80 west of Cheyenne, consists of twenty-one 2.5 MW wind turbines. Cheyenne Light owns 38 percent (20 MW) and Black Hills Power owns the remaining 62 percent (32.5 MW).

Figure 05-9. Corriedale Wind Facility

Happy Jack Wind

The Happy Jack wind facility, wholly owned by Duke Energy Generation Services, is located in Cheyenne. Commissioned on September 3, 2008, the facility consists of fourteen 2.1 MW turbines for a maximum capacity of 30 MW. Cheyenne Light purchases all the facility's generation through a PPA expiring 20 years after the plant's inception, selling half of it to Black Hills Power.

Figure 05-10. Happy Jack Wind Facility

Silver Sage Wind

The Silver Sage wind facility, wholly owned by Duke Energy Generation Services, is located in Cheyenne. Commissioned on September 30, 2009, the facility consists of twenty 2.1 MW turbines for a maximum capacity of 42 MW.

Cheyenne Light purchases 30 MW of the facility's generation through a PPA expiring 20 years after the plant's inception. Cheyenne Light supplies 10 MW to its customers and sells the remaining 20 MW to Black Hills Power. Platte River Power Authority (PRPA) sells Silver Sage's remaining 12 MW to Black Hills Power through a separate PPA.

Market Purchases

The company's Generation Dispatch and Power Marketing (GDPM) department transacts the market purchases necessary to fulfill both Cheyenne Light's and Black Hills Power's obligations for managing and procuring energy. GDPM also secures market purchases for third-party utilities and large customers. These wholesale transactions are added to the retail sales contracts to determine the sales obligation to be served by Black Hills Power.

GDPM regularly transacts with multiple counterparties in a number of regions, including but not limited to, the Northwest, Southwest, Rockies, SPP, and Midcontinent Independent System Operator (MISO). GDPM manages long-term, seasonal firm, and economy market purchases for energy. The department continually reviews and adjusts purchasing strategy and energy mix to better exploit market conditions.

Wholesale Power Contract Sales

Black Hills Power participates in wholesale energy and capacity transactions with contracts to serve portions of the energy and capacity requirements of MEAN, MDU, and the City of Gillette.

MDU owns 25 MW of the Wygen III coal-fired power plant at the Gillette Energy Complex. When Wygen III reduces its power production or is offline, Black Hills Power provides MDU with 25 MW of capacity from owned generation facilities or market purchases. Black Hills Power provides MDU with up to 50 MW of capacity in excess of its Wygen III ownership. This contract expires December 31, 2023 however, the IRP modeling assumes a contract extension through 2028. In addition, Black Hills Power provides MDU with planning reserves.

Similar to the agreement with MDU, Black Hills Power provides the City of Gillette with up to its owned Wygen III capacity of 23 MW from Black Hills Power generation facilities or market purchases. Providing this power only occurs when Wygen III reduces its power production or is offline. Black Hills Power provides the City of Gillette with capacity in excess of owned and purchased capacity. This contract renews annually, however, the IRP modeling assumes the contract expires on December 31, 2022. Black Hills Power also provides the City of Gillette with planning reserves.

Black Hills Power supplies up to 15 MW of unit-contingent capacity to MEAN. Supplying this power is based on the availability of the Neil Simpson II and Wygen III plants. This contract expires on May 31, 2028.

CANDIDATE RESOURCE OPTIONS

Cheyenne Light and Black Hills Power engaged Black & Veatch to perform a busbar study of candidate resource options. The busbar study analyzed 35 candidate resource options. The study recommended the IRP model 26 specific candidate resource options and exclude nine others. The IRP modeled both fuel-fired and renewable resources and analyzed several resource characteristics such as capacity, capital cost, operating cost, and outage rates.[30]

Detailed descriptions of these candidate resource options follow.

Fuel-Fired Resources

The IRP considered generic simple cycle CTs and combined cycle CTs as supply-side resource options in its modeling.

Simple Cycle Combustion Turbines

SCCTs typically utilize natural gas or No. 2 fuel oil and are available in a wide variety of sizes and configurations. SCCTs are generally used for peaking and reserve purposes because of their relatively low capital costs, higher full-load heat rate, and higher cost of fuel when compared to conventional baseload capacity. Many SCCTs have the added benefit of providing quick-start and black-start capability in certain configurations.

Combined Cycle Combustion Turbine

In a CCCT facility, the hot exhaust gases from the combustion turbine pass through a heat recovery steam generator (HRSG). The steam generated by the HRSG is expanded through a steam turbine which, in turn, drives an additional generator. CCCTs typically utilize natural gas and are available in a wide variety of sizes and configurations.

30 All of the modeled candidate resource options—including the nine excluded options—are discussed in detail in Appendix D: Busbar Cost Study conducted by Black & Veatch.

Renewable Resources

Several variable renewable energy resources were considered in the IRP analysis. This type of energy is variable because its primary energy sources—wind and sun—cannot be precisely predicted.

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.

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.

Solar energy is generated from PV cells made of semiconductors (such as silicon). When light strikes the cell, a certain portion of it is absorbed within the semiconductor material. The energy of the absorbed light is transferred to the semiconductor. The energy knocks electrons loose, allowing them to flow freely. This flow of electrons is a current. By placing metal contacts on the top and bottom of the cell, this electric current can be drawn off. The most common solar cell material is crystalline silicon, but newer materials for making solar cells include thin-film materials.

There are three types of panels: fixed-tilt, single-axis, and dual-axis. Fixed-tilt panels are installed at a fixed tilt and orientation and remain stationery. Single-axis panels 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 IRP. They generate between 10–25 percent more energy that fixed-tilt systems. Dual-axis panels 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.

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. 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. Thus, wind is a variable, non-dispatchable energy source.

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, that 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 be used to shift load from on-peak to off-peak times. Providing power during peak demand times can alleviate strain on the power grid and reduce energy supply costs by avoiding purchasing expensive power and operating expensive generation. Adding load in low demand times can also alleviate strain on the power grid and reduce energy supply costs by more efficiently operating generation resources.

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 to relieving reliability deficiencies.

Retrofitting Existing Units

Converting Coal Plants to Natural Gas

Converting a coal plant to utilize natural gas requires replacing the existing coal-fired burners with new gas supply piping, metering, and regulation equipment, natural-gas fired startup burners and associated equipment, and electric high energy spark igniters. Studies indicate natural gas conversions maintain current net generation levels.

Converting a coal unit to natural gas has many benefits. Natural gas conversions reduce GHG emissions and eliminate many expenses: coal costs, coal handling equipment, coal firing equipment, precipitators, ash handling equipment, ash disposal, and circulating dry scrubber and associated equipment. This existing equipment would be removed from service, lowering auxiliary power consumption.

Burning natural gas produces little to no ash. Thus, a natural gas conversion would eliminate water usage and wastewater discharge treatment costs associated with ash handling as well as virtually eliminate cleaning the air heater washes, boiler washes, precipitator washes, and dust control washes associated with ash deposition and fouling.

Finally, because natural gas burns cleaner than coal, natural gas conversions act as a hedge against potential environmental emission-reduction regulations and legislation.

Black & Veatch's Coal to Natural Gas Conversion Evaluation provided the cost and unit performance impacts of the potential conversion of the Neil Simpson Unit II power plant. Incremental costs include installation of new gas supply piping, metering, and regulation and replacement of the existing coal-fired burners, natural gas-fired startup burners, and associated equipment. Reductions in costs are related to coal handling equipment, coal firing equipment, ash handling equipment and disposal, the circulating dry scrubber and associated equipment, and water usage and wastewater discharge treatment associated with ash handling. Because of the removal of coal and ash handling equipment, Black & Veatch forecasted lower auxiliary power consumption and the ability to maintain current net generation output when converted to natural gas.

Converting Combined Cycle CTs to Hydrogen Fuel

Converting a combined cycle CT to operate on hydrogen lowers emissions while maintaining dispatchable generation. Conversion requirements depend on the unit's configuration, the overall balance of plant, and the desired concentration of hydrogen fuel. In addition, hydrogen-fueled turbines might require changes to the fuel accessories, bottoming cycle components, and plant safety systems.

Converting Simple Cycle CTs to Combined Cycle CTs

Converting a simple cycle CT to a combined cycle CT creates additional capacity and flexible generation. An additional turbine and HRSG are added to the existing turbine. Candidate resource options modeled in the IRP include the use of both wet cooling and dry cooling. Dry cooling would consume less water.

Converting Ben French Diesels to Natural Gas

Converting diesel-fired generators to natural gas-fired reduces emissions while maintaining dispatchable generation. Conversions resemble a major overhaul and generally take between three and five months. The process involves disassembling the engine; installing pistons, valves, and other key components to fire natural gas; enhancing the engine cooling system; and installing a replacement ignition system.

Extending the Life of Coal Plants

The safe operation of coal power plants, typically designed with an operating expectancy of 30 years, can be extended with diligent operations and maintenance (O&M) procedures. Nominal maintenance with little capital investment to equipment upgrades and replacement usually results in deficient, unsafe, and unreliable operation after 30 years.

Power plant system equipment degrades at various levels during the service life. Equipment service life depends on three key factors—safety, efficiency, and reliability—and is directly affected by operating conditions, O&M practices, and obsolescence. Periodically refurbishing or replacing system equipment better ensures safe, reliable, and efficient operation until the end of useful life.

In its Life Assessment Report on Neil Simpson Unit II, Black & Veatch modeled the cost of investments needed to keep the power plant operating in reliable condition as a coal unit. Black & Veatch categorized forecasted incremental costs into the following categories: safety, environmental, reliability, and infrastructure. In addition, Black & Veatch recommended projects that allow coal-fired units to operate safely and reliably until 2039. These recommended projects are over and above those capital renewal and replacement projects already planned.

As an alternative to extending the life of Neil Simpson Unit II, Black & Veatch also developed a Decommissioning and Demolition report. Decommissioning assumes the coal plant would be retired. The report evaluated demolition and remediation of the existing facilities including demolition desktop cost estimates and permitting tables to support Black Hills Power's budgetary planning activities and development process.

Carbon Capture Addition to Existing Coal Plant

Carbon capture is the process of capturing CO_2 from the flue gas before it is released into the atmosphere. The technology can capture up to 90 percent of CO_2 released by burning fossil fuels in electricity generation. The amine process requires a significant heating source (typically steam) and additional auxiliary power and maintenance to operate the carbon capture equipment.

Post-combustion equipment can be retrofitted to existing power stations that were originally built without it. Depending on the exact configuration the equipment would include an absorber, stripper, rich/lean solvent heat exchanger, flue gas cooler, condensate pumps, condenser, dryer, and compressors. Operating the carbon capture system requires increased chemical consumables and waste disposal.

Carbon capture modeling assumes the cost of incorporating life extension and carbon capture technology on a coal unit. Carbon capture cost and unit performance impacts were developed as part of the busbar study performed by Black & Veatch and applied to Neil Simpson Unit II during the IRP modeling. Incremental carbon capture costs included the installation and operation of new carbon capture equipment. Unit performance impacts include a reduction in net generation output because of the auxiliary power consumed by the carbon capture equipment. No incremental costs, revenues or tax incentives associated with the compression, transportation, sale, use, or sequestrations of the capture CO_2 were included in the analysis because of high levels of uncertainty around actual costs and revenues.

Seasonal Firm Market Purchased Power

Cheyenne Light and Black Hills Power make seasonal firm market purchases from the Palo Verde, Arizona market area, typically at a premium of approximately 20 percent. The 20 percent premium is based on what is normally available to be delivered to the service territory in relation to the Palo Verde market. The utilities make these purchases instead of procuring additional resources and use the purchases to meet short-term capacity needs to better manage customer costs.

06. TRANSMISSION AND DISTRIBUTION

Transmitting power relies on two main types of structures: transmission towers and distribution poles equipped with transformers. Transmission towers efficiently carry high-voltage electricity over long distances to distribution substations. Substations step down high-voltage electricity to lower voltages. From there, distribution power lines deliver the electricity to local infrastructure, businesses, and homes.

The transmission functions of both Cheyenne Light and Black Hills Power are centrally managed. The central transmission group plans and manages the towers, poles, and power lines to ensure their continued reliability to safely deliver power to customers. This group also administers the interconnection and open access of this system with other regional systems.

THE TRANSMISSION AND DISTRIBUTION SYSTEM

Cheyenne Light and Black Hills Power invest in transmission and distribution maintenance, upgrades, and new construction to meet the needs of customers and maintain reliability throughout their systems. Cheyenne Light and Black Hills Power own electric transmission systems with both high voltage and low voltage transmission lines.

A key strategic focus is to modernize utility infrastructure to meet customers' and communities' varied energy needs; ensure the continued delivery of safe, reliable and cost-effective energy; and reduce GHG emission intensity. In addition, Cheyenne Light and Black Hills Power invest in the accessibility, capacity, and integrity of their systems to meet customer growth.

Table 06-1 details the miles of transmission and distribution lines owned by Cheyenne Light and Black Hills Power.

Utility	State	Transmission (miles)	Distribution (miles)
Cheyenne Light	Wyoming	58	1,320
Black Hills Power*	South Dakota, Wyoming	1,242	2,565

* Black Hills Power owns 35 percent of a direct current transmission tie that interconnects the western and eastern transmission grids. The transmission grids are independently operated, and respectively serve the western and eastern portions of the United States.

Table 06-1. Transmission and Distribution Line Miles

Cheyenne Light and Black Hills Power rigorously comply with all applicable federal, state, and local regulations and strive to consistently meet industry best practice standards. Cheyenne Light and Black Hills Power employ a distribution integrity program to systematically and proactively repair and replace aging infrastructure in a timely manner to maintain a high level of reliability.

Cheyenne Light Transmission System

Cheyenne Light depends on both owned transmission and distribution lines as well as transmission systems operated by unaffiliated parties to deliver electricity to customers.

Cheyenne Light has an Open Access Transmission Tariff (OATT) on file with FERC that governs the rates, terms, and conditions for the wholesale use of the transmission system. Under the FERC OATT, Cheyenne Light is currently the only firm service customer on its own transmission system. There are no third-party transmission service customers on the Cheyenne Light transmission system. Because this transmission system is within the WAPA transmission system, no other import or export paths exist other than to and from WAPA.

Cheyenne Light is a network customer of the WAPA Loveland Area Project (WAPA-LAP) transmission system. WAPA-LAP's transmission system includes over 3,000 miles of transmission lines in Colorado, Nebraska, Wyoming, and Kansas. Cheyenne Light depends on its transmission service rights over the WAPA-LAP transmission system to deliver energy from its owned and contracted generating resources to WAPA-LAP, as well as deliver economy energy purchased on the wholesale market.

Black Hills Power Transmission System

Black Hills Power jointly operates a common use transmission system with Basin Electric Power Cooperative and Powder River Energy Corporation. The system is under FERC jurisdiction through a joint OATT which provides non-discriminatory access to the transmission facilities. Each participant owns their transmission assets and jointly operates the system for area energy transmission. The common use system also provides transmission service through a transmission tie.

Black Hills Power co-owns a 69 kV system with area utility cooperatives; use is governed by a transmission service agreement (TSA) among all owners. This system ownership contributes to low rates and high levels of reliability.

Transmission Tie

Black Hills Power owns 35 percent of a direct current transmission tie that interconnects the independently operated transmission grids serving the western and eastern United States. Basin Electric Power Cooperative owns the remaining 65 percent. This transmission tie provides transmission access to both the Western Electricity Coordinating Council (WECC) region in the west and the Mid-Continent Area Power Pool (MAPP) region in the east.

The transmission rights across the tie allows Black Hills Power to buy and sell energy in the eastern grid without isolating and physically reconnecting load or generation between the two transmission grids. The result is enhanced reliability of the system.

The transmission tie accommodates scheduling simultaneous transactions in both directions. This provides opportunities to sell excess generation or to make economic purchases that serve Black Hills Power's native load and contract obligations. It also enables Black Hills Power to take advantage of power price differentials between the two grids. The total transfer capacity of the tie is 400 MW: 200 MW from west to east and 200 MW from east to west.

Point-to-Point Transmission Access

Black Hills Power has firm point-to-point transmission access to deliver up to 50 MW of capacity and energy on PacifiCorp's transmission system. Access is governed by a TSA that expires December 31, 2023. Black Hills Power also has firm network transmission access to deliver power on PacifiCorp's system to Sheridan, Wyoming to serve a power sales contract with MDU.

REGULATORY REQUIREMENTS

Federal

Cheyenne Light and Black Hills power are subject to FERC oversight. The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale service; local, regional, and inter-regional transmission planning; and the transmission of electricity in interstate commerce. Cheyenne Light and Black Hills Power maintain tariffs and rate schedules governing rates, terms, and conditions for FERC-jurisdictional wholesale power and transmission services. The utilities also adhere to FERC's requirements for accounting, record-keeping, and reporting.

With FERC authorization, Cheyenne Light and Black Hills Power sell electric capacity and energy at market-based rates under filed tariffs and submit quarterly reports related to the transactions. Cheyenne Light and Black Hills Power own and operate FERC-jurisdictional interstate transmission facilities and provide open access transmission service under filed tariffs. FERC conducts routine audits regarding compliance with regulations.

Both utilities also comply with NERC reliability standards.

State

Cheyenne Light and Black Hills Power follow Wyoming state requirements by filing Certificates of Public Convenience and Necessity (CPCN) for approval of construction of projects for which notification is required by the Wyoming Commission.

Black Hills Power files a biennial 10-year energy facility plan with the South Dakota Commission. The plan describes existing and proposed generation and transmission facilities, including capacities; coordination efforts with regional agencies and other utilities, and efforts to minimize adverse effects of generation and load management.

TRANSMISSION AND DISTRIBUTION PLANNING

Cheyenne Light and Black Hills Power conduct comprehensive internal and regional transmission planning that is carefully coordinated with all local and regional transmission planners.[31]

Strategically Expanding Cheyenne Light's Transmission System

WAPA transmission costs to Cheyenne Light customers have steadily increased. As a result, Cheyenne Light is currently evaluating the feasibility of expanding its transmission system and associated facilities. This expansion would eliminate the need to purchase network transmission service from WAPA.

Cheyenne Light's load has been growing at a faster pace than the other transmission customer loads on the WAPA-LAP system. In 2020, Cheyenne Light represented approximately 17 percent of the WAPA-LAP transmission system load as compared to representing approximately 12 percent in 2010. WAPA allocates the transmission system annual revenue requirement to its transmission customers on a load-ratio share basis, resulting in Cheyenne Light being allocated an increasing share of WAPA costs.

Beyond the growth of Cheyenne Light's share of the annual WAPA transmission costs, the WAPA-LAP annual revenue requirement has grown steadily. From 2010 to 2021, the WAPA-LAP annual transmission revenue requirement increased from $47.6 million to $74.6 million. That increase represents a 3.8 percent compound annual growth rate, an overall 57 percent increase. The cumulative effect of the combined increase in the WAPA-LAP revenue requirement and Cheyenne Light's growing share equates to a 132 percent increase in WAPA-LAP transmission costs from 2010 to 2020.

The costs associated with an expansion of the Cheyenne Light system are being considered against current and future WAPA transmission costs. To date, the analysis indicates that long-term customer transmission costs will be lower through a utility-owned transmission expansion than WAPA-LAP system costs. This conclusion doesn't factor in any real-time market savings, nor does it consider incrementally greater customer market value if the owned transmission system is extended into Colorado to interface with the Public Service Company of Colorado (PSCO) Balancing Authority—both of which would only serve to increase customer benefit.

When this evaluation is completed, Cheyenne Light will seek Commission approval as necessary.

31 The transmission plans consider the entire region in which the utilities operate and the value of market access discussed in Chapter 3: Integrated Resource Planning Environment.

Local Transmission Planning

Cheyenne Light and Black Hills Power periodically plan the transmission and distribution system for each power grid. Planning tends to focus on meeting peak load conditions for each feeder and substation.

The utilities recognize the importance of stakeholder input to transmission planning. A stakeholder is any person, group, or entity that has an expressed interest in participating in the planning process, is affected by the transmission plan, or can provide meaningful input that might affect the final plan.

The Transmission Coordination and Planning Committee (TCPC) holds quarterly meetings as part of the annual study process under FERC Order No. 890 (outlined in the OATT attachment K). The utilities encourage stakeholders to attend and participate. The TCPC, an advisory committee of interested individuals or entities, provides input to the transmission plan and propose potential scenarios to study. Studies must meet NERC's TPL planning requirements for operational reliability "over a broad spectrum of system conditions and following a wide range of probable contingencies."[32] A range of operating conditions must be evaluated over the five to ten-year planning horizon.

The TCPC comprehensively evaluates the utilities' transmission systems together with surrounding transmission systems for critical scenarios. Cheyenne Light and Black Hills Power notify stakeholders at the start of a study and invite them to participate in planning meetings. At the request of the utilities, stakeholders provide relevant system modeling data and economic studies or alternative scenarios, as well as comment on the scope of any study.

Stakeholders can contact the TCPC at any point with questions and comments about the study process. The TCPC updates regional planning groups with progress reports to promote involvement from this larger stakeholder group.

The TCPC compiles the case studies and data, then outlines a project scope. Stakeholders review the preliminary study results and discuss potential solutions to any identified problems. This process allows the TCPC to develop a comprehensive transmission plan that meets the needs of all interested parties. A final stakeholder meeting is held as necessary to approve the study report and local transmission plan (LTP).

Regional Transmission Planning

Through WECC and WestConnect, Cheyenne Light and Black Hills Power participate in sub-regional and regional transmission planning.

WECC is the forum responsible for coordinating and promoting the reliability of bulk energy systems in the entire Western Interconnection. WECC includes committees that focus on transmission planning. One such committee, the Reliability Assessment Committee (RAC),

32 NERC Standard TPL-001-4 — Transmission System Planning Performance Requirements.

prepares economic models and performs high-level assessments of transmission congestion and expansion needs. RAC also assesses interconnection-wide reliability.

WestConnect is an association of transmission owners and other stakeholders in the WestConnect planning region. WestConnect plans regional transmission to comply with order No. 1000 through the WestConnect planning management committee. Individual transmission plans from the transmission owners are incorporated into the WestConnect regional planning process as appropriate, for review and public notice.

Transmission Line Siting Process

Cheyenne Light and Black Hills Power adhere to a five-step process for determining and constructing additional transmission lines.

1. **Identify the need.** When energy use rises and electrical demand approaches the limits of existing transmission systems, new facilities are needed before system usage is maximized to continue to provide safe, reliable energy to customers. With the change in transmission use due to variable energy resources and wholesale markets, the utilities also consider customer benefits associated with lower cost energy, upgrades to facilitate generator interconnections, and avoidance of high-cost transmission system rates.
2. **Identify route options.** The utilities analyze potential routes through the National Environmental Policy Act (NEPA) process. This process evaluates the environmental effects on federal land and determines alternatives.
3. **Garner public input.** Cheyenne Light and Black Hills Power often work with a variety of stakeholders, such as local officials, landowners, affected communities, and the public to gather input and comments depending upon the scope and stage of development. The process for siting transmission lines can be challenging, so the utilities carefully consider all public interactions to help determine a final line route.
4. **Select the final route.** After thoroughly analyzing community input and following the NEPA process, a final route is determined. Once selected, the utilities apply for all necessary permits and approvals from federal and state agencies as well as local jurisdictions.
5. **Begin construction.** Throughout the construction process, Cheyenne Light and Black Hills Power work directly with landowners to obtain rights-of-way on private lands and to minimize the impact building has on surrounding properties.

PRESERVING SAFETY AND RELIABILITY

Cheyenne Light and Black Hills Power have several key strategies and programs that reduce risk and improve reliability. Three major asset programs—vegetation management, line patrols, and pole inspections—enable the utilities to evaluate the condition of the electric infrastructure. The utilities partner with third-party consultants with broad industry experience to develop vital asset programs. This allows the utilities to proactively remediate aging or damaged assets.

The Cheyenne Light and Black Hills Power asset programs support a comprehensive, risk-based approach and consider the specific needs of the service territory. The utilities apply industry leading approaches when implementing these programs. The result is improved system reliability and a significant reduction in vegetation-caused outages.

Protecting Customers

Customers are central in all decisions.

The Black Hills Corporation website contains a wealth of information for customers. One page explains how power is delivered to customers through the transmission and distribution system.[33] A second page contains numerous links that teach customers how to be safe around electricity, including topics such as:[34]

- What to do when a power line is down
- What to do when the lights go out
- Call (811) before you dig
- How to be safe around power lines
- Where to plant trees
- How and why the utilities trim trees
- How the utilities prepare for storms
- How to be safe during storms
- What is energy theft and how to report it
- How power quality affects you and your devices
- Energy information for kids

Vegetation Management

Cheyenne Light and Black Hills Power employ an integrated vegetation management program. The program calls for using mechanical equipment, manually clearing and applying herbicides to manage the right-of-way for power lines, and selectively controlling incompatible plant species. The goal is to preserve low-growing grasses, herbs, and woody shrubs.

33 https://www.blackhillscorp.com/learn-about-energy/electricity/transmission-distribution

34 https://www.blackhillscorp.com/learn-about-energy/energy-safety

Properly managed, this low-growing vegetation eventually dominates the right-of-way. Studies show this meadow-like setting enhances wildlife habitat by promoting vegetation preferred by birds, deer, and small animals while reducing the need for future treatments. Cheyenne Light and Black Hills Power have made significant progress adopting a progressive integrated vegetation management program to both decrease maintenance costs and greatly increase wildlife habitat value.

Actions demonstrate commitment to the environment and the communities that the utilities serve. In 2019, Black Hills Corporation enrolled 1,000 acres of the Black Hills Power transmission right of way in the National Wild Turkey Federation's Energy for Wildlife Habitat Endorsement Program. Vegetation management specialists worked with the federation to create a beneficial program, encouraging habitat enhancement on energy corridors including areas within the Black Hills National Forest.

Tree Trimming

Trimming trees improves reliability by reducing outages in good weather and especially in bad weather when energy is most needed. Trim cycles depend on the tree species and anticipated growth rates, the proximity of branches to power lines, and the voltage of the affected power lines. Cheyenne Light and Black Hills Power notify affected customers before trimming trees. Table 06-2 describes the tree trimming clearances for various power lines.

Voltage of Power Lines	General Clearance Specification
230 kV transmission power lines	30 feet, or to the nearest lateral branch on each side of the outer most conductors
69 kV sub-transmission power lines	20 feet, or to the nearest lateral branch on each side of the outer most conductors
Below 69 kV distribution power lines	15–20 feet for fast-growing trees (for example, Siberian Elm, Box Elder, Silver Maple); 10 feet, or to the nearest lateral branch
Secondary power lines	1–3 feet of clearance

Table 06-2. Tree Trimming Specifications

The goal of Cheyenne Light and Black Hills Power is to keep trees healthy while preventing interference with power lines. The utilities follow the science-based lateral pruning method developed by the International Society of Arboriculture and approved by the National Arborists Association and National Arbor Day Foundation. Lateral pruning makes the overall structure of the tree stronger and more resistant to high winds and heavy ice loads. Future growth is directed away from power lines.

Cheyenne Light and Black Hills Power do not top, round over, or shape trees. The National Arbor Day Foundation discourages topping because it makes trees more prone to co dominate stems, narrow branch angles, weak attached branches, and disease and insect problems. The degree to which a tree is trimmed depends on many factors, including the tree species, the health of tree, voltage of power lines, proximity to the lines, and how close branches are to those lines.

Cheyenne Light and Black Hills Power remove tree limb debris as it occurs. If weather or equipment problems hinder safe removal, the utilities return to clean up as soon as possible. Cheyenne Light and Black Hills Power sometimes leave debris in rural areas or when customers request that it be left.

Trees sometimes need to be removed. Likely candidates include diseased, dying, and storm damaged trees; trees likely to be severely deformed by necessary trimming, and trees that will grow to conflict with the electric lines. Cheyenne Light and Black Hills Power obtain written permission from the owner of the tree before removing it. The utilities treat stumps of removed trees that are likely to grow back with approved herbicides.

Line Patrols

The Cheyenne Light and Black Hills Power line patrol program is key to providing quality service to customers. This program, which requires the inspection of the electric infrastructure on a five-year cycle, allows utility industry experts to assess the condition of lines and equipment. Proactive identification of defective or damaged equipment improves reliability while keeping utility employees and communities safe from potential electric infrastructure hazards.

There are a number of line patrol methods available to the industry including ground line patrol, arial patrols and Light Detection and Ranging (LiDAR). Cheyenne Light and Black Hills Power require a ground line patrol on all electric infrastructure and utilize the arial and LiDAR methods primarily on the Transmission infrastructure.

Pole Inspections

Cheyenne Light and Black Hills Power implement a robust pole inspection program. This centrally managed program drives toward proactive identification of structural defects that could later result in a pole failure. An effective inspection and treatment program extends the life of the asset keeping replacement costs to a minimum.

Cheyenne Light and Black Hills Power inspect poles based on a 10-year cycle which compares favorably to the United States Department of Agriculture recommendations. Visual, sounding, bore and excavation inspections are completed on all wood poles excluding laminated structures. This approach aligns with industry best practices and identifies 90%+ of poles with structural defects.

Poles identified as having a structural defect will be reinforced or replaced in a specified timeframe based on a reject classification. The pole inspection program positions Cheyenne Light and Black Hills Power to deliver safe and reliable service to customers.

Outage Management

Unplanned outages happen. Equipment fails and nature intervenes. Planned outages also occur to ensure safety. Cheyenne Light and Black Hills Power manage both types of outages through thorough planning to continue to deliver safe, reliable energy.

For planned distribution outages, Cheyenne Light and Black Hills Power employ an internal process to request and evaluate the potential outage and approve or deny it based on circumstances. The internal review ensures a high level of safety and reliability during the outage.

For planned transmission outages, Cheyenne Light and Black Hills Power follow a process for reviewing requests that meets the requirements of the BA and the reliability coordinator. To comply with OATT requirements, the utilities post transmission outages on the Open Access Same-Time Information System (OASIS).

Cheyenne Light and Black Hills Power proactively prepare for unplanned weather-related outages. The utilities monitor weather conditions for storms that might adversely affect the transmission and distribution system. When weather interrupts service, service crews immediately drive to the areas most affected by the storm to address any issues and restore power. Cheyenne Light and Black Hills Power understand that sometimes the situation exceeds their capacity. In these instances, outside contractors and local emergency officials work with the service crews and suppliers keep inventories available for such emergencies. Throughout the process, the utilities update the media with information about restoring service.

CAPITAL INVESTMENTS

Planning and Implementation

Cheyenne Light and Black Hills Power follow a project lifecycle management (PLM) process to plan and implement capital investments in their transmission and distribution systems. The PLM process follows industry best practices developed by the Project Management Institute, the recognized world leader.

The PLM process manages a project's entire lifecycle, including planning, engineering, procuring, and constructing the project. Project managers rely on PLM to manage the scope, schedule, cost, and quality of a project through its completion. PLM is a phase-gate structure, a technique used to guide a project from conception to launch. It requires a review—a gate—of each project stage before moving on to the next.

New project ideas are derived from various sources: a planning study, a reliability issue, a new customer opportunity, or other initiative. A project sponsor captures the idea and submits a capital project request form. Transmission and Engineering Services (T&ES), an internal team—the sponsor, transmission and distribution planner, engineering, and project delivery—establish a preliminary scope, project duration, and cost. Using the Capital Scoring Ranking system, T&ES ranks every new project deemed prudent in five categories: system reliability; safety; legal and regulatory compliance; financial return; and the impact to the public, business, and customers.

In the first quarter of each year, T&ES reviews the scope, schedule, and cost of every existing and new project and ranks them in priority for completion in a five-year plan. T&ES then submits the plan for budget approval. Projects can be implemented following an approved budget. Implementation involves first establishing a project team. This team follows the PLM process and when finished, the operations division assumes control.

Transmission and Distribution Projects

Cheyenne Light and Black Hills Power continually upgrade and rebuild their transmission and distribution systems to ensure reliability.

To better manage this process, Cheyenne Light and Black Hills Power developed the Distribution System Integrity Program (DSIP). This program enables the utilities to programmatically and systemically replace or rebuild aging distribution assets before they fail or present a risk to customers.

Every year, both utilities evaluate their transmission systems to determine which equipment needs to be upgraded, rebuilt, or replaced. The utilities create a budget and a timeline for these changes based on their risk to reliability or safety.

Cheyenne Light T&D Projects

Cheyenne Light is currently working on several transmission and distribution projects to rebuild aging infrastructure and add new assets to serve increased customer load.

115 kV East Business Park to Skyline Rebuild. The existing eight-mile 115 kV line between East Business Park and Skyline substations was aged and has been rebuilt with greater capacity for future customer load growth. The project was completed in June 2021.

115 kV Campstool Expansion. This expansion includes three projects that focus on serving new data center load:

- Build the new 115 kV and 24.9 kV Campstool substation.
- Add two transmission lines, each approximately 1.5 miles long.
- Expand the existing East Business Park substation and associated facilities.

This project is scheduled to be completed by February 2022.

115 kV Sweetgrass Project. This project also focuses on serving new data center load. The project has five components:

- Build a new 115 kV Sweetgrass substation.
- Build a new 115 kV Bison substation.
- Expand the existing CPGS substation.
- Expand the existing South Cheyenne substation.
- Install seven new transmission lines totaling approximately 11 miles associated with the substations.

This project is planned to be completed by June 2023.

Figure 06-1 depicts a diagram of the Sweetgrass project.

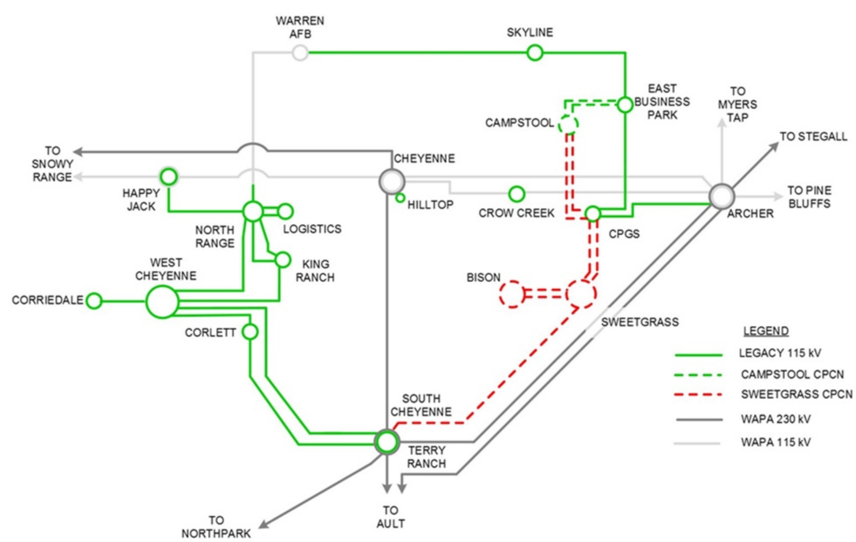


Figure 06-1. Sweetgrass Project Diagram

Black Hills Power T&D Projects

Black Hills Power has completed and is currently working on transmission and distribution projects that rebuild aging infrastructure and add needed transformers.

230 kV West Rapid to South Rapid Rebuild. The existing 6.3-mile 230 kV line between the West Rapid City and South Rapid City substations was rebuilt to maintain safe, reliable service. The project was completed in March 2021.

230 kV West Rapid to Lange Rebuild. The existing two-mile 230 kV line between the West Rapid City and Lange substations was rebuilt to maintain safe, reliable service. The project was completed in March 2021.

230 kV Lange to Lookout Rebuild. The aged 54-mile 230 kV line between the Lange and Lookout substations is being rebuilt to maintain safe, reliable service. The project is scheduled to be completed by December 2021.

230 kV/69 kV Yellowcreek Transformer Addition. This project adds a second 100 MVA 230 kV/69 kV transformer at the Yellowcreek substation to address growing customer energy demand and mitigate the risk of potential overloading identified in transmission planning studies. This project is scheduled to be completed by December 2021.

230 kV Lookout to Wyodak Rebuild. This project is a rebuild of the existing 85-mile 230kV line between Lookout and Wyodak substations to maintain safe, reliable service. The project is scheduled to be completed by December of 2022.

07. MODELING APPROACH AND ASSUMPTIONS

Many key assumptions underlie the modeling and analysis of the IRP. These assumptions include planning periods, planning reserve margin, load forecasts, fuel price forecasts, emission costs and mandates, energy efficiencies, financial considerations, existing resources, candidate resource options, and risk factors.

FOUNDATIONAL PLANNING ELEMENTS

Wyoming IRP guidelines suggest utilities illustrate resource needs over the near-term and long-term planning horizons.

Near-Term Need Planning Period

The IRP employs a six-year near-term need planning period that addresses the years 2021–2026. This time period includes the years the IRP identified Black Hills Power's need for additional resources. The near-term need period provides adequate time for acquiring the necessary resources to meet customer electricity needs.

Long-Term Planning Period

The IRP is based on a long-term planning period of 2021 through 2040. Cheyenne Light and Black Hills Power selected this planning period because it is sufficiently long to incorporate the operating life expectancies of both thermal and renewable resources.

Reserve Margin

The IRP models develop an adequate resource portfolio to cover peak resource requirements plus a planning reserve margin of 15 percent.

Planning with a 15 percent reserve margin ensures that Cheyenne Light and Black Hills Power have sufficient capacity resources to reliably meet demand while accounting for a number of unplanned possibilities (such as fluctuating load, variable levels of renewable resources, extreme weather conditions, and unplanned outages). The utilities plan to continue to review this reserve margin in future IRPs especially as renewable resources increase in the generation mix.

Cheyenne Light's peak resource requirement used in modeling is forecast to be 215 MW in 2021 with a large single unit contingency of 90 MW to account for the potential loss of Wygen II. Black Hills Power's peak resource requirement used in modeling is forecast to be 372 MW in 2021 with a large single unit contingency of 80 MW to account for the potential loss of Neil Simpson II.

Cheyenne Light and Black Hills Power can each rely on the Northwest Power Pool (NWPP) for approximately two hours after a forced outage, but then must replace the lost capacity.

The NWPP has adopted the WECC's Standard BAL-002-WECC-2a for Contingency Reserves and the group as a whole meets these criteria.[35] This standard includes reliability performance criteria such as minimum contingency reserves, types and levels of reserves, methods for measurement and documentation of contingency reserves, and compliance criteria.

35 See Appendix B for the entire WECC standard.

LOAD FORECAST

The starting point for IRP 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 IRP employs an econometric forecasting methodology to forecast retail peak demand and energy. Cheyenne Light and Black Hills Power gathered and refined a variety of different types of datasets, including historical load, revenue, 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, and the effects of DSM plans to the base load forecast produced from the econometric methods. The final system-level major customer class energy forecasts were computed by adding large customer loads, including their anticipated future load growth, losses, and accounting for the effects of DSM plans to the base energy forecasts calculated through the regression analysis. The IRP developed base, low, high, and high-high load forecasts, and includes system-level demand and major customer class energy forecasts using historical data.

Cheyenne Light's final system-level peak demand and energy forecasts excluded LPCS loads and any potential BCIS loads. The type of service offered under the associated tariffs do not require Cheyenne Light to include them in the IRP planning process.

Peak Demand

Peak System Demand represents the highest point of customer usage for a single hour for the system in total.

Utility	Summer Peaks (MW)				
	2016	2017	2018	2019	2020
Black Hills Power	359	362	352	345	378
Cheyenne Light	228	231	230	233	227
	Winter Peaks (MW)				
Black Hills Power	307	324	321	331	304
Cheyenne Light	216	211	207	206	209

Table 07-1. Cheyenne Light and Black Hills Power Peak Demand Trends

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. The IRP process utilized this software to develop statistical models that estimate the effect of various factors (for example, weather) on customer sales, the number of customers served, and system peak demand. The explanatory factors used in these equations consist of weather, electricity prices (calculated as average revenue per-kWh), 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, removing potential concerns about biased inputs.
- Providing measures as to 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, seasonal patterns, or retail electricity prices. The resulting estimates of the relationship between each driver and the associated outcome (for example, sales) are then applied to forecasts relative to the drivers to develop the forecast sales, demand, or number of customers served. The statistical models are reviewed and refined to ensure the estimated relationships are reasonable (that is, correctly signed and of reasonable magnitude).

Load, Economic, and Weather Data

Historical Load Data

The IRP utilizes historical system-level hourly load data. The data set was reviewed to ensure accuracy. Any data anomalies were replaced by averaging data from the hour before and the hour after to create a new value for missing or erroneous data. Cheyenne Light and Black Hills Power identified individual large customer loads to be removed from the historical load data before modeling because updated customer specific load forecasts were available for those customers. The remaining historical data was used in the regression analysis. After the model runs were complete, the excluded customers load forecasted were added back to the base demand forecast to determine the total demand required to be served by each utility.

The major customer class energy forecasts were developed using historic sales and customer count. Sales data by rate identification was gathered, reviewed, and aggregated into major customer classes based on the type of service (for example, residential, commercial, and industrial) as appropriate for each utility. Similar to the hourly load data, a base historical sales dataset was established by removing specific large customers. In addition, historical lighting service data and company-usage data were removed before conducting the sales forecast modeling 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, lighting, and company use were added to the aggregated sales forecast after the major class forecast models were complete.[36]

Economic Data

Economic and demographic historical and forecast data was obtained from Woods & Poole Economics, Inc. for Laramie and Westin counties in Wyoming and Pennington and Lawrence counties in South Dakota. In addition, historical electric price data was gathered from the company's FERC Form 1, page 304 filings reflecting the average annual price of electricity, on a dollar per-kWh basis, for each customer class.

Though this dataset includes several economic variables, Cheyenne Light determined the relevant variables for load forecasts were household total personal income, number of households, and total employment. Black Hills Power determined the relevant variables for load forecasts were total employment and total personal income. Each of these variables was tested in the regression analysis.[37]

Weather Data

Historical weather data was collected from the NOAA National Climatic Data Center's Cheyenne Airport and Pennington, Meade, Butte, Fall River, Custer, and Lawrence county weather stations. The historical 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.[38]

36 The historical load and sales data used in the peak demand and sales models are included in Appendix C, Schedule C-1 and Schedule C-2.

37 The historical and forecasted economic data and historical price data used in the peak demand and sales models are included in Confidential Schedule C-3 of Appendix C.

38 The historical weather data used in the peak demand and sales models is included in Schedule C-4 and Schedule C-5, Appendix C.

Normal Weather Conditions

The weather variables in the energy and demand forecasts were set to reflect normal conditions, interpreted as the average weather conditions over 20 years for Cheyenne Light and 21 years for Black Hills Power, to align with the most historical date of usage data available. In the energy model, the averages of the sum of the cooling degree days and heating degree days over the available time period were used to calculate normal weather for each month. In the peak demand model, each month was determined to be either a predominantly cooling- or heating-peak month, and then only the relevant peak-hours for each month and year were averaged. Those averages were averaged again for each month and used as normalized peak weather conditions.

Forecast Methodology

Multiple combinations of the variables described above were tested during the development of the energy and demand forecasts. The models were refined to ensure the estimates were logical and reasonable (for example, sales increase with CDDs) and statistically significant (or approaching statistical significance). Normal weather conditions were used to forecast energy and demand.

Peak Demand Forecast Methodology

Each utility's system demand forecast is a system-level forecast inclusive of residential, commercial, industrial, and lighting sectors. Each month's peak hours were used to model the monthly peak demand forecast. The resulting estimates were used in combination with normal weather and forecasted economic conditions to forecast peak demands.

Energy Forecast Methodology

To complete the energy forecast, the Cheyenne Light system was disaggregated into four major customer classes: residential, commercial no demand, commercial general service secondary and primary, and industrial. The residential customer class is an aggregation of all of Cheyenne Light's residential rate IDs. The commercial no demand class is an aggregation of Cheyenne Light's commercial rate IDs without a demand charge. The commercial general service secondary class is an aggregation of Cheyenne Light's general service secondary rate IDs, and the commercial general service primary class is an aggregation of Cheyenne Light's general service primary rate IDs. Large industrial contracts rate IDs constitute the industrial class. The IRP's load forecast excluded all LPCS loads and any potential BCIS loads.

To complete the energy forecast, the Black Hills Power system was disaggregated into four major customer classes: residential, commercial, municipal, and industrial. The residential customer class is an aggregation of all of Black Hills Power's residential rate IDs. The commercial class is an aggregation of Black Hills Power's commercial rate IDs. The municipal class is an aggregation of Black Hills Power's municipal rate IDs. Black Hills Power's large industrial rate IDs constitute the industrial class.[39]

Demand-Side Management

Demand-side management can be the lowest cost resource available. Instead of meeting demand, DSM offsets demand by enabling customers to lower their energy footprint.

Figure 07-1 depicts the energy efficiency goals from 2011 through 2021 for Cheyenne Light.

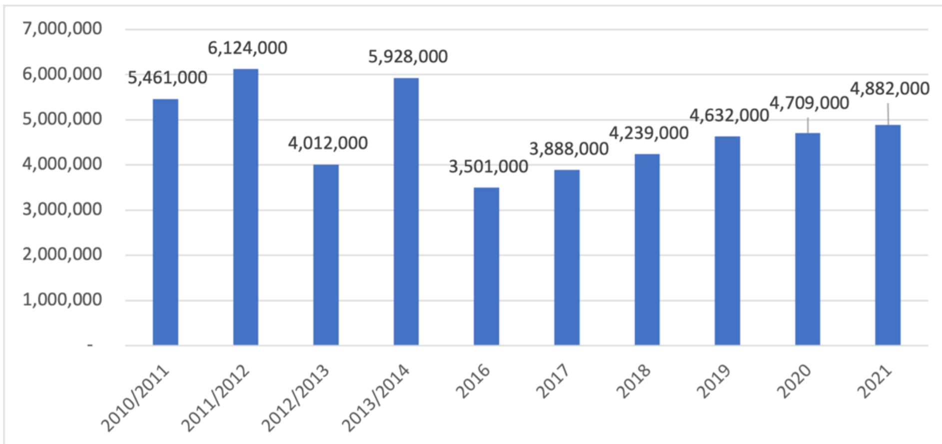


Figure 07-1. 2011–2026 Cheyenne Light Energy Efficiency Actual and Projected Savings (kWh)

Cheyenne Light's tri-annual DSM plan, originally implemented for 2016–2018, was renewed in 2018 for the years 2019–2021. The anticipated DSM plan for 2022–2024 was not finalized when the IRP was developed. Black Hills Power's most recent South Dakota DSM plan was filed in 2017 and ended in 2020.

39 Summaries of the final energy and demand equations are described in Appendix L. Also included in Schedules C-1, C-2, and Confidential C-3 of Appendix C, are the historical and forecasted values for variables that were used in the models. The resulting forecasts, monthly and annual, for all customer classes are in Schedules C-8 and C-9, Appendix C.

Table 07-2 compares the forecasted peak savings with the actual saving for each year of Cheyenne Light's 2016–2018 and 2019–2021 DSM Plan. Load forecasts for both the 2018 and 2021 IRPs were adjusted to include the forecasted reductions in both the peak demand and energy forecasts. Since the 2022–2024 DSM plan filing has not been finalized, the potential reductions were not incorporated into the 2021 load forecast.

DSM Plan Year	Projected Peak Savings (MW)	Actual Peak Savings (MW)	Projected Energy Savings (MWh)	Actual Energy Savings (MWh)
2016	1.648	0.904	3,501	3,230
2017	1.817	1.243	3,888	5,387
2018	1.325	1.125	4,240	5,014
2019	0.978	1.135	4,632	4,676
2020	0.981	1.652	4,709	7,051
2021	1.006	–	4,882	–

Table 07-2. Cheyenne Light Tri-Annual DSM Plan Projected and Actual Savings 2016–2021

Table 07-3 lists the annual adjustments of the load forecast to peak demand (MW) and energy (MWh) with the reductions realized from Cheyenne Light's current DSM plan. The demand adjustment reflects the expected savings achieved as of July 1; the energy adjustment reflects the expected savings achieved over the entire year. Because the 2022-

2024 DSM plan was not finalized at the time of the analysis for the IRP, the potential reductions were not incorporated into the load forecast.

Year	Projected Peak Savings (MW)	Projected Energy Savings (MWh)
2021	1.57	9,591
2022	1.99	9,591
2023	1.99	9,591
2024	1.99	9,591
2025	1.99	9,591
2026	1.99	9,591
2027	1.99	9,591
2028	1.99	9,591
2029	1.99	9,591
2030	1.99	9,591
2031	1.99	9,591
2032	1.99	9,591
2033	1.99	9,591
2034	1.99	9,591
2035	1.99	9,591
2036	1.99	9,591
2037	1.99	9,591
2038	1.99	9,591
2039	1.99	9,591
2040	1.99	9,591

Table 07-3. Cheyenne Light DSM-Related Load Forecast Adjustments: 2021–2040

The cost-effectiveness analysis for the total Cheyenne Light DSM program uses a total resource cost test to predict program cost benefits. The test is calculated using a variety of input data that includes retail rate, commodity cost, demand cost, variable operations and maintenance expenses, environmental externalities, discount and escalation rates, as well as demand and energy savings and number of participants. The total resource cost for all Cheyenne Light DSM program was $976,388 in 2019 and $794,604 in 2020.

Black Hills Power DSM Programs

Black Hills Power's South Dakota tri-annual plan for 2017–2019 resulted in reduced demand and energy savings. On September 1, 2020, the utility discontinued its South Dakota DSM program because of the inability to establish a portfolio of energy efficient offerings that are and that will remain cost-effective. Black Hills Power does not have DSM programs in Wyoming or Montana.

Large Customer Growth Assumptions

Cheyenne Light and Black Hills Power periodically review the growth plans of the largest customers in their service territories. These load additions encompass growth greater than the anticipated growth rates included in the econometric load forecasts. These expected load increases can be uncertain and depend to a great extent on economic conditions.

Anticipated large customer load additions were compiled based on information gathered by 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 07-4 lists Cheyenne Light's anticipated large customer load additions (with confidence factor applied) for the near-term planning period.

Customer	Load Factor	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)
Large Customer A	81.78%	–15.08	3.50	0.00	0.00	0.00	0.00
Large Customer B	83.81%	–2.51	2.73	0.00	0.00	–2.73	2.51
Large Customer C	87.36%	0.00	1.00	0.00	–1.00	0.00	0.00
Large Customer D	39.30%	0.00	0.23	0.00	0.00	0.00	0.00

Table 07-4. Cheyenne Light Large Customer Load Additions and Reductions 2021–2026

Table 07-5 lists Black Hills Power's anticipated large customer load additions (with confidence factor applied) for the near-term planning period.

Customer	Load Factor	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)
Large Customer A	82.00%	0.00	0.00	0.00	0.00	–3.00	-2.00
Large Customer B	47.00%	0.00	0.00	0.00	0.00	0.00	0.00
Large Customer C	37.00%	0.00	0.00	0.00	0.00	0.00	0.00
Large Customer D	9.00%	0.00	0.00	0.00	0.00	0.00	0.00
Large Customer E	43.00%	0.00	0.00	0.00	0.00	0.00	0.00
Large Customer F	25.00%	2.25	0.00	0.00	0.00	0.00	0.00
Large Customer G	48.00%	0.00	0.00	0.00	0.00	0.00	0.00
Large Customer H	88.00%	0.75	0.25	0.00	0.00	0.00	0.00
Large Customer I	69.00%	0.00	0.00	0.00	0.00	0.00	0.00
Large Customer J	75.00%	1.50	0.00	0.00	0.75	–1.13	0.00
Large Customer K	55.00%	0.18	0.44	0.04	0.00	0.00	0.00
Large Customer L	56.00%	1.10	0.10	0.00	0.00	0.00	0.00
Large Customer M	39.00%	1.00	0.00	0.00	0.00	0.00	0.00
Large Customer N	66.00%	0.50	0.25	0.00	0.00	0.00	0.00

Table 07-5. Black Hills Power Large Customer Load Additions and Reductions 2021–2025

Base Peak Demand and Annual Energy Forecasts

The final base system-level monthly peak demand forecast was computed by adding anticipated future load growth of large customers into the load forecast calculated by 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, lighting service, company use, and the effects of DSM to the energy forecasts calculated through the regression analysis. Cheyenne Light's final system-level peak demand and energy forecasts excluded all LPCS loads and any potential BCIS loads.

Combined transmission and distribution losses were also added into the monthly energy forecast for the Cheyenne Light and Black Hills Power systems. The system level transmission and distribution losses are 7.38 percent for Cheyenne Light and 7.61 percent for Black Hills Power. Separate system loss estimates cannot be made for transmission and distribution because the forecast was not developed at the transmission and distribution voltage level, nor was the transmission and distribution losses developed at the customer class level.

After the final base system-level peak demand and energy forecasts were completed for Cheyenne Light and Black Hills Power, a joint system forecast was computed. This calculation took the hourly load forecast of each utility and added them together to produce the hourly joint system forecast. Aggregating the two utilities into the joint forecast at the hourly level appropriately reflected the diversity in load between the two utilities. Since Cheyenne Light and Black Hills Power do not peak at the same hour of the year, the aggregation allowed for the loads to be captured more realistically and created a new joint peak.

Table 07-6 lists the peak demand and annual energy forecasts values for the base load forecast.

Year	Cheyenne Light		Black Hills Power		Cheyenne Light and Black Hills Power Joint	
	Peak Demand (MW)	Annual Energy (MWh)	Peak Demand (MW)	Annual Energy (MWh)	Peak Demand (MW)	Annual Energy (MWh)
2021	215	1,351,043	372	2,012,194	543	3,363,230
2022	224	1,418,053	375	2,033,867	550	3,451,920
2023	225	1,422,976	377	2,037,056	552	3,460,070
2024	226	1,419,010	379	2,041,755	567	3,460,760
2025	225	1,401,578	377	2,014,141	577	3,415,730
2026	229	1,423,319	377	2,005,311	562	3,428,610
2027	231	1,425,366	380	2,012,378	565	3,437,740
2028	233	1,427,324	383	2,022,806	560	3,450,130
2029	234	1,429,203	385	2,034,011	564	3,463,220
2030	236	1,430,984	387	2,032,940	580	3,463,930
2031	238	1,432,618	389	2,034,151	600	3,466,760
2032	239	1,434,109	390	2,034,999	580	3,469,110
2033	241	1,435,509	392	2,035,423	569	3,470,940
2034	242	1,436,862	393	2,035,504	572	3,472,360
2035	244	1,438,208	395	2,035,289	575	3,473,500
2036	245	1,439,533	396	2,034,806	613	3,474,330
2037	247	1,440,769	397	2,034,089	591	3,474,860
2038	248	1,441,903	399	2,033,149	592	3,475,060
2039	250	1,442,976	400	2,032,063	580	3,475,050
2040	251	1,444,052	401	2,030,889	584	3,474,940

Table 07-6. Cheyenne Light and Black Hills Power Baseload Forecast

Low, High, and High-High Forecasts

The Base load forecast represents 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 IRP models low, high, and high-high load forecasts in addition to the base load forecast. For the high and low load forecasts, an 80 percent confidence interval band around the base demand and sales forecasts was modeled. The forecast represents the sales and demand levels that are expected to occur on average. However, considerable uncertainty remains regarding the economic conditions that will occur during the forecast period. For example, a recession could arise or a period of sustained growth could occur. The confidence interval indicates the extent to which demand and sales can vary because of such uncertainties.

To capture a wide range of economic conditions, Cheyenne Light and Black Hills Power based their variability calculations on data beginning in 1969 and ending with the most recent observed data point. The data is provided by Woods & Poole and focus on the variables used in the forecast models. The variability calculation takes a mid- to long-term perspective based on the average annual percentage change over a ten-year period.

Specifically, the utilities calculated the year-to-year percentage changes in the economic variable (for example, gross regional product, total employment, or personal income) and then calculated 10-year moving averages of those percentage changes. The peak demand model provided them with an estimate of the effect of changes in the economic variable on changes in peak demand, along with a standard error associated with the estimate. These two uncertainties (in economic conditions over time and in the estimated effect of economic conditions on peak demand) are combined to produce the confidence interval around the demand and sales forecasts.[40]

The high-high load forecast adds an additional 25 MW step load to the high load forecast beginning in 2024. The high-high load forecast is intended to account for potential large growth resulting from a new customer (for example, the addition of large new data center load), faster than expected electrification (for example, higher adoption rate of electric vehicles or building electrification), or other potential load increases. While each potential load driver could have unique loads and timing, a single high-high load forecast was developed to analyze the impacts of high-high load growth.

40 The specific steps used to develop the confidence interval are described in Appendix L.

Table 07-7 details the base, low, high, and high-high summer peak demand and the annual energy load forecasts for the planning period for Cheyenne Light. These forecasts include the impact of DSM and energy efficiency programs.

Cheyenne Light								
	Summer Peak Demand (MW)				Annual Energy (GWh)			
Year	Base	Low	High	High-High	Base	Low	High	High-High
2021	215	213	216	216	1,351	1,266	1,425	1,425
2022	224	221	226	226	1,418	1,299	1,516	1,516
2023	225	222	229	229	1,423	1,300	1,525	1,525
2024	226	221	231	256	1,419	1,294	1,524	1,743
2025	225	219	231	256	1,402	1,271	1,508	1,727
2026	229	223	236	261	1,423	1,277	1,532	1,751
2027	231	223	239	264	1,425	1,278	1,535	1,754
2028	233	224	242	267	1,427	1,279	1,539	1,758
2029	234	225	245	270	1,429	1,280	1,542	1,761
2030	236	225	247	272	1,431	1,280	1,545	1,764
2031	238	226	250	275	1,433	1,281	1,548	1,767
2032	239	226	253	278	1,434	1,281	1,551	1,770
2033	241	227	255	280	1,436	1,282	1,553	1,772
2034	242	228	258	283	1,437	1,282	1,556	1,775
2035	244	228	261	286	1,438	1,283	1,558	1,777
2036	245	229	263	288	1,440	1,283	1,560	1,779
2037	247	229	266	291	1,441	1,284	1,562	1,781
2038	248	230	268	293	1,442	1,284	1,564	1,783
2039	250	230	271	296	1,443	1,284	1,566	1,785
2040	251	231	274	299	1,444	1,285	1,568	1,787

Table 07-7. Cheyenne Light: Peak Demand and Annual Load Forecast Comparison

Table 07-8 details the base, low, high, and high-high summer peak demand and the annual energy load forecasts for the planning period for Black Hills Power. These forecasts include the impact of DSM and energy efficiency programs.

Black Hills Power								
	Summer Peak Demand (MW)				Annual Energy (GWh)			
Year	Base	Low	High	High-High	Base	Low	High	High-High
2021	372	371	372	372	2,012	1,995	2,030	2,030
2022	375	373	376	376	2,034	2,015	2,053	2,053
2023	377	375	378	378	2,037	2,017	2,057	2,057
2024	379	377	382	407	2,042	2,021	2,062	2,281
2025	377	374	380	405	2,014	1,993	2,035	2,254
2026	377	373	381	406	2,005	1,983	2,027	2,246
2027	380	376	385	410	2,012	1,990	2,035	2,254
2028	383	378	388	413	2,023	1,999	2,046	2,265
2029	385	380	391	416	2,034	2,010	2,058	2,277
2030	387	381	393	418	2,033	2,008	2,057	2,276
2031	389	382	395	420	2,034	2,009	2,059	2,278
2032	390	383	397	422	2,035	2,010	2,060	2,279
2033	392	384	399	424	2,035	2,010	2,061	2,280
2034	393	385	401	426	2,036	2,010	2,061	2,280
2035	395	386	403	428	2,035	2,010	2,061	2,280
2036	396	387	405	430	2,035	2,009	2,060	2,279
2037	397	388	407	432	2,034	2,008	2,060	2,279
2038	399	389	409	434	2,033	2,007	2,059	2,278
2039	400	390	411	436	2,032	2,006	2,059	2,278
2040	401	390	413	438	2,031	2,004	2,058	2,277

Table 07-8. Black Hills Power: Peak Demand and Annual Load Forecast Comparison

Table 07-9 details the base, low, high, and high-high summer peak demand and the annual energy load forecasts for the planning period for Cheyenne Light and Black Hills Power jointly. These forecasts include the impact of DSM and energy efficiency programs.

Cheyenne Light and Black Hills Power Joint						
	Summer Peak Demand (MW)			Annual Energy (GWh)		
Year	Base	Low	High	Base	Low	High
2021	543	545	556	3,363	3,261	3,455
2022	550	548	573	3,452	3,314	3,569
2023	552	545	576	3,460	3,318	3,582
2024	567	579	599	3,461	3,315	3,586
2025	577	573	595	3,416	3,264	3,544
2026	562	554	581	3,429	3,261	3,559
2027	565	556	586	3,438	3,268	3,570
2028	560	547	589	3,450	3,278	3,585
2029	564	550	593	3,463	3,290	3,600
2030	580	585	624	3,464	3,289	3,603
2031	600	586	628	3,467	3,290	3,607
2032	580	565	608	3,469	3,291	3,611
2033	569	559	607	3,471	3,292	3,614
2034	572	555	610	3,472	3,292	3,616
2035	575	557	613	3,474	3,293	3,619
2036	613	594	649	3,474	3,292	3,621
2037	591	571	626	3,475	3,292	3,622
2038	592	571	629	3,475	3,291	3,624
2039	580	565	626	3,475	3,290	3,625
2040	584	562	628	3,475	3,289	3,626

Table 07-9. Cheyenne Light and Black Hills Power Joint: Peak Demand and Annual Load Forecast Comparison

Table 07-10 compares Cheyenne Light's total system summer and winter peak demand forecast for the planning period.

Cheyenne Light								
Year	Summer Peak Demand (MW)				Winter Peak Demand (MW)			
	Base	Low	High	High-High	Base	Low	High	High-High
2021	215	213	216	216	203	195	211	211
2022	224	221	226	226	209	200	218	218
2023	225	222	229	229	210	200	221	221
2024	226	221	231	256	211	200	222	247
2025	225	219	231	256	213	201	225	250
2026	229	223	236	261	214	201	228	253
2027	231	223	239	264	216	202	230	255
2028	233	224	242	267	217	202	233	258
2029	234	225	245	270	219	203	236	261
2030	236	225	247	272	220	203	238	263
2031	238	226	250	275	222	204	241	266
2032	239	226	253	278	223	205	243	268
2033	241	227	255	280	225	205	246	271
2034	242	228	258	283	226	206	249	274
2035	244	228	261	286	228	206	251	276
2036	245	229	263	288	229	207	253	278
2037	247	229	266	291	230	207	256	281
2038	248	230	268	293	232	208	258	283
2039	250	230	271	296	233	208	261	286
2040	251	231	274	299	234	209	263	288

Table 07-10. Cheyenne Light: Seasonal Peak Demand Comparison

Table 07-11 compares Black Hills Power's total system summer and winter peak demand forecast for the planning period.

Black Hills Power								
	Summer Peak Demand (MW)				Winter Peak Demand (MW)			
Year	Base	Low	High	High-High	Base	Low	High	High-High
2021	372	371	372	372	326	325	326	326
2022	375	373	376	376	328	327	329	329
2023	377	375	378	378	330	328	332	332
2024	379	377	382	407	332	330	334	359
2025	377	374	380	405	330	327	332	357
2026	377	373	381	406	329	326	332	357
2027	380	376	385	410	332	329	336	361
2028	383	378	388	413	335	331	339	364
2029	385	380	391	416	337	332	341	366
2030	387	381	393	418	338	333	343	368
2031	389	382	395	420	340	334	345	370
2032	390	383	397	422	341	335	347	372
2033	392	384	399	424	342	336	349	374
2034	393	385	401	426	343	337	350	375
2035	395	386	403	428	345	338	352	377
2036	396	387	405	430	346	338	354	379
2037	397	388	407	432	347	339	355	380
2038	399	389	409	434	348	340	357	382
2039	400	390	411	436	349	340	358	383
2040	401	390	413	438	350	341	360	385

Table 07-11. Black Hills Power: Seasonal Peak Demand Comparison

Historical Peak Demand and Annual Energy

Cheyenne Light and Black Hills Energy have historically experienced peaks in the summer and winter. Typically, summer peaks are higher than winter peaks. Table 07-12 details the annual peak demand and annual energy for 2016–2020, the five years immediately preceding the IRP planning period.

Year	Peak Demand		Annual Energy		Load Factor (%)
	Summer (MW)	% Change	GWh	% Change	
Cheyenne Light					
2016	228	–	1,505	–	75.4
2017	231	1.3	1,496	-0.6	73.9
2018	230	-0.4	1,512	1.1	75.1
2019	233	1.3	1,497	-1.0	73.3
2020	227	-2.6	1,463	-2.3	73.6
Average Annual Growth (%)		-0.1		-0.7	
Black Hills Power					
2016	359	–	1,893	–	60.2
2017	362	0.8	1,912	1.0	60.3
2018	352	-2.8	1,916	0.2	62.2
2019	345	-2.0	1,948	1.7	64.5
2020	378	9.6	1,924	-1.3	58.1
Average Annual Growth (%)		1.4		0.4	

Table 07-12. Historical Peak Demand and Annual Energy

Annual energy includes transmission and distribution losses. Since 2016, the summer peak for Cheyenne Light has experienced an average annual growth rate of –0.1 percent and the historical annual energy experienced an average annual growth rate of –0.7 percent. This is mostly due to a decrease in load for one large customer.

Since 2016, Black Hills Power has experienced an average annual growth rate of 1.4 percent and the historical annual energy experienced an average annual growth rate of 0.4 percent.

Table 07-13 compares the projected peak demand and annual energy amounts from the last Cheyenne Light IRP with the 2021 IRP. The 2021 Cheyenne Light load forecast includes the effects of one large customer's load reduction.

Cheyenne Light				
	2018 IRP		2021 IRP	
Year	Peak Demand (MW)	Annual Energy (MWh)	Peak Demand (MW)	Annual Energy (MWh)
2019	228	1,535,621	–	–
2020	230	1,541,816	–	–
2021	232	1,557,571	215	1,351,043
2022	235	1,566,506	224	1,418,053
2023	237	1,575,213	225	1,422,976
2024	239	1,583,855	226	1,419,010
2025	241	1,592,534	225	1,401,578
2026	242	1,601,265	229	1,423,319
2027	244	1,610,038	231	1,425,366
2028	246	1,618,837	233	1,427,324
2029	248	1,627,642	234	1,429,203
2030	250	1,636,486	236	1,430,984
2031	252	1,645,392	238	1,432,618
2032	254	1,654,351	239	1,434,109
2033	256	1,663,371	241	1,435,509
2034	258	1,672,452	242	1,436,862
2035	259	1,681,631	244	1,438,208
2036	261	1,690,981	245	1,439,533
2037	263	1,700,632	247	1,440,769
2038	265	1,710,655	248	1,441,903
2039	266	1,721,013	250	1,442,976
2040	268	1,731,733	251	1,444,052

Table 07-13. Cheyenne Light Historical Peak Demand and Annual Energy Comparison

Table 07-14 compares the projected peak demand and annual energy amounts from the last two Black Hills Power IRPs. The Black Hills Power 2011 IRP load forecast included 23 MW of load from the City of Gillette and the MDU service territory load. The Black Hills Power 2021 IRP load forecast does not include the City of Gillette or MDU.

Black Hills Power				
	2011 IRP		2021 IRP	
Year	Peak Demand (MW)	Annual Energy (MWh)	Peak Demand (MW)	Annual Energy (MWh)
2011	408	2,283,465		
2012	414	2,306,302		
2013	426	2,389,303		
2014	430	2,412,278		
2015	442	2,465,252		
2016	446	2,504,224		
2017	450	2,529,276		
2018	455	2,554,576		
2019	459	2,580,134		
2020	464	2,605,935		
2021	468	2,631,995	372	2,012,194
2022	473	2,658,315	375	2,033,867
2023	478	2,684,898	377	2,037,056
2024	483	2,711,747	379	2,041,755
2025	488	2,738,864	377	2,014,141
2026	492	2,766,253	377	2,005,311
2027	497	2,793,915	380	2,012,378
2028	502	2,821,855	383	2,022,806
2029	507	2,850,073	385	2,034,011
2030	512	2,878,574	387	2,032,940
2031	–	–	389	2,034,151
2032	–	–	390	2,034,999
2033	–	–	392	2,035,423
2034	–	–	393	2,035,504
2035	–	–	395	2,035,289
2036	–	–	396	2,034,806
2037	–	–	397	2,034,089
2038	–	–	399	2,033,149
2039	–	–	400	2,032,063
2040	–	–	401	2,030,889

Table 07-14. Black Hills Power Historical Peak Demand and Annual Energy Comparison

WHOLESALE CONTRACTS

Black Hills Power participates in wholesale energy and capacity transactions, which are added to the retail load forecast to determine the total load to be served. Currently, Black Hills Power has contracts to serve portions of the energy and capacity requirements of MEAN, MDU, and the City of Gillette.

Table 07-15 contains the peak demand and annual energy forecasts values for the wholesale contracts.

	Summer Peak Demand (MW)			Annual Energy (MWh)		
Year	MEAN	MDU	City of Gillette	MEAN	MDU	City of Gillette
2021	15	40	15	131,400	80,376	1,131
2022	15	41	16	131,400	83,682	1,404
2023	10	42	–	105,720	85,428	–
2024	10	43	–	87,840	87,384	–
2025	10	44	–	87,600	89,859	–
2026	10	45	–	87,600	92,117	–
2027	10	46	–	87,600	93,629	–
2028	–	47	–	36,480	94,668	–

Table 07-15. Black Hills Power: Wholesale Contracts

FUEL PRICE FORECASTS

Fuel prices can shift as a result of demand growth, climate legislation, export infrastructure, and supply conditions. Thus, the IRP employs reasonable, recent, and consistent projections of fuel prices in its modeling and analysis.

The IRP uses assumptions based on the HAPG WECC 2020 Fall Reference Case for all natural gas and diesel price forecasts used in the IRP.[41] Coal forecasts are based on internal analysis.

41 See Appendix H: Price and Cost Forecasts for the schedules of all fuel price forecasts.

Natural Gas Price Forecasts

HAPG provided a base, low, and high forecast for both existing and future natural gas-fired resources.

Base natural gas prices reflect expected conditions based on the supply and demand forecasts. To derive the NG Rockies and NG Colorado natural gas prices, the regional basis prices are aggregated at the major trading hubs. The first 12 months of the forecast are driven by Henry Hub futures market prices plus a basis hub differential forward price. For the following 36 months of the forecast period (months 13–48), HAPG blends the futures market price expectations with a long-term fundamental forecast, so that by the end of this period the gas price forecasts are consistent.

Table 07-16 lists the price ranges of Rockies and Colorado natural gas prices from the beginning and ending years of the planning period for the natural gas scenarios.

Scenario	Rockies 2021 Price ($/MMBtu)	Rockies 2040 Price ($/MMBtu)	Colorado 2021 Price ($/MMBtu)	Colorado 2040 Price ($/MMBtu)
Base Natural Gas	3.14	4.75	3.61	5.27
Low Natural Gas	2.46	3.06	2.93	3.58
High Natural Gas	3.84	6.15	4.31	6.67

Table 07-16. Average Annual Rockies Gas Price Forecasts

The natural gas price forecast for resources located in Cheyenne are based on the Rockies forecast plus a basis differential plus transportation costs. The natural gas price forecast for resources located in Gillette and Rapid City are based on the Colorado forecast plus a basis differential plus transportation costs.

Coal Price Forecasts

The coal price forecast is internally developed. All Cheyenne Light and Black Hills Power coal plants are located adjacent to the coal mine and the forecast coal price reflects the cost savings realized from the elimination of transportation and storage.

Coal costs apply to all coal-fired units.

Table 07-17 lists the delivered coal price forecast for the planning period.

Year	Coal Price Forecasts ($/MMBtu)
2021	0.88
2022	0.96
2023	0.96
2024	0.99
2025	1.07
2026	1.05
2027	1.04
2028	1.05
2029	1.07
2030	1.11
2031	1.10
2032	1.12
2033	1.14
2034	1.18
2035	1.17
2036	1.19
2037	1.21
2038	1.25
2039	1.24
2040	1.26

Table 07-17. Coal Price Forecasts

Diesel Price Forecasts

Diesel costs apply to the Ben French Diesels. HAPG provided a base forecast for existing diesel-fired resources.

Table 07-18 lists the price ranges of Number 2 (Distillate) diesel prices from the beginning and ending years of the planning period for the scenarios.

Scenario	No. 2 (Distillate) 2021 Price ($/MMBtu)	No. 2 (Distillate) 2040 Price ($/MMBtu)
Base Diesel	7.89	15.77

Table 07-18. No. 2 (Distillate) Diesel Price Forecasts

Economy Energy Prices

Occasionally, economy energy is available in the market at a cost savings.

For Cheyenne Light, the IRP incorporated an economy energy purchase of up to 100 MW for every hour; for Black Hills Power, the IRP incorporated up to 175 MW for every hour. The joint analysis incorporated economy energy purchases of up to 275 MW for every hour.

Economy energy prices are based on the HAPG WECC 2020 Fall Reference Colorado West market area price forecast.

Table 07-19 lists the price ranges of Colorado West market area from the beginning and ending years of the planning period for the natural gas and environmental scenarios.

Scenario	CO-West 2021 Price ($/MWh)	CO-West 2040 Price ($/MWh)
Base Natural Gas	30.24	42.28
Low Natural Gas	27.75	25.32
High Natural Gas	33.10	48.04
Environmental	30.24	67.59

Table 07-19. Colorado West Price Forecasts

EMISSIONS COSTS

While there is currently no national goal for GHG emission reduction or other environmental-friendly goal, the possibility for such legislation remains large.

Because of the absence of such legislation, the IRP assumes that no carbon taxes will be enacted during the planning period for the base scenario assumptions. The environmental scenario, however, considered a carbon tax. HAPG provided an environmental forecast for a carbon tax beginning in 2023 through the planning period. Table 07-20 lists the carbon taxes assumed for the environmental scenarios.

Year	Carbon Tax ($/ton)	Year	Carbon Tax ($/ton)
2021	0.00	2031	57.98
2022	0.00	2032	59.12
2023	20.40	2033	60.26
2024	31.34	2034	61.39
2025	42.27	2035	62.53
2026	53.21	2036	63.67
2027	54.12	2037	64.80
2028	55.03	2038	65.94
2029	55.94	2039	67.08
2030	56.84	2040	68.21

Table 07-20. Carbon Tax Assumptions (Environmental Scenarios Only)

FINANCIAL ASSUMPTIONS

The IRP's modeling relied on numerous financial assumptions to develop the incremental costs of debt and equity, return on rate base, and interest rate necessary to calculate the total system PVRR for each candidate resource portfolio and scenario.

Table 07-21 presents these financial assumptions.

Assumption	Cheyenne Light	Black Hills Power	Consolidated
Cost of Debt (Interest Rate)	5.72%	Global Settlement[42]	5.94%
Cost of Equity	9.90%	Global Settlement	9.50%
Weighted Average Cost of Capital After Tax[43]	6.30%	6.13%	6.20%
Income Tax Rate	21.00%	21.00%	21.00%
Rate of Escalation (Inflation Rate)	1.50%	1.50%	1.50%
Capital Structure:			
Equity	54.00%	53.00%	53.00%
Debt	46.00%	47.00%	47.00%
Property Tax Rate	0.43%	0.60%	0.53%
25-Year Fixed Charge Rate with Five Year Tax Life Wind and Solar Resources	7.01%	6.89%	6.94%
First Year Recovery Rate (35-Year Life)			
Combined Cycle, Combustion Turbine, Other New	5.99%	5.86%	5.91%
Conversions (25 Year Life)	7.01%	6.89%	6.94%
Battery Storage (20 Year Life)	7.96%	7.85%	7.89%
Neil Simpson Unit 2 Life Extension (20 Year Life)	n/a	7.85%	7.89%
Annual Construction Escalation	1.50%	1.50%	1.50%

Table 07-21. Modeled Financial Assumptions

42 The revenue requirements were agreed upon with the South Dakota Commission. The specific adjustments used by Black Hills Power and the Commission to arrive at the amounts are not stated in public rate orders.

43 The after-tax cost of capital was calculated based on the pre-tax cost of capital approved in the most recent rate review for Cheyenne Light of 7.98% and for Black Hills Power of 7.76%.

EXISTING RESOURCES

This section contains the modeling assumptions used to develop the IRP for all Cheyenne Light and Black Hills Power generation sources, both owned and contracted.[44]

Cheyenne Light

Cheyenne Light's generation resources consist of one wholly-owned coal-fired plant (Wygen II), one natural gas simple cycle CTs, one natural gas combined cycle CT, one wind facility, plus PPAs for two wind facilities and a coal-fired power plant (Wygen I). Table 07-22 lists the modeling assumptions for Cheyenne Light's generation mix.

Generation	Nameplate/ Contract Capacity (MW)	Summer Capacity (MW)	Forced Outage Rate (%)	Scheduled Outage Rate (%)	Ave Heat Rate (Btu/kWh)	CO_2 Emission Rate (lb/MWh)
Wygen II	90	90	3.0	varies	11,936	2,575
Cheyenne Prairie CCCT	40	40	2.0	varies	8,083	962
Cheyenne Prairie SCCT	37	37	2.0	varies	10,220	1,313
Happy Jack PPA	15	4	0.0	0.0	n/a	n/a
Silver Sage PPA	10	3	0.0	0.0	n/a	n/a
Corriedale	20	6	0.0	0.0	n/a	n/a
Wygen I PPA	60	60	3.0	varies	11,956	2,555

Table 07-22. Cheyenne Light Unit Modeling Data

Nameplate capacity is considered to be equivalent to rated capacity. The summer capacity is considered dependable capacity. The annual availability is dependent on the timing of major overhauls as well as actual forced outages.

44 See Chapter 5: Generation Resources for details on these sources.

Black Hills Power

Black Hills Power's owned and co-owned generation resources consist of five small diesel units, six natural gas simple cycle CTs, one natural gas combined cycle CT, three coal-fired power plants, and one wind facility, plus three wind PPAs, one coal PPA, and one pending solar PPA.

Table 07-23 lists the modeling assumptions for Black Hills Power's generation mix.

Generation	Nameplate/ Contract Capacity (MW)	Summer Capacity (MW)	Forced Outage Rate (%)	Scheduled Outage Rate (%)	Ave Heat Rate (Btu/kWh)	CO_2 Emission Rate (lb/MWh)
Ben French Diesels #1–5	2 each	2 each	2.0	varies	16,450	1,658
Ben French SCCTs #1–4	20 each	18 each	2.0	varies	15,621	2,106
Lange SCCT	39	39	2.0	varies	10,188	1,295
Cheyenne Prairie CCCT	55	55	2.0	varies	8,083	962
Neil Simpson SCCT	39	39	2.0	varies	10,188	1,196
Wygen III	52	52	3.0	varies	11,320	2,420
Neil Simpson II	80	80	3.0	varies	12,899	2,790
Wyodak	67	62	3.1	varies	11,877	2,666
Corriedale	32	9	0.0	0.0	n/a	n/a
Happy Jack PPA	15	4	0.0	0.0	n/a	n/a
Silver Sage PPA	20	6	0.0	0.0	n/a	n/a
BHP Wind PPA	12	4	0.0	0.0	n/a	n/a
Fall River Solar	80	9	0.0	0.0	n/a	n/a
Colstrip PPA	50	50	n/a	n/a	n/a	n/a

Table 07-23. Black Hills Power Unit Modeling Data

Nameplate capacity is considered to be equivalent to rated capacity. The summer capacity is considered dependable capacity. The annual availability depends on the timing of major overhauls as well as actual forced outages.

Joint Modeling Resources

The joint modeling performed in the IRP assumes all Cheyenne Light and Black Hills Power resources are available to serve the combined system load. While this simplification allows informative modeling, it does not fully account for facility ownership, existing contract, regulatory, or current transmission arrangements which may limit full utilization of resources to serve combined load. Currently Cheyenne Light and Black Hills Power are independently required to provide sufficient resources to meet forecasted peak demand plus planning reserves.

CANDIDATE RESOURCE OPTIONS

Conventional resources and renewable energy resources were analyzed in the evaluation of the resource options for the IRP. All capital cost estimates used in the modeling are order-of-magnitude overnight estimates. All estimates are based on an engineering, procurement, and construction method of contracting. These 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 (for fuel, water, and other resources) and end at the high side of the generator step-up transformer.

Fuel-Fired Resources

The IRP considered simple cycle and combined cycle CTs—both fired by natural gas—as supply-side resource options in its modeling.

The natural gas-fired resources for Cheyenne Light were assumed to be built in the Cheyenne area at a brownfield site where existing infrastructure could be shared with the new facilities. The natural gas-fired resources for Black Hills Power were assumed to be built in the Gillette and Rapid City areas at greenfield sites; however, the Gillette area would have some existing infrastructure that could be shared with the new facilities.

Performance assumptions and cost values for modeling conventional resources were taken from the Busbar Cost Study conducted by Black & Veatch.[45]

Simple Cycle Combustion Turbines

Cheyenne Light and Black Hills power use their simple cycle CTs for peaking and reserves because of their relatively low capital costs, higher full-load heat rate, and higher cost of fuel when compared to conventional baseload capacity. The simple cycle CTs also have quick-start and black-start capabilities.

45 See Appendix D: Busbar Cost Study.

In this analysis, technology options modeled for simple cycle CTs included LMS 100 (an aeroderivative turbine) and a LM6000 PF+. Table 07-24 lists the assumptions used to model each 1x0 CT option.

Assumption	LMS 100	LM6000 PF+
Earliest Feasible Installation	2023	2023
Summer Capacity (Net MW)	91	42
Full Load Heat Rate (Btu/kWh)	8,750	9,400
Forced Outage Rate (%)	2.5	2.5
Maintenance Outage Rate (%)	1.7	1.7
CO_2 Emission Rate (lb/MWh)	1,040	1,110
Fixed O&M (2021 $/kW-year)	29.56	60.87
Variable O&M (2021 $/MWh)	0.90	1.00
Capital Cost (2021 $/kW)	1,082	1,249

Table 07-24. Simple Cycle CT Modeling Assumptions

Combined Cycle Combustion Turbines

Assumptions for three different combined cycle configurations were included in the modeling: 1x1 CC, 2x1 CC, and 3x1 CC. The 1x1 CC consists of one gas turbine generator, one steam turbine generator, and one HRSG. The 2x1 CC configuration has two gas turbine-generators and two HRSGs that supply steam through a common header to a separate single steam turbine-generator. The 3x1 CC configuration has three gas turbine generators and three HRSGs that supply steam through a common header to a separate single steam turbine-generator.

Table 07-25 lists the assumptions for the 1x1, 2x1 (one specifically sited at CPGS), and 3x1 combined cycle CT configurations.

Assumption	1x1	2x1	2x1 at CPGS	3x1
Earliest Feasible Installation	2023	2023	2023	2023
Summer Capacity (Net MW)	73	111	112	167
Full Load Heat Rate (Btu/kWh)	7,850	7,050	7,050	7,050
Forced Outage Rate (%)	1.6	1.6	1.6	1.6
Maintenance Outage Rate (%)	1.1	1.1	1.1	1.1
CO_2 Emission Rate (lb/MWh)	940	840	840	840
Fixed O&M (2021 $/kW-year)	89.24	65.73	65.73	50.43
Variable O&M (2021 $/MWh)	1.10	1.10	1.10	1.00
Capital Cost (2021 $/kW)	1,318	1,455	1,442	1,380

Table 07-25. Combined Cycle CT Modeling Assumptions

In addition, one large, combined cycle option—the 1x1 7HA.02 CT—was included in the modeling. This unit assumed a twenty five percent ownership of a hypothetical partnership opportunity with another utility. The cost-benefit of being able to capture economies of scale through co-ownership are worthwhile to explore. Black Hills has been able to enter into this type of arrangements in the past when the opportunities are available. For example, the Wyodak coal-fired generating facility is jointly owned by PacifiCorp (80 percent) and Black Hills Power (20 percent). This option is assumed to be built off-system and includes estimated transmission costs to deliver the energy.

Table 07-26 lists the assumptions for the 7HA.02 combined cycle CT. These values are representative of the twenty five percent ownership.

Assumption	1x1
Earliest Feasible Installation	2023
Summer Capacity (Net MW)	111
Full Load Heat Rate (Btu/kWh)	6,300
Forced Outage Rate (%)	1.6
Maintenance Outage Rate (%)	1.1
CO_2 Emission Rate (lb/MWh)	750
Fixed O&M (2021 $/kW-year)	28.92
Variable O&M (2021 $/MWh)	0.80
Capital Cost (2021 $/kW)	791

Table 07-26. 7HA.02 Combined Cycle CT Modeling Assumptions

Renewable Resources

The renewable energy resource technologies that were modeled in the IRP include photovoltaic (PV) solar and wind. Data for performance and cost assumptions for solar and wind technology were obtained from the Busbar Cost Analysis completed by Black & Veatch.[46]

Integration costs and accredited capacity values were obtained from the Variable Energy Resource (VER) analysis completed by HAPG.[47] The fixed energy profiles for wind and solar resources represent the expected generation levels in which half of the time actual generation would fall below expected levels, and half of the time actual generation would be above expected levels assuming no curtailments. The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand over time. These values are dependent on the underlying portfolio and are expected to decline as the penetration of resources of the same type increases. For the purposes of portfolio selection, Black Hills Power developed capacity-contribution values specific to three wind profiles and three solar profiles used for proxy resources. In addition, Black Hills Power developed contribution values for three levels (50 MW, 100 MW, and 200 MW) of wind and solar penetration. Black Hills Power also

46 See Appendix D: Busbar Cost Study.

47 See Appendix F: Variable Energy Resource Integration Report.

developed capacity-contribution values for the 100 MW solar facility when combined with lithium-ion battery storage with three maximum output levels (20 MW, 40 MW, and 60 MW) assuming a four-hour battery storage duration.

In addition to integration costs and accredited capacity values, the VER study assessed the need for additional flexible capacity to integrate additional variable energy resources. A fundamental need when integrating variable energy resources on a system is to have sufficiently flexible capacity or load to allow for adjustments for unpredicted increases or decreases in variable energy generation levels, without creating reliability problems or unacceptable levels of imbalance energy. HAPG used a methodology originally developed by CAISO to assess each utility's flexible capacity requirements. Based on HAPG's analysis, flexible capacity costs were added for Cheyenne Light portfolios with more than 100 MW and Black Hills Power portfolios with more than 200 MW of variable energy resources. The cost of flexible generation is based on the cost of an LM6000 from the Black & Veatch busbar study.

PV Solar

The IRP modeling selects among three sizes of PV solar facilities: 50 MW, 100 MW, and 200 MW. Modeled PV solar assumes ownership at a relatively flat site that requires minimal grading and vegetation removal. Recent legislation related to investment tax credit levels for projects that commence construction after December 31, 2021 were included in the development of the PV solar cost assumptions.

Table 07-27 lists the modeling assumptions for solar PV facilities.

Assumption	50 MW	100 MW	200 MW
Earliest Feasible Installation	2023	2023	2023
Integration Cost ($/kW/Mo)	0.205	0.205	0.205
Capacity Factor (%)	26	24	28
Accreditable Capacity (%)	11	9	4
Fixed O&M (2021 $/kW-year)	0.00	0.00	0.00
Variable O&M (2021 $/MWh)	0.00	0.00	0.00
Capital Cost (2021 $/kW)	1,164	1,124	1,101

Table 07-27. Photovoltaic Solar Modeling Performance Assumptions

Wind

As with solar PV, the IRP modeling selects among three sizes of wind facilities: 50 MW, 100 MW, and 200 MW. All options assume ownership at a greenfield site.

Table 07-28 lists the modeling assumptions for wind facilities.

Assumption	50 MW	100 MW	200 MW
Earliest Feasible Installation	2023	2023	2023
Integration Cost ($/kW/Mo)	0.303	0.303	0.303
Capacity Factor (%)	45	40	43
Accreditable Capacity (%)	29	23	15
Fixed O&M (2021 $/kW-year)	0.00	0.00	0.00
Variable O&M (2021 $/MWh)	0.00	0.00	0.00
Capital Cost (2021 $/kW)	1,144	1,142	1,125

Table 07-28. Wind Modeling Assumptions

Battery Energy Storage System

Battery energy storage systems are distinguished from other resources by the following three attributes:

- Energy take: generation or extraction of energy from a storage reservoir
- Energy return: energy used to fill (or charge) a storage reservoir
- Storage cycle efficiency: an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle

Modeling battery storage resources requires specification of the size of the storage reservoir, defined in MWh. HAPG's Portfolio Optimization (PO) model dispatches a battery storage resource to optimize energy used by the resource subject to constraints, such as storage-cycle efficiency, the daily balance of take and return energy, and fuel costs (for example, the cost of natural gas for expanding air with gas turbine expanders). To determine the least-cost resource expansion plan, the PO model accounts for conventional generation system performance and cost characteristics of the battery storage resource, including capital cost, size of the storage and time to fill the storage, heat rate (if fuel is used), operating and maintenance cost, minimum capacity, and maximum capacity. Because they are energy-limited, a battery storage resource may not be able to cover the entirety of an extended outage.

HAPG's Fall 2020 Reference Case included battery storage modeled as pure arbitrage. The battery storage modeling looks for the four lowest-priced hours in a day to charge and the highest-priced hours to discharge. The model then strikes on those hours if there is a large enough price spread. battery storage can shave peak load. In general, battery storage can most economically be discharged during the highest priced peak hours. The modeled battery storage options used an algorithm that estimates marginal costs to determine economic charging and discharging schedules.

The IRP modeling selects among three sizes of four-hour duration battery storage options: 10 MW, 30 MW, and 100 MW. All stand-alone options assume ownership at a greenfield site.

Assumption	10 MW	30 MW	100 MW
Earliest Feasible Installation	2023	2023	2023
Integration Cost	n/a	n/a	n/a
Accreditable Capacity (%)	90	74	49
Annual Forced Outage Hours	0.0274	0.0411	0.0822
Maintenance Outage Rate	0.0137	0.0205	0.0411
Fixed O&M (2021 $/kWh-year)	7.50	7.50	7.50
Variable O&M (2021 $/MWh)	0.00	0.00	0.00
Capital Cost (2021 $/kWh)	255	235	215

Table 07-29. Battery Storage Modeling Assumptions

PV Solar plus Battery Energy Storage Systems

The IRP modeling also included PV solar plus battery storage options as bundled pairs. The 50 MW solar was paired with the 10 MW battery storage option, the 100 MW solar was paired with the 30 MW battery storage, and the 200 MW solar was paired with the 60 MW battery storage. The operational parameters and costs were the same as standalone options. The only difference is that these options had to be built together and the solar charged the battery storage unit.

Neil Simpson Unit II Power Plant

The Neil Simpson Unit II power plant is reaching the end of design life in 2025. As resources age, it is important to consider the resource options available to ensure cost-effective, reliable service to customers. As such, the power plant was modeled for four options to address this aging asset: extending its life, converting it from coal to natural gas, decommissioning and demolishing it, and adding CCUS technology. The first three options were analyzed in depth by Black & Veatch.[48] Assumptions for the CCUS option were developed by Black & Veatch in the busbar study.[49]

48 The Black & Veatch reports appear in Appendix E: Neil Simpson Unit II Power Plant Studies.

49 A summary of the modeling appears in “Candidate Resource Options” in Chapter 5.

Table 07-30 lists the assumptions for modeling the various options related to the Neil Simpson II power plant.

Assumption	Neil Simpson II Life Extension	Neil Simpson II Coal to Gas Conversion	Neil Simpson II Retirement	Neil Simpson II Carbon Capture
Earliest Feasible Installation	2025	2025	2025	2025
Summer Capacity (Net MW)	80	80	0	68
Full Load Heat Rate (Btu/kWh)	12,577	12,139	n/a	15,089
Forced Outage Rate (%)	3	7.3	n/a	4.7
Maintenance Outage Rate (%)	Varies	2.6	n/a	1.9
CO_2 Emission Rate (lb/MWh)	2,790	1,391	n/a	362
Fixed O&M (2021 $/kW-year)	103.99	43.65	1.30	132.72
Variable O&M (2021 $/MWh)	1.40	1.55	n/a	8.00
Capital Cost (2021 $/kW)	2,050	102	19.34	6,256

Table 07-30. Neil Simpson II Modeling Assumptions

Wygen II Power Plant

The Wygen II power plant was selected for analysis of adding CCUS technology under the carbon capture scenario only. Cheyenne Light developed this scenario to investigate potential customer impacts of installing CCUS on one of its coal-fired units. Wygen II was selected because it is Cheyenne Light's only utility-owned coal-fired resource. In addition, carbon capture cost and unit performance impacts were developed as part of the busbar study performed by Black & Veatch and applied to Wygen II.

Table 07-31 lists the assumptions for modeling the carbon capture related to the Wygen II power plant.

Assumption	Wygen II Carbon Capture
Earliest Feasible Installation	2025
Summer Capacity (Net MW)	68
Full Load Heat Rate (Btu/kWh)	14,170
Forced Outage Rate (%)	4.7
Maintenance Outage Rate (%)	1.9
CO_2 Emission Rate (lb/MWh)	362
Fixed O&M (2021 $/kW-year)	129.44
Variable O&M (2021 $/MWh)	8.00
Capital Cost (2021 $/kW)	4,206

Table 07-31. Wygen II Modeling Assumptions

Existing Resource Conversion Alternatives

While generic resource options were included as a part of the IRP modeling, the option of converting certain existing resources was also evaluated. Two options were considered for converting the CPGS simple cycle CT to a 2x1 combined cycle CT: wet cooled and dry cooled. Dry cooled results in lower water consumption. In addition, converting the Ben French diesels to operate using natural gas was considered.

Table 07-32 lists the assumptions for modeling the various options to convert the CPGS combined cycle CT and Ben French Diesels.

Assumption	CPGS SCCT Conversion to CC 2x1 Wet	CPGS SCCT Conversion to CC 2x1 Dry	Ben French Diesel Conversion to Gas
Earliest Feasible Installation	2023	2023	2023
Summer Capacity (Net MW)	97	96	7.5
Full Load Heat Rate (Btu/kWh)	7,150	7,250	11,900
Forced Outage Rate (%)	1.6	1.6	4.3
Maintenance Outage Rate (%)	1.1	1.1	1.0
CO_2 Emission Rate (lb/MWh)	850	860	1,390
Fixed O&M (2021 $/kW-year)	70.13	71.84	80.88
Variable O&M (2021 $/MWh)	1.10	0.90	0.00
Capital Cost (2021 $/kW)	1,013	1,062	350

Table 07-32. CPGS Simple Cycle CT and Ben French Diesel Conversion Assumptions

Seasonal Firm Market Purchased Power

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 manage customer costs.

The IRP assumes Cheyenne Light and Black Hills Power will each be able to purchase seasonal firm market power. This measure can be used to cover peak demand shortfalls up to 50 MW per utility and is assumed to be available six days per week, sixteen hours per day (7 am to 11 pm), which is consistent with experience transacting with counterparties in the west. In addition, the NERC 2021 Summer Reliability Assessment and NERC 2020 Long-Term Reliability Assessment indicate sufficient capacity is available in the region.

The model is able to select the seasonal firm market power in 10 MW blocks, up to a total of 50 MW (five blocks) beginning 2021 through 2040. This seasonal firm market power is priced at HAPG WECC 2020 Fall Reference Case Palo Verde price forecast plus a 20 percent premium. 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.

Table 07-33 lists the price ranges of Palo Verde market area from the beginning and ending years of the planning period for the natural gas and environmental scenarios.

Scenario	Palo Verde 2021 Price ($/MWh)	Palo Verde 2040 Price ($/MWh)
Base Natural Gas	34.93	41.61
Low Natural Gas	29.62	30.55
High Natural Gas	40.57	52.00
Environmental	34.93	70.75

Table 07-33. Seasonal Firm Market Purchase Modeling Assumptions

Demand Response

Demand response (DR) options are not included in the IRP. In a recently conducted survey of large customers with loads greater than 2 MW, respondents expressed limited interest in participating in potential Cheyenne Light and Black Hills Power demand response programs. The responses indicated that a DR program should not be developed at this time.[50]

DR programs for residential and smaller commercial customers are investigated through potential studies which are conducted periodically. Cheyenne Light completed it most recent study in mid-2015; it focused on energy efficiency measures for developing the 2016–2018 energy efficiency plan. Cheyenne Light's next potential study will be conducted in 2023 and will estimate the technical, economic, and achievable potential at the measure-level for energy efficiency and DR within their service territory over a 2025–2028 planning horizon. The potential study will include budget and impact estimates for the subset of measures that fit these criteria.

Black Hills Power no longer has a DSM program.

RISK ANALYSIS

The risk analysis conducted for the IRP examined uncertainty under a variety of possible future conditions. Stochastic analysis and risk profile compilation were among the risk techniques examined.

Stochastic Analysis

HAPG's PO software includes a stochastic model to simulate volatility in electricity prices, fuel prices, and loads.[51] PO has a regression tool that uses historical data to calculate the stochastic properties of these variables, including their volatility, short-term mean-reversion, and the correlations among the random time-series. Monte Carlo simulation is then

50 The survey and a summary of the results are contained in Appendix O: Demand-Side Management Survey.

51 Described in Appendix N: 2021 IRP Modeling Summary.

performed, with sample random draws from specified distributions. The power simulation model uses these random paths to optimize commitment and dispatch along each random path. Also, the PO stochastic modeling framework allows the user to specify for each stochastic entity either a normal or lognormal distribution. Load was modeled with a normal distribution while the market prices, natural gas prices, and coal prices were modeled with a lognormal distribution.

Four different PO types are set as stochastic variables: load, economy energy price, natural gas price, and coal price. Stochastic runs were performed using 50 iterations in PO for the seven scenarios of Black Hills Power and seven scenarios for Cheyenne Light. The scenarios for each utility included base, environmental, high load, low load, high gas, low gas, and base battery storage.

Table 07-34 lists the short-term volatilities and mean reversion rates calculated by the modeling

Fuel	Short Term Volatility Rate	Short Term Mean Reversion Rate
Coal	0.084	0.345
Electric Price CO-West	0.199	0.291
Natural Gas Price: Cheyenne	0.112	0.102
Natural Gas Price: Rapid City	0.112	0.102
Natural Gas Price: Gillette	0.112	0.102

Table 07-34. Short-Term Volatilities

Table 07-35 list the standard deviation and time correlations.

Reversion	Cheyenne Light Load		Black Hills Power Load	
	June–September	October–May	June–September	October–May
Standard Deviation	12.637	14.456	9.721	10.921
Time Correlation	0.945	0.945	0.663	0.663

Table 07-35. Mean Reversion Rates

Table 07-36 list the calculated correlations between the variables. During the stochastic evaluations, the prices and associated uncertainties provide sufficient information about the market to allow for proper evaluation of alternatives. For example, high gas prices would generally result in high on-peak prices for market power.

Price	Electric Price CO-West
Natural Gas Price: Cheyenne	0.40
Natural Gas Price: Rapid City	0.40
Natural Gas Price: Gillette	0.40
Electric Price CO-West	1.00

Table 07-36. Commodity Correlations

In addition, using Strategic Planning's Stratified Monte Carlo sampling program, HAPG created 50 future scenarios for portfolio capital cost evaluation. Uncertainty draws were made for the capital cost of the resource additions in the portfolio evaluation. These capital cost draws were combined with the uncertainty draws from the PO runs.

Table 7-37 lists the uncertainties examined in the IRP that resulted in 50 future scenarios for price development and portfolio evaluation.

Uncertainty	Range Multiplier
Simple Cycle Capital Cost	0.9 – 1.15
Combined Cycle Capital Cost	0.9 – 1.15
Wind Capital Cost	0.9 – 1.15
Solar Capital Cost	0.9 – 1.15
Battery Storage Capital Cost	0.9 – 1.15
Cheyenne Load	0.39 – 1.53
Black Hills Power Load	0.39 – 1.53
Market Price	1.12 – 2.05
Natural Gas Price	0.34 – 2.80
Coal Price	0.92 – 1.41

Table 07-37. Uncertainty Variable Range Multipliers

Each scenario was designed to maintain a minimum 15 percent reserve margin. However, when exposed to demand uncertainty in the risk analysis, there are certain scenarios where the expansion plan did not meet the 15 percent reserve margin. Under base assumptions, each resource plan was designed to maintain a minimum 15 percent reserve margin, with the exception of the low load scenario (Figure 07-2). The low load scenario buildout was developed to meet low load assumptions in the Capacity Expansion plan. When the low load scenario is analyzed under base load assumptions in PO, a natural capacity shortfall occurs to maintain the 15 percent reserve margin.

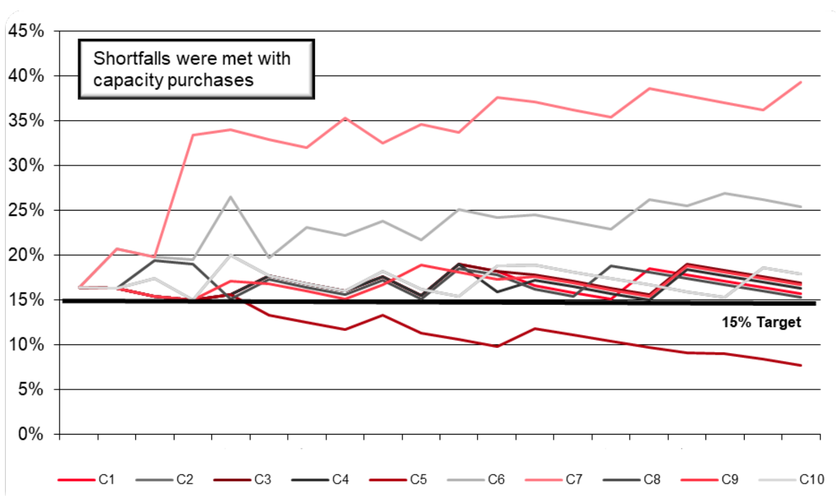


Figure 07-2. Cheyenne Light Scenarios Meeting the 15 Percent Required Reserve Margin

Figure 07-3 illustrates how the Black Hills Power scenarios meet the 15 percent reserve margin.

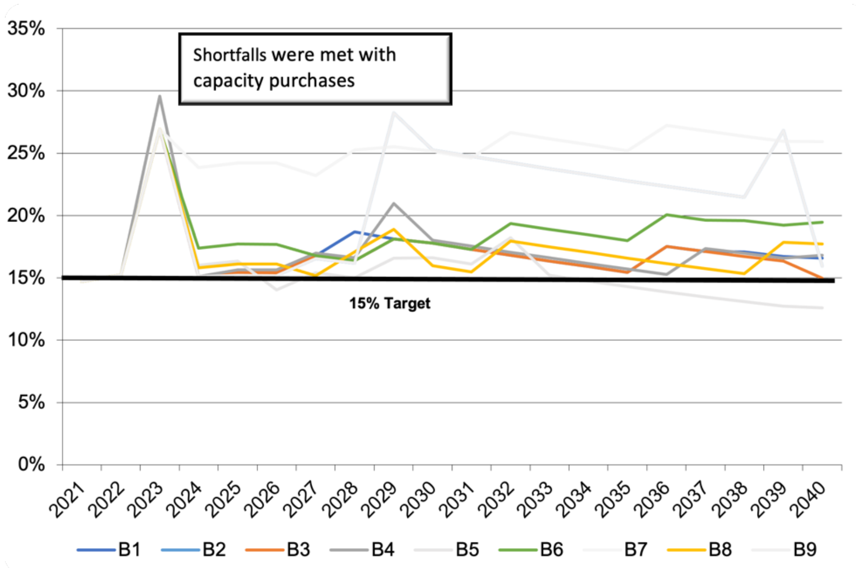


Figure 07-3. Black Hills Power Scenarios Meeting the 15 Percent Required Reserve Margin

Figure 07-4 illustrates how the joint scenarios meet the 15 percent reserve margin.

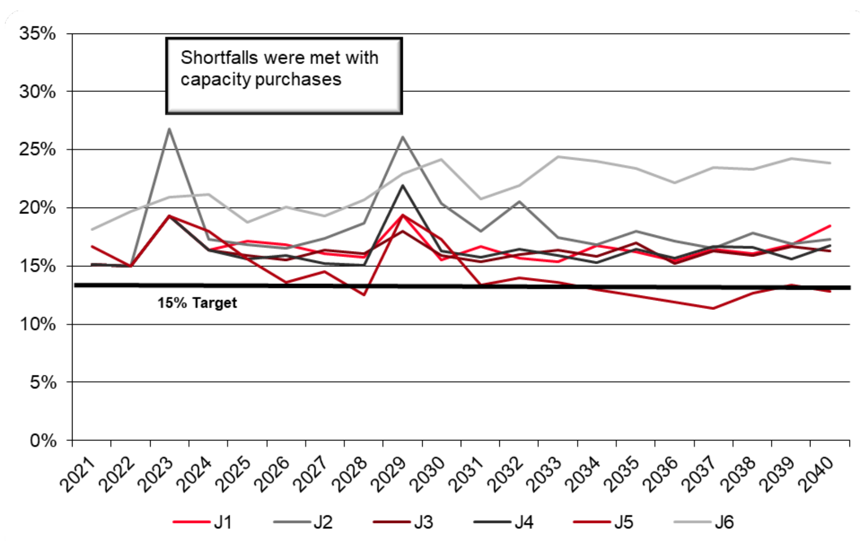


Figure 07-4. Joint Scenarios Meeting the 15 Percent Required Reserve Margin

When exposed to demand uncertainty in the stochastic process, there are certain scenarios where the resource plan would become reserve margin deficit. To address the deficits, EMA used the levelized cost of a new LM6000 combustion turbine as a proxy for the capacity market to meet the target.

08. PORTFOLIO ANALYSIS AND SELECTION

The Cheyenne Light preferred plan substantially relies on seasonal firm market purchases for capacity through the near-term need planning period. The Black Hills Power preferred plan consists of adding resources in the near-term need planning period and the conversion of Neil Simpson Unit II from coal to natural gas in 2025. Cheyenne Light's and Black Hills Power's preferred plans include the continued investigation of the customer value proposition of adding battery storage and investing in transmission to reduce long-term customer costs and capture organized market benefits.

LOAD AND RESOURCE BALANCE

The IRP analyzed three current portfolios: one for Cheyenne Light, one for Black Hills Power, and one joint portfolio for Cheyenne Light and Black Hills Power. Load and resource balances were prepared individually for Cheyenne Light and Black Hills Power to compare their annual peak demand with the capacity contribution of existing resources. A load and resource balance was also prepared for the utilities jointly assuming all resources were available to meet the combined peak demand.

The load and resource balances highlight the years in which forecasted demand exceeds resources, indicating a need for additional capacity. All three load and resource balances consider the 15 percent planning reserve margin requirement.

The load and resource balance for all three portfolios show capacity deficits during the near-term need planning period. These capacity deficits vary for each utility individually and jointly. The capacity deficit for Black Hills Power individually and for both utilities jointly must be met by adding physical resources. The capacity deficit for Cheyenne Light can be met through seasonal firm market purchases.[52]

Cheyenne Light Load and Resource Balance

Cheyenne Light's load and resource balance for the near-term need planning period includes the base load forecast and existing resources. Table 08-1 contains these requirements.

Cheyenne Light Load and Resource Balance						
Resource (MW)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Peak Demand	217.0	226.0	227.0	228.0	227.0	231.0
DSM	(1.6)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)
Net Peak Demand	215.0	224.0	225.0	226.0	225.0	229.0
CPGS Simple Cycle CT	37.0	37.0	37.0	37.0	37.0	37.0
CPGS Combined Cycle CT	40.0	40.0	40.0	40.0	40.0	40.0
Wygen II	90.0	90.0	90.0	90.0	90.0	90.0
Corriedale Wind	5.8	5.8	5.8	5.8	5.8	5.8
Wygen I PPA	60.0	60.0	60.0	60.0	60.0	60.0
Happy Jack PPA	4.4	4.4	4.4	4.4	4.4	4.4
Silver Sage PPA	2.9	2.9	2.9	2.9	2.9	2.9
Total Generation	240.0	240.0	240.0	240.0	240.0	240.0
15% Reserve Margin	32.0	34.0	34.0	34.0	34.0	34.0
Total Capacity Requirement (Peak plus Reserves)	247.0	257.0	259.0	260.0	259.0	264.0
Total Resources minus Total Capacity Requirement	(7.0)	(17.0)	(19.0)	(20.0)	(19.0)	(24.0)
Percent (Deficit)	(3%)	(7%)	(7%)	(8%)	(7%)	(9%)

Table 08-1. Cheyenne Light Near-Term Need Load and Resource Balance

52 Appendix J: Load and Resource Balance 2021–2040 contains the load and resource balance amounts for Cheyenne Light individually, Black Hills Power individually, and for both utilities jointly for the entire 20-year planning period.

Figure 08-1 illustrates the total megawatts from Cheyenne Light's existing resources in comparison to the capacity planning requirement of peak demand plus the 15 percent reserve planning margin over the course of the planning period. The gap indicates power that must be obtained through either market purchases or additional resources.

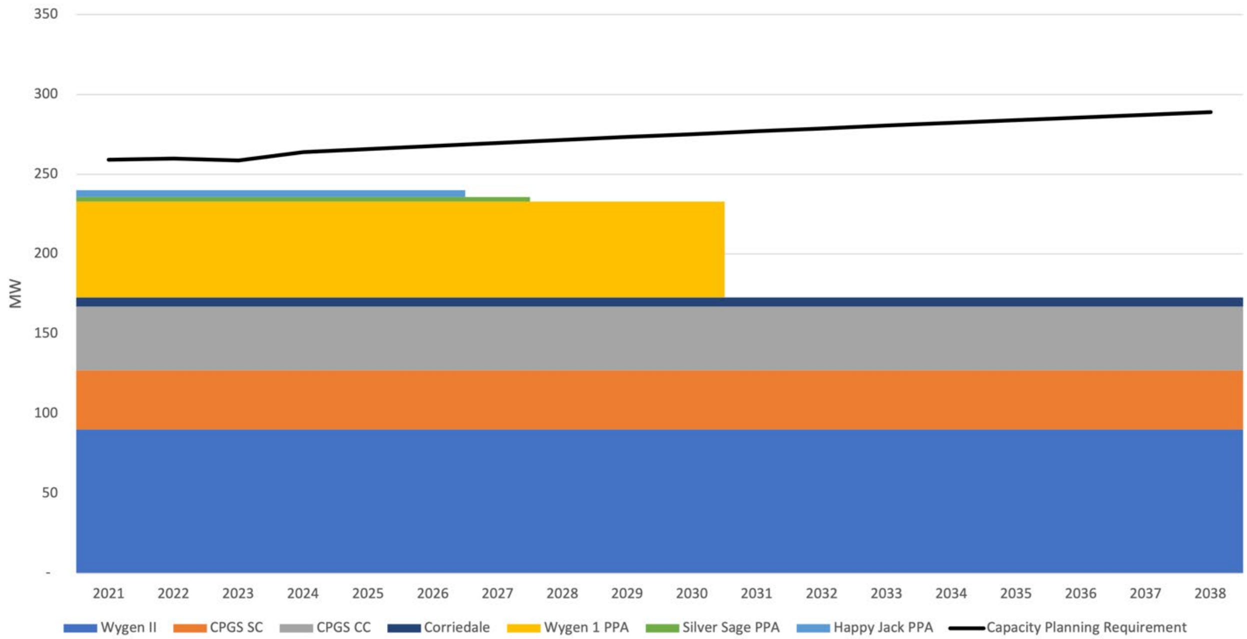


Figure 08-1. Cheyenne Light Existing Resources Plus Resource Margin (2021–2040)

Black Hills Power Load and Resource Balance

Black Hills Power's load and resource balance for the near-term need planning period includes the base load forecast and existing resources. Table 08-2 contains these requirements.

Black Hills Power Load and Resource Balance						
Resource (MW)	2021	2022	2023	2024	2025	2026
Peak Demand	373.0	376.0	378.0	380.0	378.0	378.0
DSM	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)
Net Peak Demand	372.0	375.0	377.0	379.0	377.0	377.0
Ben French Diesels #1–5	10.0	10.0	10.0	10.0	10.0	10.0
Ben French SCCTs #1–4	72.0	72.0	72.0	72.0	72.0	72.0
Lange Simple Cycle CT	39.0	39.0	39.0	39.0	39.0	39.0
Neil Simpson Simple Cycle CT	39.0	39.0	39.0	39.0	39.0	39.0
Neil Simpson Unit II	80.0	80.0	80.0	80.0	80.0	80.0
CPGS Combined Cycle CT	55.0	55.0	55.0	55.0	55.0	55.0
Corriedale Wind	9.4	9.4	9.4	9.4	9.4	9.4
Wygen III	52.0	52.0	52.0	52.0	52.0	52.0
Wyodak	62.0	62.0	62.0	62.0	62.0	62.0
Colstrip PPA	50.0	50.0	50.0	n/a	n/a	n/a
Happy Jack PPA	4.4	4.4	4.4	4.4	4.4	4.4
Silver Sage PPA	5.8	5.8	5.8	5.8	5.8	5.8
Wind PPA	3.5	3.5	3.5	3.5	3.5	3.5
Fall River PPA	n/a	n/a	8.8	8.8	8.7	8.7
Total Generation	412.0	410.0	439.0	388.0	387.0	386.0
15% Reserve Margin	76.0	76.0	67.0	66.0	65.0	64.0
Total Capacity Requirement (Peak plus Reserves)	448.0	450.0	443.0	445.0	442.0	441.0
Total Resources minus Total Capacity Requirement	(36.0)	(41.0)	(5.0)	(58.0)	(55.0)	(55.0)
Percent (Deficit)	(8%)	(9%)	(1%)	(13%)	(13%)	(13%)

Table 08-2. Black Hills Power Near-Term Need Load and Resource Balance

Figure 08-2 illustrates the total megawatts from Black Hills Power's existing resources in comparison to the capacity planning requirement of peak demand plus the 15 percent reserve planning margin over the course of the planning period. The gap indicates power that must be obtained through either market purchases or additional resources.

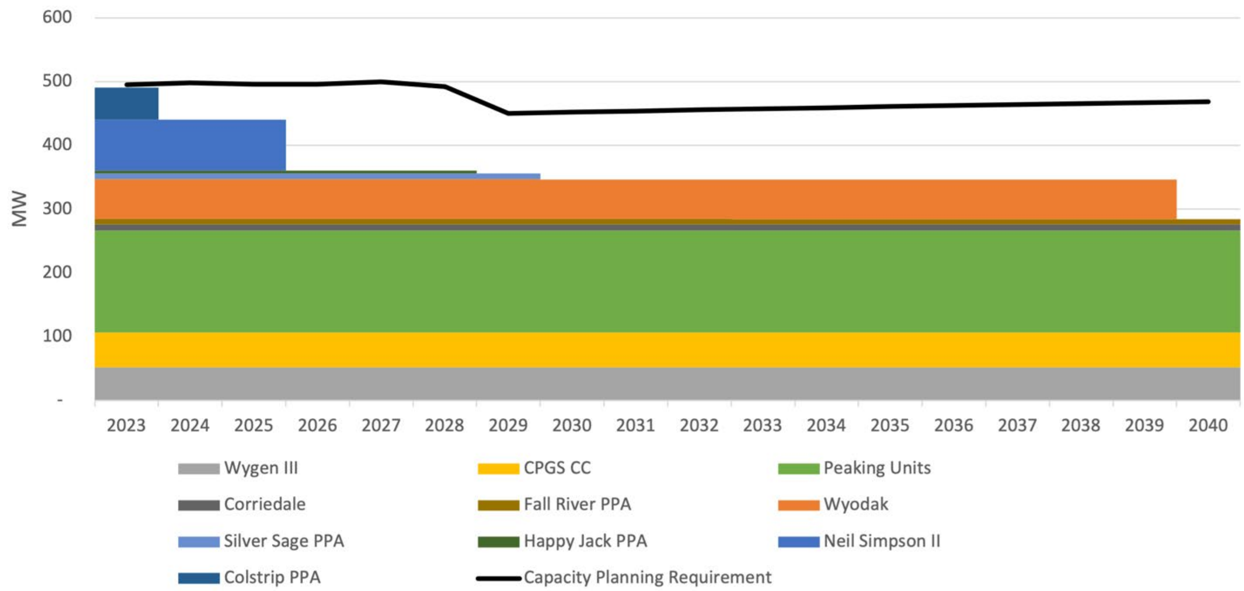


Figure 8-02. Black Hills Power Existing Resources Plus Reserve Margin (2021–2040)

Cheyenne Light and Black Hills Power Joint Load and Resource Balance

Table 08-03 contains the joint utility load and resource balance requirements for the near-term need planning period, including the base load forecast and existing resources.

Cheyenne Light and Black Hills Power Joint Load and Resource Balance						
Resource (MW)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Peak Demand	546.0	546.0	547.0	570.0	580.0	565.0
DSM	(2.4)	(2.9)	(2.9)	(2.9)	(2.9)	(2.9)
Net Peak Demand	543.0	543.0	544.0	567.0	577.0	562.0
Cheyenne Light Generation						
CPGS Simple Cycle CT	37.0	37.0	37.0	37.0	37.0	37.0
CPGS Combined Cycle CT	40.0	40.0	40.0	40.0	40.0	40.0
Wygen II	90.0	90.0	90.0	90.0	90.0	90.0
Corriedale Wind	5.8	5.8	5.8.0	5.8	5.8	5.8
Wygen I PPA	60.0	60.0	60.0	60.0	60.0	60.0
Happy Jack PPA	4.4	4.4	4.4	4.4	4.4	4.4
Silver Sage PPA	2.9	2.9	2.9	2.9	2.9	2.9
Black Hills Power Generation						
Ben French Diesels #1–5	10.0	10.0	10.0	10.0	10.0	10.0
Ben French SCCTs #1–4	72.0	72.0	72.0	72.0	72.0	72.0
Lange Simple Cycle CT	39.0	39.0	39.0	39.0	39.0	39.0
Neil Simpson Simple Cycle CT	39.0	39.0	39.0	39.0	39.0	39.0
Neil Simpson Unit II	80.0	80.0	80.0	80.0	80.0	80.0
CPGS Combined Cycle CT	55.0	55.0	55.0	55.0	55.0	55.0
Corriedale Wind	9.4	9.4	9.4	9.4	9.4	9.4
Wygen III	52.0	52.0	52.0	52.0	52.0	52.0
Wyodak	62.0	62.0	62.0	62.0	62.0	62.0
Colstrip PPA	50.0	50.0	50.0	n/a	n/a	n/a
Happy Jack PPA	4.4	4.4	4.4	4.4.0	4.4	4.4
Silver Sage PPA	5.8	5.8	5.8	5.8.0	5.8	5.8
Wind PPA	3.5	3.5	3.5	3.5.0	3.5	3.5
Fall River PPA	n/a	n/a	8.8	8.8.0	8.7	8.7
Total Generation	652.0	650.0	679.0	628.0	627.0	626.0
15% Reserve Margin	102.0	101.0	92.0	94.0	95.0	92.0
Total Capacity Requirement (Peak plus Reserves)	645.0	644.0	636.0	661.0	672.0	654.0
Total Resources minus Total Capacity Requirement	7.0	6.0	43.0	(34.0)	(45.0)	(28.0)
Percent Excess/(Deficit)	1%	1%	7%	(5%)	(7%)	(4%)

Table 08-3. Cheyenne Light and Black Hills Power Joint Near-Term Need Load and Resource Balance

The joint system peak demand forecast is lower than the sum of the individual utilities as Cheyenne Light and Black Hills Power do not peak at the same hour of the year. Aggregating the two utilities into the joint forecast at the hourly level appropriately reflects the diversity in load between the two utilities. Adding planning reserve margin and comparing to existing resources results in different resource deficits because of the lower peak demand forecast.

BASE PLAN ANALYSIS

The IRP 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 IRP refers to this as the Base Plan.

The Capacity Expansion model developed the Base Plans for each utility 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.
- No carbon tax applied during the planning period.
- Base peak demand and annual energy forecasts.[53]
- Base natural gas, coal, and economy energy forecasts.[54]
- Seasonal firm market purchases up to 50 MW per utility and up to 100 MW for the joint utility plan.
- Conventional and renewable energy resource options.[55]

53 Described in "Base Peak Demand and Annual Energy Forecasts" in Chapter 7: Modeling Approach and Assumptions.

54 Described in "Fuel Price Forecasts" in Chapter 7: Modeling Approach and Assumptions.

55 Described in "Candidate Resource Options" in Chapter 5: Generation Resources.

SCENARIO ANALYSIS

The Capacity Expansion module analyzed nine scenarios to derive candidate resource portfolios. The scenarios include variables that would create the largest impact on cost variability and risk to result in unique resource portfolios.

For reference, the scenarios are numbered 1 through 9.

The Capacity Expansion module ran all nine scenarios for Cheyenne Light; it ran scenarios 1 through 8 for Black Hills Power, and scenarios 1 through 6 for the joint plan.

This resulted in nine candidate resource portfolios developed for Cheyenne Light, labeled C1 through C9.

The eight resultant candidate resource portfolios developed for Black Hills Power are labeled B1 through B8.

The six resultant candidate resource portfolios developed for Cheyenne Light and Black Hills Power jointly are labeled J1 through J6.

A brief description of each of the nine scenarios and their variables follows.[56]

1. Base Plan
   - Assumed variables as described in "Base Plan Analysis" on page 08-8.
   - Developed candidate resource portfolios: B1, C1, J1.
2. Environmental Scenario
   - Investigated the impact a CO_2 tax would have on the resource portfolio.
   - Replaced the base economy energy price forecast with the environmental economy energy forecast.
   - Added CO_2 emissions prices from HAPG's CO_2 tax scenario.
   - Assumed all other modeling variables as described in "Base Plan Analysis".
   - Developed candidate resource portfolios: B2, C2, J2.

56 Chapter 7: Modeling Approach and Assumptions includes the "Fuel Price Forecasts" and "Load Forecasts" which describes the energy price forecasts and load forecasts used in all scenarios.

3. Low Gas Scenario
   - Investigated the impact extended low natural gas prices would have on the 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 "Base Plan Analysis".
   - Developed candidate resource portfolios: B3, C3, J3.
4. High Gas Scenario
   - Investigated the impact high natural gas prices would have on the 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 "Base Plan Analysis".
   - Developed candidate resource portfolios: B4, C4, J4.
5. Low Load Scenario
   - Investigated the impact lower than forecasted load growth would have on the resource portfolio.
   - Replaced the base load forecast with the low load forecast.
   - Assumed all other modeling variables as described in "Base Plan Analysis".
   - Developed candidate resource portfolios: B5, C5, J5
6. High Load Scenario
   - Investigated the impact higher than forecasted load growth would have on the resource portfolio.
   - Replaced the base load forecast with the high load forecast.
   - Assumed all other modeling variables as described in "Base Plan Analysis".
   - Developed candidate resource portfolios: B6, C6, J6.
7. High-High Load Scenario
   - Investigated the impact higher than forecasted load growth, with an additional 25 MW step load starting in 2024, would have on the resource portfolio.
   - Replaced the base load forecast with the high-high load forecast.
   - Assumed all other modeling variables as described in "Base Plan Analysis."
   - Developed candidate resource portfolios: B7, C7.
8. Base Battery Energy Storage System (BESS) Scenario
   - Investigated the impact adding battery storage in 2023 would have on the resource portfolio.
   - Added 10 MW of four-hour battery storage in 2023.
   - Assumed all other modeling variables as described in "Base Plan Analysis".
   - Developed candidate resource portfolios: B8, C8.

9. Carbon Capture scenario for Cheyenne Light
   - Investigated the impact adding carbon capture to Wygen II would have on the resource portfolio.
   - Added carbon capture to Wygen II in 2025.
   - Assumed all other modeling variables as described in “Base Plan Analysis”.
   - Developed candidate resource Portfolio: C9.

Table 08-4 summarizes the assumption variables used for each scenario and lists the resulting portfolios from modeling.

Scenario	Load Growth	Economy Energy Forecast	Natural Gas Forecast	CO_2 Tax	Resource Selection	Resulting Portfolios
1	Median	Median	Median	None	Economic	B1 C1 J1
2	Median	Median	Median	Included	Economic	B2 C2 J2
3	Median	Low	Low	None	Economic	B3 C3 J3
4	Median	High	High	None	Economic	B4 C4 J4
5	Low	Median	Median	None	Economic	B5 C5 J5
6	High	Median	Median	None	Economic	B6 C6 J6
7	High-High	Median	Median	None	Economic	B7 C7
8	Median	Median	Median	None	10 MW 4-hour BESS	B8 C8
9	Median	Median	Median	None	Carbon Capture	C9

Table 08-4. Scenario Characteristics Summary

Scenarios 2 through 7 change the assumptions that are likely to influence the size, type, and timing of resource addition, and investigate their resultant impact. Modeling the scenarios evaluates the risk exposure to Cheyenne Light and Black Hills Power, individually and jointly because of these future uncertainties.[57]

Scenario 8 investigates the impact of adding battery storage to Cheyenne Light’s and Black Hills Power’s resource portfolios. As more variable renewable energy is added to the grid, the need to investigate the customer benefits of battery storage becomes more pressing. Energy storage can help smooth the flow of power to the grid and shift energy from times of high generation to times of high consumption.

Scenario 9 provides insight into what additional resources would need to be added to Cheyenne Light’s resource portfolio as a result of adding carbon capture to Wygen II.

As discussed in Chapter 3, House Bill 200 requires the Wyoming Commission to establish energy portfolio standards requiring a specified percentage of electricity to be dispatchable, reliable, and low carbon by 2030. Low-carbon electricity is generated using CCUS technology that results in less than 650 pounds of CO_2 emissions per MWh of electricity generated. The bill also requires the Wyoming Commission to set intermediate energy production standards

57 The electric market prices, natural gas prices, and CO_2 tax cost forecasts used to model the scenarios are detailed in confidential schedules in Appendix H: Price and Cost Forecasts.

and require public utilities to demonstrate in each IRP the steps the utility is taking to achieve those standards.

Even though specific standards have not yet been established, Cheyenne Light developed Scenario 9 to investigate potential customer impacts of installing CCUS on one of its coal-fired units. Wygen II was chosen because it is Cheyenne Light's only utility-owned coal-fired resource. In addition, carbon capture cost and unit performance impacts were developed as part of the busbar study performed by Black & Veatch and applied to Wygen II for Scenario 9.

Incremental carbon capture costs include installing and operating new carbon capture equipment. Unit performance impacts include a reduction in net generation output because of the auxiliary power consumed by the carbon capture equipment. Costs included in this analysis are those directly associated with capturing the carbon at the generating facility. No incremental costs associated with the compression, transportation, sale, use, or sequestrations of the captured carbon were analyzed. Similarly, no incremental revenues or tax incentives associated with the sale, use, or sequestration of the captured carbon were analyzed. These costs and revenues were excluded because of the high levels of uncertainty.

House Bill 200 is also applicable to Black Hills Power, however, the IRP does not include a specific scenario designed to analyze installation of CCUS for a Black Hills Power generation resource. Instead, Black Hills Power included the option to add carbon capture to Neil Simpson II in all scenarios. This option was not selected by the Capacity Expansion model as the most economic resource for customers in any scenario. Further, House Bill 200 is not expected to impact Black Hills Power during the IRP near-term need planning period due to the conversion of Neil Simpson II to natural gas.

Cheyenne Light and Black Hills Power will continue to monitor the implementation of House Bill 200 and include CCUS analysis in future IRPs as appropriate.

Cheyenne Light Resource Portfolios

The resource portfolios for scenarios C1 and C3 through C6 do not add any new generating resources during the near-term need planning period. Portfolio C2 adds a new wind resource in 2023 and a new solar resource in 2024. Portfolio C7 adds a new wind resource in 2024. Portfolio C8 adds a battery storage resource in 2023. Portfolio 9 adds carbon capture technology to Wygen II in 2025 and a natural gas and a solar resource in 2025.

Table 08-5 contains the Capacity Expansion modeling results for the Cheyenne Light scenarios.

Cheyenne Light Resource Portfolios—Scenario Analysis									
Year	Base Plan (C1)	Environmental Scenario (C2)	Low Gas Scenario (C3)	High Gas Scenario (C4)	Low Load Scenario (C5)	High Load Scenario (C6)	High-High Load Scenario (C7)	Base BESS Scenario (C8)	Carbon Capture Scenario (C9)
2021									
2022									
2023		Wind 50 MW						BESS 10 MW	
2024		Solar 50 MW					Wind 50 MW		
2025									Solar 50 MW Wygen 2 CCUS
2026						Wind 50 MW	BESS 10 MW Wind 50 MW		Wind 50 MW
2027									
2028									
2029		Wind 50 MW							
2030									
2031									
2032				Wind 50 MW			Wind 50 MW		
2033	CT 40 MW Wind 100 MW	CT 40 MW	CT 90 MW	CT 40 MW Wind 100 MW	CT 40 MW Wind 50 MW	CT 90 MW Wind 50 MW	CT 90 MW	CT 40 MW Wind 100 MW	CT 90 MW Wind 50 MW
2034									
2035									
2036									
2037									
2038					Wind 50 MW	Solar 50 MW			
2039							Wind 50 MW		
2040									

Table 08-5. Cheyenne Light Resource Portfolios—Scenario Analysis

The Cheyenne Light resource portfolios rely on seasonal firm market purchases to varying degrees during both the near-term need and full planning periods. Table 08-6 contains the amount of seasonal firm market purchases included in each Cheyenne Light scenario.

Cheyenne Light Resource Portfolios—Seasonal Firm Market Purchases (MW)									
Year	Base Plan (C1)	Environmental Scenario (C2)	Low Gas Scenario (C3)	High Gas Scenario (C4)	Low Load Scenario (C5)	High Load Scenario (C6)	High-High Load Scenario (C7)	Base BESS Scenario (C8)	Carbon Capture Scenario (C9)
2021	10	10	10	10	10	10	10	10	10
2022	20	20	20	20	20	30	30	20	20
2023	20	10	20	20	20	30	30	20	20
2024	20	–	20	20	20	30	50	20	20
2025	20	–	20	20	20	30	50	10	40
2026	30	10	30	30	20	20	30	20	30
2027	30	10	30	30	20	30	30	20	30
2028	30	10	30	30	20	30	40	20	30
2029	40	10	40	40	30	40	40	30	40
2030	40	10	40	40	30	40	50	30	50
2031	50	10	50	50	30	50	50	40	50
2032	50	20	50	30	30	50	50	40	50
2033	40	40	20	30	40	10	20	30	10
2034	40	40	20	30	40	10	20	30	10
2035	40	40	20	30	40	10	20	40	10
2036	50	40	20	30	40	20	30	40	10
2037	50	40	30	40	40	20	30	40	20
2038	50	40	30	40	30	20	30	40	20
2039	50	50	30	40	30	20	30	40	20
2040	50	50	30	40	30	20	40	40	20

Table 08-6. Cheyenne Light Resource Portfolios—Seasonal Firm Market Purchases

Black Hills Power Resource Portfolios

All eight Black Hills Power resource portfolios convert Neil Simpson Unit II from coal to natural gas in 2025. They also add new renewable generating resources during the near-term need planning period. While the renewable generation additions supply some accredited capacity to the load and resource balance, the primary driver of the energy additions is the low marginal cost energy they provide. Portfolio B8 also adds a battery storage in 2023.

Table 08-7 contains the Capacity Expansion modeling results for the Black Hills Power scenarios.

Black Hills Power Resource Portfolios—Scenario Analysis								
Year	Base Plan (B1)	Environmental Scenario (B2)	Low Gas Scenario (B3)	High Gas Scenario (B4)	Low Load Scenario (B5)	High Load Scenario (B6)	High-High Load Scenario (B7)	Base BESS Scenario (B8)
2021								
2022								
2023	Wind 50 MW	Wind 250 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	BESS 10 MW Solar 50 MW
2024	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Solar 50 MW	Wind 50 MW	Wind 150 MW Solar 50 MW	Wind 50 MW
2025	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW Solar 100 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW Solar 100 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW
2026								
2027								
2028								
2029								
2030					Wind 50 MW			
2031								
2032								Wind 50 MW
2033								
2034								
2035								
2036								
2037								
2038	Wind 50 MW					Wind 50 MW		
2039		Wind 100 MW						Wind 50 MW
2040	Wind 100 MW		Wind 150 MW	Wind 150 MW	Wind 100 MW	Wind 150 MW	Wind 150 MW BESS 10 MW	Wind 100 MW

Table 08-7. Black Hills Power Resource Portfolios—Scenario Analysis

The Black Hills Power resource portfolios rely on seasonal firm market purchases to varying degrees during both the near-term need and full planning periods. Table 08-8 contains the amount of seasonal firm market purchases included in each Black Hills Power scenario.

Black Hills Power Resource Portfolios—Seasonal Firm Market Purchases (MW)								
Year	Base Plan (B1)	Environmental Scenario (B2)	Low Gas Scenario (B3)	High Gas Scenario (B4)	Low Load Scenario (B5)	High Load Scenario (B6)	High-High Load Scenario (B7)	Base BESS Scenario (B8)
2021	50	50	50	50	50	50	50	50
2022	50	50	50	50	50	50	50	50
2023	50	20	50	50	50	50	50	40
2024	40	10	40	40	50	50	50	50
2025	40	–	40	30	50	50	50	30
2026	40	–	40	30	40	50	50	30
2027	50	10	50	40	50	50	50	40
2028	50	–	40	30	40	40	50	30
2029	–	–	–	–	–	–	–	–
2030	10	–	10	–	–	10	10	–
2031	10	–	10	–	–	10	10	–
2032	10	–	10	–	10	20	20	–
2033	10	–	10	–	–	20	20	–
2034	10	–	10	–	–	20	20	–
2035	10	–	10	–	–	20	20	10
2036	20	–	20	–	–	30	30	10
2037	20	–	20	10	–	30	30	10
2038	10	–	20	10	–	20	30	–
2039	10	–	20	10	–	20	30	–
2040	50	20	50	40	40	50	50	40

Table 08-8. Black Hills Power Resource Portfolios—Seasonal Firm Market Purchases

Joint Resource Portfolios

All six joint resource portfolios include converting Neil Simpson Unit II from coal to natural gas in 2025. Portfolios J1, J2, J4, J5, and J6 add new renewable generating resources during the near-term need planning period; portfolio J3 does not add any generating resources during this planning period.

Table 08-9 contains the Capacity Expansion modeling results for the Cheyenne Light and Black Hills Power joint scenarios.

Joint Resource Portfolios— Scenario Analysis						
Year	Base Plan (J1)	Environmental Scenario (J2)	Low Gas Scenario (J3)	High Gas Scenario (J4)	Low Load Scenario (J5)	High Load Scenario (J6)
2021						
2022						
2023		Wind 200 MW Solar 200 MW				
2024						
2025	NSII Coal to Gas 80 MW Solar 200 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW	NSII Coal to Gas 80 MW Solar 200 MW	NSII Coal to Gas 80 MW Solar 200 MW	NSII Coal to Gas 80 MW Solar 200 MW
2026				Wind 50 MW		
2027						
2028						
2029						
2030						
2031						Wind 50 MW
2032						Wind 50 MW
2033	Wind 100 MW			Wind 150 MW	Wind 100 MW	Wind 50 MW
2034	Wind 50 MW					Wind 50 MW
2035						
2036			Wind 50 MW			
2037					Wind 50 MW	
2038				Wind 50 MW		Wind 50 MW
2039						
2040	Wind 150 MW	BESS 10 MW	Wind 150 MW	Wind 100 MW	Wind 50 MW	Wind 150 MW

Table 08-9. Joint Plan Resource Portfolios—Scenario Analysis

The joint resource portfolios are similar to the individual utility resource portfolios in that Neil Simpson Unit II is converted from coal-fired to natural gas-fired in all scenarios. All scenarios, except J3, also add new renewable energy resources during the near-term need planning period. In addition, five out of nine Cheyenne Light resource portfolios do not add any resources during the near-term need planning period, which limits the ability of the utilities to benefit from economies of scale achieved through partnering on resource acquisitions. Because of these factors, a joint action plan was not developed.

The joint resource portfolios rely on seasonal firm market purchases to varying degrees during the near-term need and full planning periods. Table 08-10 contains the amount of seasonal firm market purchases included in each joint scenario.

Joint Resource Portfolios—Seasonal Firm Market Purchases (MW)						
Year	Base Plan (J1)	Environmental Scenario (J2)	Low Gas Scenario (J3)	High Gas Scenario (J4)	Low Load Scenario (J5)	High Load Scenario (J6)
2021	10	10	10	10	20	30
2022	10	10	10	10	10	40
2023	–	–	–	–	–	10
2024	50	10	50	50	60	80
2025	60	20	60	50	50	70
2026	40	–	40	20	20	60
2027	40	10	50	20	30	60
2028	10	–	20	–	–	50
2029	–	–	–	–	–	20
2030	10	–	20	–	20	60
2031	40	10	40	20	20	50
2032	10	–	20	–	–	20
2033	30	30	60	10	10	70
2034	20	30	60	10	10	60
2035	20	30	70	10	20	60
2036	70	80	100	60	60	100
2037	50	50	80	40	20	80
2038	50	60	80	30	30	70
2039	30	40	60	10	10	60
2040	60	90	90	50	60	90

Table 08-10. Joint Plan Resource Portfolios—Seasonal Firm Market Purchases

Present Value Revenue Requirements

Production cost modeling was performed on the twenty-three candidate resource portfolios established by the Capacity Expansion modeling to calculate the deterministic PVRR for each portfolio. The Production cost modeling used median assumptions for all input variables: load, natural gas price, economy energy price, and no CO_2 tax.

Figure 08-3 contains the PVRR for each Cheyenne Light resource portfolio.

Figure 08-3. Present Value Revenue Requirements for Cheyenne Light Resource Portfolios

Portfolio C3 is the least-cost portfolio based on the PVRR analysis. Portfolio C3, however, has a similar PVRR to Portfolios C1, C5, and C8, which is primarily a result of similar resource additions throughout the planning period. The PVRR for Portfolio C9 is significantly higher than the other portfolios indicating increased customer cost.

Figure 08-4 contains the PVRR for each Black Hills Power resource portfolio.

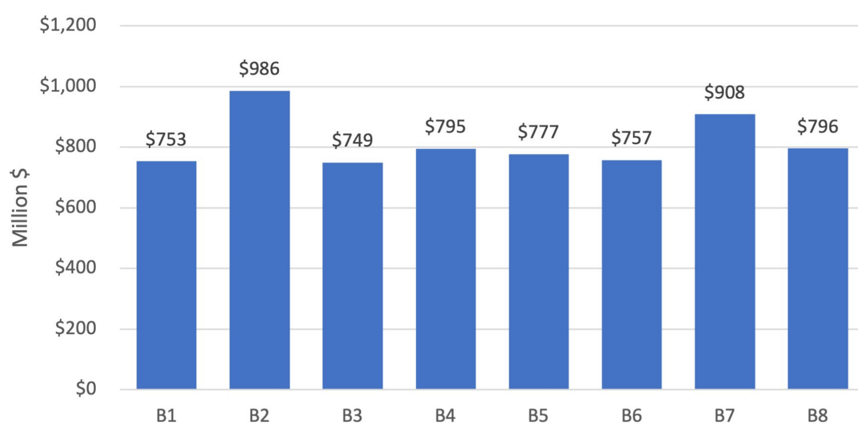


Figure 08-4. Present Value Revenue Requirements for Black Hills Power Resource Portfolios

Portfolio B3 is the lowest-cost portfolio based on the PVRR analysis. Portfolio B3, however, has a similar PVRR to Portfolios B1, B5, and B6, which is primarily a result of similar resource additions throughout the planning period.

The PVRR of adding battery storage in 2023 was determined in Portfolio 8. Battery storage presents the opportunity to create system and customer benefits. It can capture excess variable energy and store it until needed, manage the balance between supply and demand, shift load from on-peak to off-peak times, and be dispatched as a load or a resource almost instantaneously. Installing battery storage can also create a number of benefits to the transmission and distribution system.

The PVRR for adding battery storage to the Cheyenne Light system is similar to several other portfolios. The PVRR for adding battery storage to the Black Hills Power system is higher than other portfolios mainly because capacity expansion modeling chose the addition of a solar array in 2023 instead of wind; substituting wind would lower the PVRR. In both instances, the slightly higher PVRRs can be mitigated by increased benefits.

Figure 08-5 contains the PVRR for each of the joint resource portfolios.

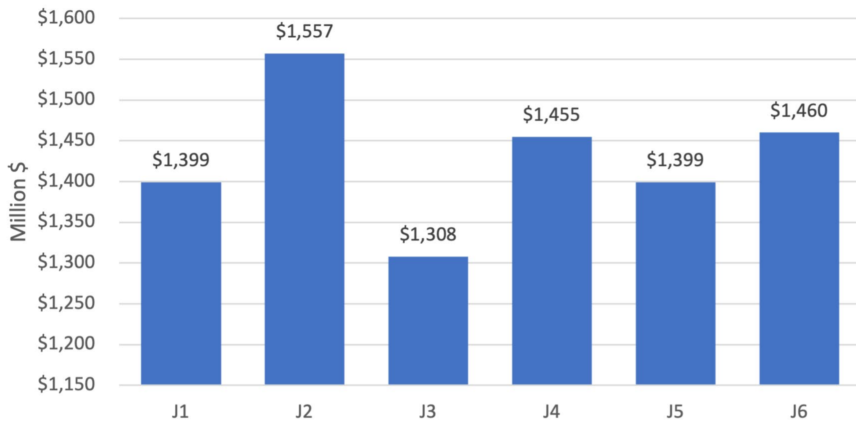


Figure 08-5. Present Value Revenue Requirements for Joint Resource Portfolios

Portfolio J3 has the lowest PVRR. While joint modeling is informative, Cheyenne Light and Black Hills Power are independently required to provide sufficient resources to meet forecasted peak demand plus planning reserves.

RISK ANALYSIS

HAPG's Portfolio Optimization software performed stochastic analysis on a subset of the Cheyenne Light and Black Hills Power resource portfolios. Stochastic analysis provides a range of costs for each portfolio to serve load under a randomized set of assumptions for forecasted load, economy energy price, natural gas price, and coal price. The analysis examines the costs of each resource portfolio assuming 50 different "futures" and tabulates the PVRR expected for each of them. A risk profile for each resource portfolio is then constructed using all 50 of those "future" PVRR points.

For this IRP, HAPG combined the portfolio optimization production results with the financial results garnered from running the Strategic Planning module.

Figure 08-6 illustrates the risk profiles for Cheyenne Light resource portfolios. The deterministic PVRR results for Portfolios C1, C3, C5, C6, and C8 have similar risk profiles.

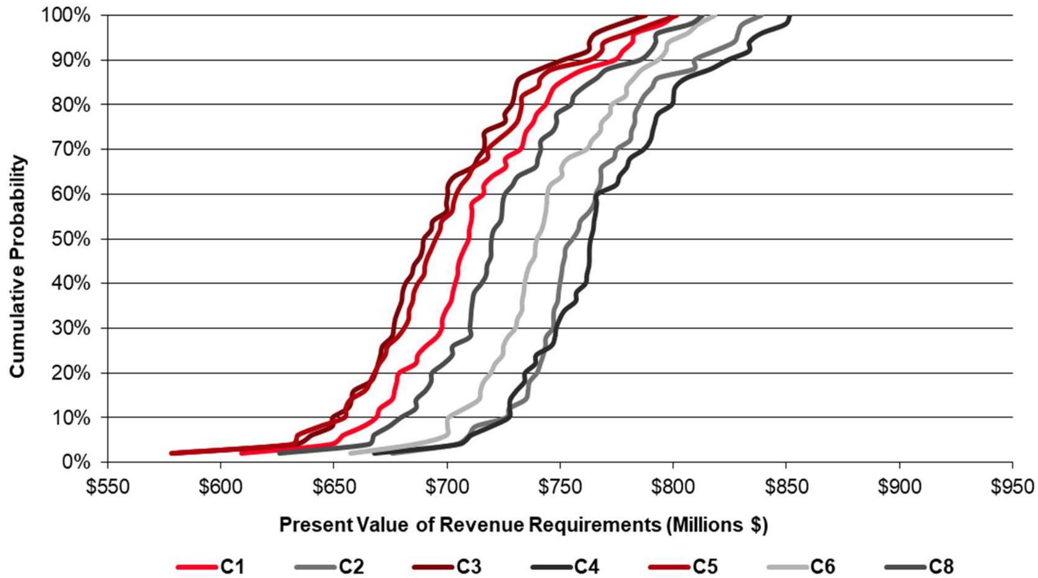


Figure 08-6. Risk Profile for Cheyenne Light Resource Portfolios

Figure 08-7 illustrates the risk profile for the Cheyenne Light base plan (Portfolio C1).

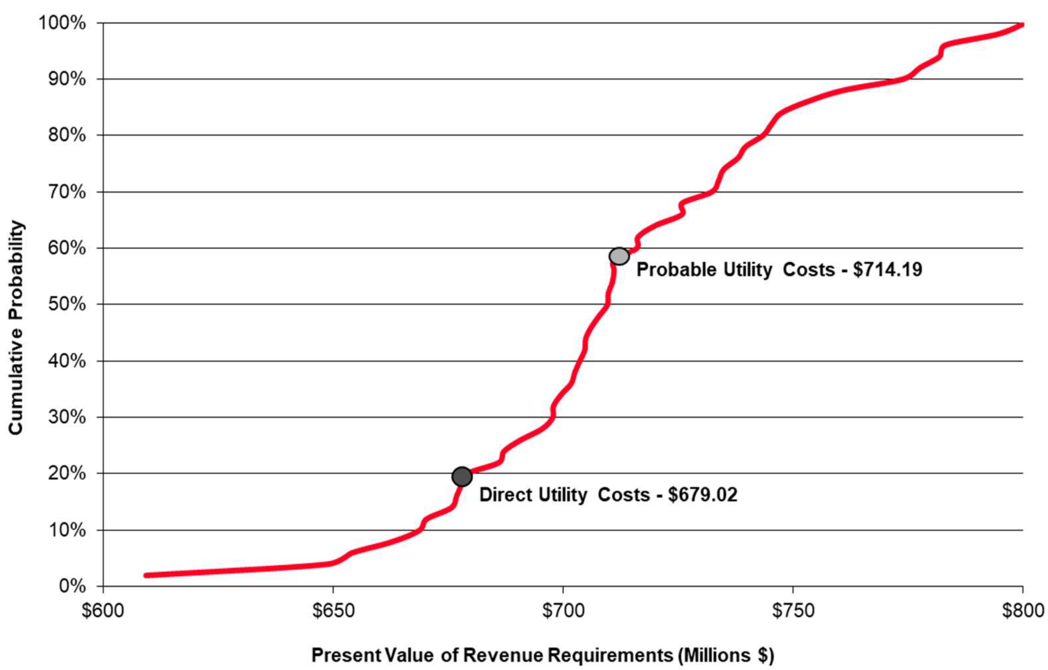


Figure 08-7. Cheyenne Light Risk Profile for the Base Plan

Figure 08-8 illustrates the future uncertainty of the Cheyenne Light resource portfolios. The difference between the expected value and the deterministic value is shaded in gray.

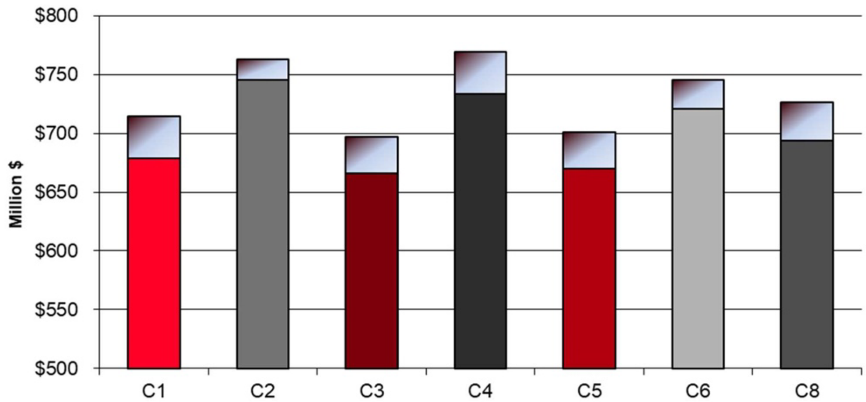


Figure 08-8. Cheyenne Light Combined PVRR and Risk Profile for Resource Portfolios

Figure 08-9 illustrates the risk profiles for Black Hills Power portfolios and scenarios. The deterministic PVRR results for Portfolios B1, B3, B5, and B6 have similar risk profiles.

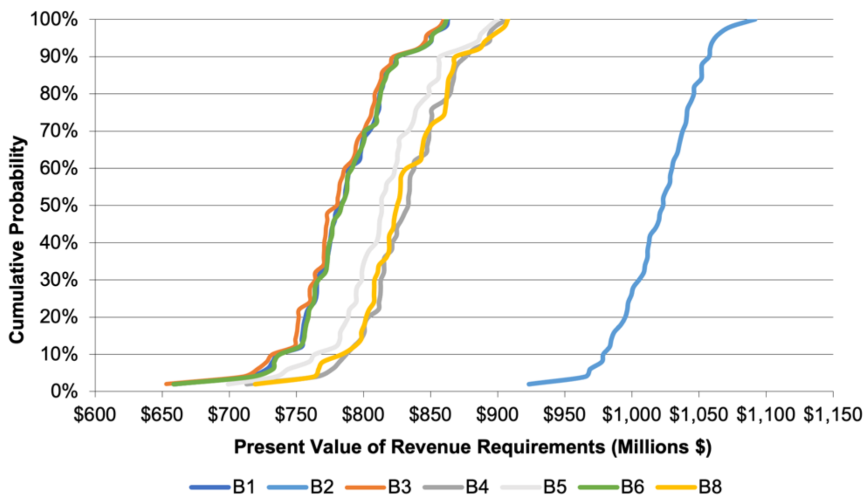


Figure 08-9. Risk Profile for Black Hills Power Portfolios and Scenarios

Figure 08-10 illustrates the risk profile for the Black Hills Power base plan (Portfolio B1).

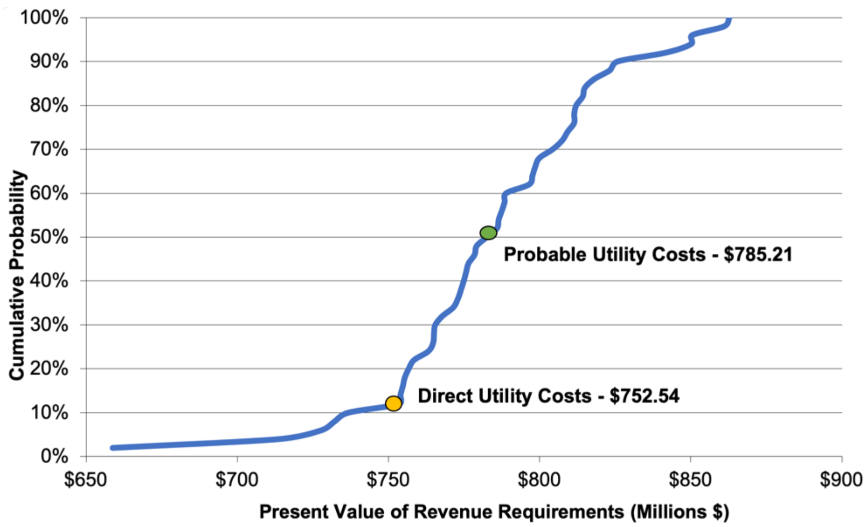


Figure 08-10. Black Hills Power Risk Profile for the Base Plan

Figure 08-11 illustrates the future uncertainty of the Black Hills Power resource portfolios. The difference between the expected value and the deterministic value is shaded in gray.

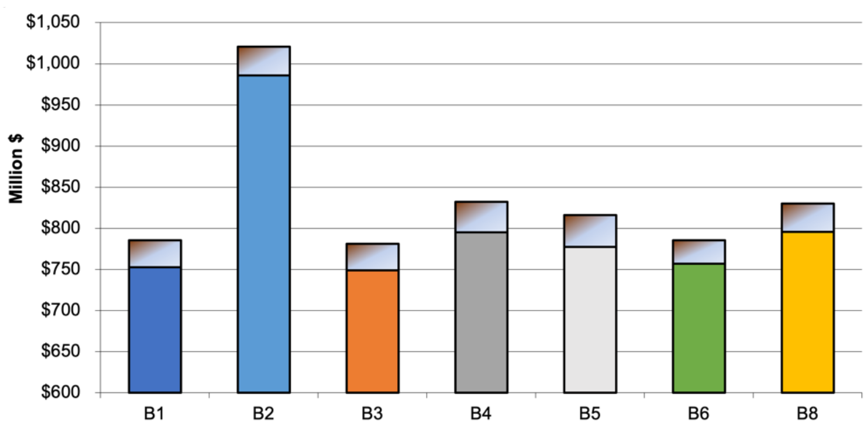


Figure 08-11. Combined PVRR and Risk Profile for Black Hills Power Portfolios and Scenarios

Resource Trade-Offs

HAPG developed trade-off diagrams to evaluate the level of risk tolerance of the Cheyenne Light and Black Hills Power resource portfolios. Trade-off diagrams provide a means to quickly compare many portfolios using two measures, such as least cost PVRR versus lowest risk (lowest volatility). In essence, a trade-off diagram summarizes the cost and risk measures of a risk profile.

Figure 08-12 illustrates the trade-off diagram for Cheyenne Light. It shows that Portfolio C1 has one of the lowest PVRR and the lowest standard deviation. Portfolio C3 has the lowest PVRR whereas Portfolio C6 has the lowest standard deviation.

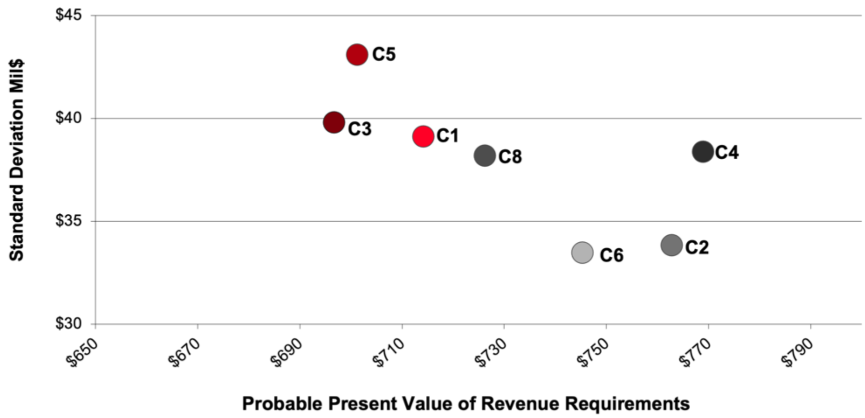


Figure 08-12. Trade-Off Diagram for Cheyenne Light Portfolios and Scenarios

Figure 08-13 illustrates the trade-off diagram for Black Hills Power like the Risk Profiles, there is little difference between Portfolios B1, B3, and B6 PVRRs and standard deviations.

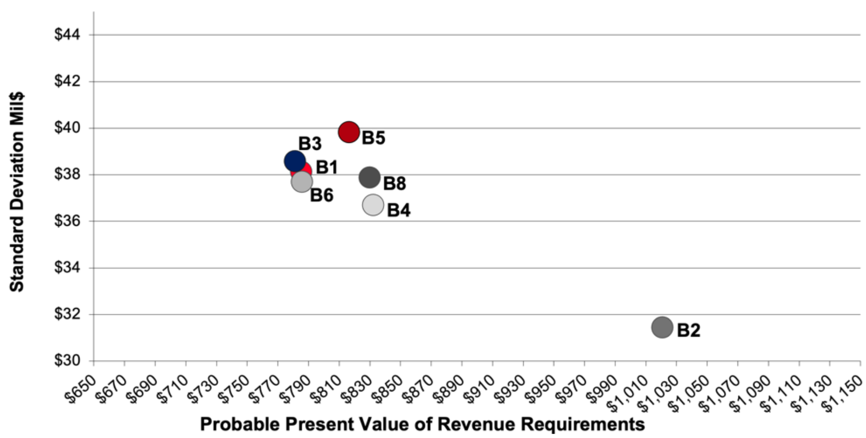


Figure 08-13. Trade-Off Diagram for Black Hills Power Portfolios and Scenarios

CLEAN Future Act

To better understand the potential implications to customers, Cheyenne Light and Black Hills Power conducted an analysis of the CLEAN Future Act for informational purposes.

Analysis of the CLEAN Future Act started with the resource portfolios developed in the environmental scenario (Portfolios B2 and C2). Generation dispatch within the production cost model was optimized to limit CO_2 emissions. Forecasted unit emissions produced by the production cost model were used to calculate alternative compliance payment (ACP) costs by year for each utility. Those ACP costs were combined with the forecasted annual operating costs from the production cost modeling to determine the cost of operating the system and complying with the proposed legislation. The analysis results indicate substantial risk of customer cost increases if the CLEAN Future Act were to be enacted in its current form. The graphs below compare the PVRRs of the base plans (Portfolios C1 and B1) to the CLEAN Future Act PVRRs for each utility.

Figure 08-14 compares the PVRR for Cheyenne Light's base plan (Portfolio C1) with that of the CLEAN Future Act.

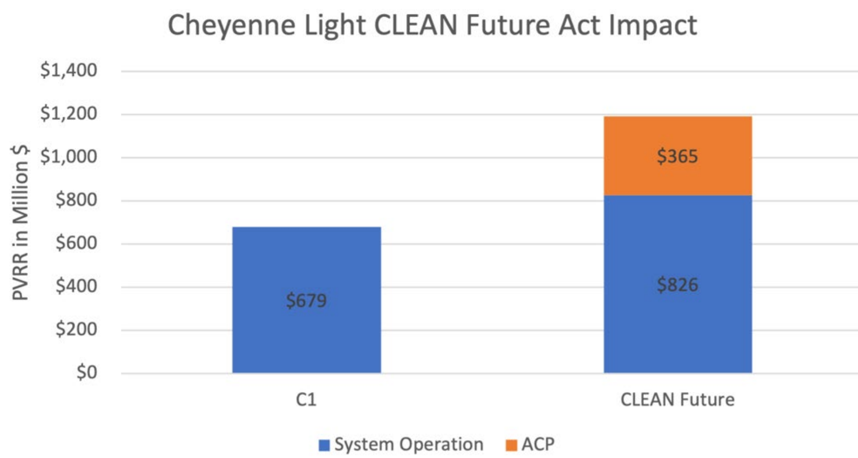


Figure 08-14. Cheyenne Light CLEAN Future Act PVRR versus Portfolio C1

Figure 08-15 compares the PVRR for Black Hills Power's base plan (Portfolio B1) with that of the CLEAN Future Act.

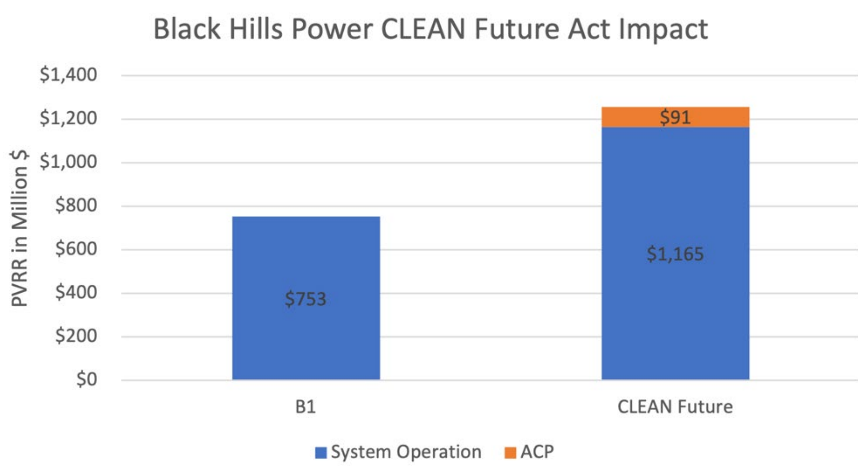


Figure 08-15. Black Hills Power CLEAN Future Act PVRR versus Portfolio B1

THE SELECTED PREFERRED PLANS

The Cheyenne Light and Black Hills Power preferred plans are developed to address resource needs during the near-term planning period. These plans are developed based on the results of the load and resource balance, capacity expansion, production cost modeling, and risk analysis. This information is considered individually and as a whole to make an informed recommendation that balances customer cost and risk.

Cheyenne Light Preferred Plan. Cheyenne Light's preferred plan (Portfolio C8) relies on up to 20 MW seasonal firm market purchases for capacity through the near-term need planning period. This is within the planning assumption of up to 50 MW of seasonal firm market purchases.

Black Hills Power Preferred Plan. The Black Hills Power preferred plan (Portfolio B8) calls for the addition of 100 MW of new resources during the near-term need period. Although the B8 portfolio designates the specific type of renewables, Black Hills Power will evaluate all types of renewable resources to meet the identified near-term planning period need in order to ensure the least cost, least risk resource is implemented. In addition, the preferred plan is to convert Neil Simpson Unit II from coal to natural gas in 2025.

Neil Simpson II is reaching the end of its design life in 2025. Black Hills Power engaged Black & Veatch to evaluate the condition of the plant and provide modeling inputs for life extension as a coal-fired resource, conversion to natural gas-fired, and retirement. These reports showed lower investment and operating costs for conversion to natural gas-fired as compared to life extension as a coal-fired resource. Based on this robust third-party analysis, Black Hills Power identified conversion to natural gas-fired as the most economical solution for customers in each capacity expansion scenario. Converting a coal unit to natural gas has many benefits. Natural gas conversions eliminate many expenses: coal costs, coal handling equipment, coal firing equipment, precipitators, ash handling equipment, ash disposal, and circulating dry scrubber and associated equipment. This existing equipment would be removed from service, lowering auxiliary power consumption.

Burning natural gas produces little to no ash. Thus, a natural gas conversion would eliminate water usage and wastewater discharge treatment costs associated with ash handling as well as virtually eliminate cleaning the air heater washes, boiler washes, precipitator washes, and dust control washes associated with ash deposition and fouling.

Finally, natural gas conversions reduce GHG emissions and act as a hedge against potential environmental emission-reduction regulations and legislation.

Battery Energy Storage Systems. Cheyenne Light's and Black Hills Power's preferred plans include the continued investigation of adding battery storage. Three factors drive inclusion of battery storage in the preferred plans. One, reduced battery storage capital costs, particularly those leveraging lithium-ion technology, have created an increased interest across the electric utility industry to deploy battery storage. Two, battery storage is an extremely flexible tool for managing the balance between electricity supply and demand. Battery storage can be used to smooth variable renewable energy resources and shift load from periods of high demand to periods of low demand. Three, battery storage provides customer benefits in structured power markets by providing ancillary services that would otherwise be provided by the market at a cost to customers.

Energy Market Participation. Cheyenne Light and Black Hills Power will continue to investigate customer benefits and costs of participating in organized energy markets and the transmission investment to fully unlock the customer benefits from those markets. When this evaluation is completed, Cheyenne Light intends to seek Commission approval as necessary.

Joint Preferred Plan. The joint modeling performed in the IRP assumes all existing and new Cheyenne Light and Black Hills Power resources are available to serve the combined system load. Because the timing of recommended resource additions for Cheyenne Light and Black Hills Power are not well-aligned, Cheyenne Light and Black Hills Power do not recommend a joint preferred plan, but instead recommend the individual preferred plans to meet the identified capacity shortfalls indicated in the IRP. The joint analysis is a productive addition to the IRP process, however, and the utilities recommend that this process be continued in the future as it may provide opportunities to the extent resource needs become better aligned.

Comparison to Previous IRPs

Cheyenne Light's most recent IRP, filed in 2018, did not recommend any resource additions in the current near-term need planning period of 2021 through 2026. The 2021 IRP preferred plan does recommend the continued investigation of the customer value proposition of adding battery storage.

Black Hills Power's most recent IRP, filed in 2011, called for the addition of a 100 MW coal plant in 2024. The 2021 IRP preferred plan calls for the addition of 100 MW of new renewable resources during the near-term need planning period, the conversion of Neil Simpson Unit II from coal to natural gas in 2025, and the continued investigation of the customer value proposition of adding battery storage.

These plan-to-plan differences are driven by updated modeling input forecasts, including load, energy prices, and resource characteristics. The inclusion of battery storage is a result of reduced capital costs and increased system benefits. The change in Black Hills Power's resources is a result of Neil Simpson II reaching the end of its design life in 2025.

Conclusion

The IRP identifies that the forecasted future needs of Cheyenne Light and Black Hills Power will be best met through a balanced mix of generation resources, including coal, natural gas, solar, and wind. In addition, the preferred plan for each utility includes the continued investigation of adding battery storage to further diversify their resource portfolios. Unlike prior IRPs submitted by the utilities, this IRP includes an analysis of the resource needs of Cheyenne Light individually, Black Hills Power individually, and a joint analysis of a combined load for the two utilities.

For Cheyenne Light, the IRP identified a near-term baseload capacity shortfall of 10 MW beginning in 2021, driven by native load growth on the system. The IRP also identifies the benefits of exploring an investment in an expansion of Cheyenne Light owned transmission to lower costs associated with the Western Area Power Administration Loveland Area Project (WAPA-LAP) transmission system. Based on forecasts and analysis, Cheyenne Light recommends seasonal firm market purchases in the near-term need planning period as the preferred, least cost alternative to meet the identified capacity shortfall. In addition, Cheyenne Light recommends the evaluation of a utility owned transmission expansion within the near-term need planning period as the least cost alternative to current WAPA-LAP transmission expenses. Finally, the Cheyenne Light preferred plan includes the continued investigation of the customer value proposition of adding battery storage.

For Black Hills Power, the IRP identified a near-term baseload capacity shortfall of 40 MW beginning in 2023, driven by native load growth on the system and the end of design life of the Neil Simpson Unit II coal-fired steam power plant in 2025. Based on forecasts and analysis, Black Hills Power recommends the addition of up to 100 MW of renewable resources in the near-term need planning period and the conversion of Neil Simpson Unit II as the preferred, least cost alternative to meet the identified capacity shortfall. Finally, the Black Hills Power preferred plan includes the continued investigation of the customer value proposition of adding battery storage.

Because the timing of recommended resource additions for Cheyenne Light and Black Hills Power are not well-aligned, Cheyenne Light and Black Hills Power do not recommend a joint preferred plan, but instead recommending the individual preferred plans to meet the identified capacity shortfalls in the IRP. The joint analysis is a productive addition to the IRP process, however, and the utilities recommend that this process be continued in the future as it may provide opportunities to the extent resource needs become better aligned.