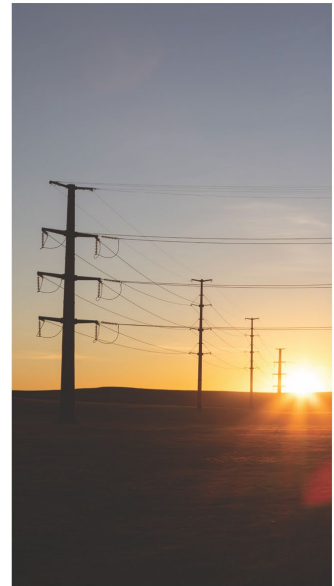
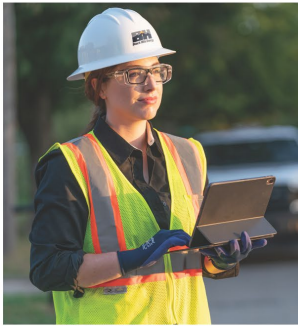




Cheyenne Light, Fuel and Power Company, Inc.

2026 Integrated Resource Plan



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Executive Summary

The Integrated Resource Plan (“IRP”) process and evaluation for Cheyenne Light, Fuel, and Power, Inc. d/b/a Black Hills Energy (“Cheyenne Light” or the “Company”) supports forecasted future needs of the utility which will be best met through a balanced mix of generation resources including coal, natural gas, wind, and energy storage. This IRP includes an analysis of the resource needs of Cheyenne Light.

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 and regulatory requirements.

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

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

This IRP identified a near-term capacity shortfall for Cheyenne Light of 95 MW beginning in 2027. Based on forecasts and analysis, Cheyenne Light recommends the addition of natural gas fired reciprocating internal combustion engines (“RICE”) with a nameplate capacity of 36 MW and 50 MW of energy storage in the near-term need planning period as the preferred, least-cost and least-risk alternative to meet the identified resource need. The gas resources will economically provide firm capacity and will be available to quickly adapt to any changes in load and resource needs. Similarly, energy storage will economically address the capacity shortfall while providing fast low-cost energy compared to other alternatives.

Due to the timing and resource need for Cheyenne Light, Cheyenne Light recommends this preferred plan to meet the near-term capacity shortfall identified in the IRP. As a point of reference, this IRP does not address any Large Power Contract Service (“LPCS”) capacity needs which are handled separately under customer specific contracts per the LPCS Rate Schedule. Pursuant to the LPCS Tariff provisions, LPCS customers must have their own Eligible Capacity Resources (as defined in the LPCS Tariff) that are greater than or equal to 115% of the customer’s actual peak monthly load served. In addition, there are ring fencing provisions contained in the LPCS Tariff which provide that LPCS customers will have costs assigned to them individually based upon cost causation principles based on the characteristics of the electric service that has been contracted for by the customer, including the costs of any Eligible Capacity Resources.

Cheyenne Light is in the beginning stages of developing the required applications to the Wyoming Public Service Commission for approval to construct 36 MW of RICE and 50 MW of energy storage identified in the preferred plan and anticipates making these filings in the second half of 2026 or 2027. The RICE units and energy storage will likely be located in Cheyenne, Wyoming. Cheyenne Light is targeting an in-service date of 2029 for the RICE and energy storage units, while continuing to explore potential resource partnerships, so that it can continue to provide safe and reliable energy to its customers in Wyoming.

1. INTRODUCTION

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. This IRP addresses the future needs of Cheyenne Light.

1.1 Background – Cheyenne Light

Cheyenne Light provides electric service to approximately 46,000 residential, commercial, industrial, and municipal customers in Laramie County, Wyoming. In 2025, Cheyenne Light sold approximately 2,767 GWh to its retail customers. In May 2026, the Company achieved a system peak of 409 MW, the highest load level recorded by the Company to date. The Company's generating stations are located in Gillette, Wyoming and Cheyenne, Wyoming.

The Company currently meets customer electric demand and energy needs using a mix of Company-owned generation resources, Power Purchase Agreements ("PPA"), and via purchases from the market as needed. The Company's generation portfolio includes:

- Two coal-fired generating units with a nameplate capacity of 150 MW:
 - 90 MW Wygen II utility owned coal-fired generation
 - 60 MW Wygen I power purchase agreement which expires at the end of 2032
- Two natural gas-fired generating units with a nameplate capacity of 77 MW:
 - 40 MW LMCC1 CPGS utility owned natural gas fired generation
 - 37 MW LM6000 CPGS utility owned natural gas fired generation
- Three wind stations with a nameplate capacity of 43.65 MW
 - 20 MW of utility owned wind resources
 - 23.65 MW wind through two PPAs which expire by the end of 2029

The Cheyenne Light power delivery system consists of approximately 366 miles of transmission and sub-transmission lines and 1,373 miles of distribution lines.

1.2 Overview of the 2021 IRP

Cheyenne Light's last IRP was completed and filed in June of 2021. Cheyenne Light's 2021 preferred plan did not include resource additions but rather relied on market purchases to meet capacity needs. The 2021 preferred plan also recommended further investigation into Battery Energy Storage Systems ("BESS") storage and evaluation of increasing utility owned transmission. While the 2021 IRP storage resource is no longer being pursued, this 2026 IRP has identified a 50 MW energy storage and 36 MW RICE need.

1.3 Cheyenne Light Customer Mix

Cheyenne Light provides retail electric service to customers located in Laramie County, Wyoming.

Table 01-1 shows average customer counts for Cheyenne Light for the years 2021-2025. Year over year growth rates are approximately 1.25 percent.

Table 01-1
Cheyenne Light's Customer Count Trend

Class	2021	2022	2023	2024	2025
Residential	38,582	39,137	39,445	39,953	40,400
Commercial	4,986	5,073	5,137	5,237	5,371
Industrial	3	3	3	3	3
Municipal	209	201	203	194	204
Total	43,780	44,414	44,788	45,387	45,978

Figure 01-1 illustrates the total number of commercial, industrial, residential, and municipal customers served in Cheyenne Light's service territory.

Figure 01-1
Cheyenne Light Customer Count

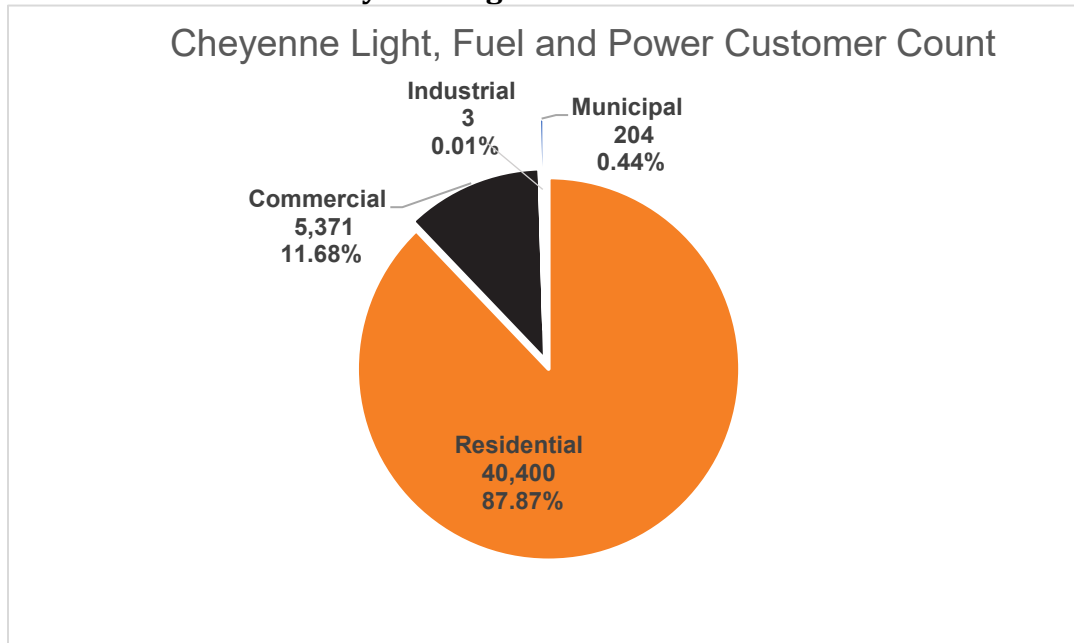
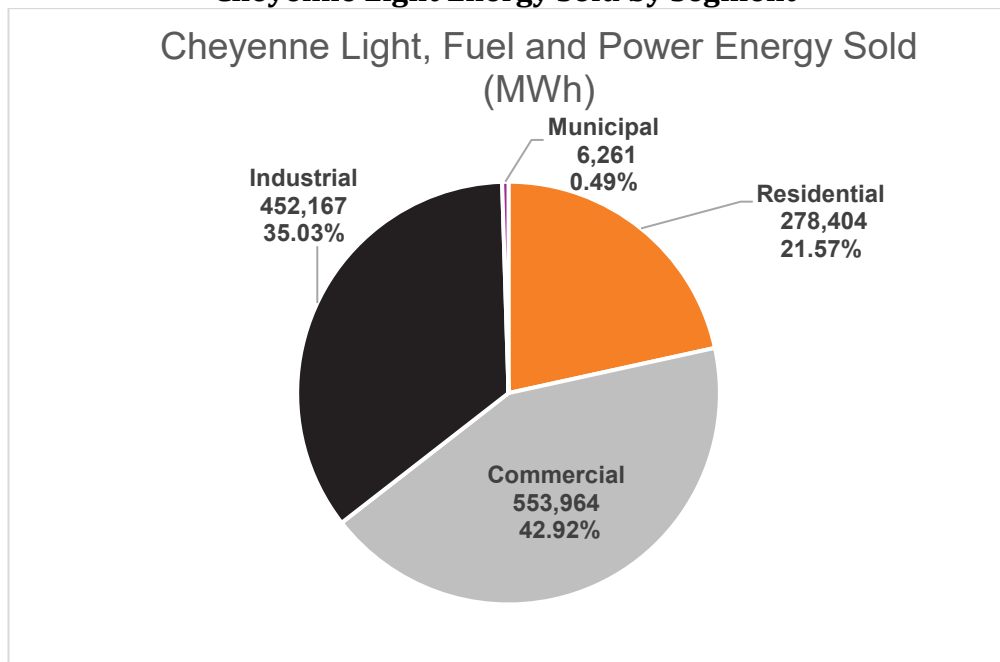


Figure 01-2 illustrates the amount of energy sold by Cheyenne Light to each customer segment t.

Figure 01-2
Cheyenne Light Energy Sold by Segment



1.4 Cheyenne Light Service Territory

Cheyenne Light provides energy to residential, commercial, industrial, and municipal customers in Laramie County, Wyoming. The utility maintains 366 miles of transmission lines and 1,385 miles of distribution lines.

Five of Cheyenne Light's generating stations are located within the Company's service territory including three wind generating stations and the two natural gas generating stations located at the Cheyenne Prairie Generating Station ("CPGS") (LMCC1 combined cycle and a LM6000 simple cycle). Two additional coal fired Cheyenne Light generating stations are located in the Gillette Energy Complex near Gillette, Wyoming (Wygen I and Wygen II).

1.5 Conclusion

For 143 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 2026 IRP is a key component of the company's ongoing commitment to cost-effectively plan and execute on plans to meet the needs of customers.

2. PLANNING ENVIRONMENT

The environment in which Cheyenne Light must plan for future resources continues to evolve with circumstances beyond the control of the utility. Cheyenne Light closely monitors pending environmental regulations and requirements and incorporates those requirements as appropriate into the IRP process. From this, the utility makes action plans and determines the costs to comply. Recent regulatory actions are summarized in the following paragraphs.

2.1 EPA Greenhouse Gas Emissions Standards for New and Existing Electric Generating Units

On April 25, 2024 the U.S. Environmental Protection Agency ("EPA") finalized regulations under Clean Air Act ("CAA") section 111 creating emissions standards for greenhouse gas ("GHG") from new and existing fossil-based thermal generation. The CAA requires U.S. EPA to conduct an analysis of potential control systems to determine the best system of emissions reduction ("BSER") considering construction and operating costs, energy requirements, non-air quality health and environmental impacts, and whether the control system is adequately demonstrated. BSER for coal-fired plants and new natural gas-fired combustion turbines ("CT") is the application

of carbon capture technologies to achieve a 90 percent reduction in GHG emissions. BSER for natural gas-fired plants, excluding combustion turbines, is to achieve GHG emissions limits using efficient combustion practices. U.S. EPA recognized that BSER was not feasible for all plants and issued alternative compliance strategies, including fuel blending with 40 percent natural gas, which are summarized in the Table 02-1 below.

Table 02-1
Final BSER and Resulting Performance Standards

	Through Dec. 31, 2031	Jan. 1, 2032 – Dec. 31, 2038	2039 and beyond
111(d) – Existing Steam EGUs (coal-fired)			
• Retire by 12/31/2031	Excluded from regulation	Unit retired	
• Retire 2032-2038	40% natural gas co-firing, presumed 16 percent emissions reduction; beginning 1/1/2030**		Unit retired
• Retire after 1/1/2039	No applicable standard	CCS at 90% capture rate, presumed 88.4 percent emissions reduction **	
111(d) – Existing Steam EGUs (gas-fired)			
• ≥45% Capacity Factor	Routine efficient operations; 1,400 lb CO2/MWh beginning 1/1/2030		
• <45% Capacity Factor	Routine efficient operations; 1,600 lb CO2/MWh beginning 1/1/2030		
• <8% Capacity Factor	Uniform Fuels; 170 lb CO2/MMBtu for oil-fired sources and a presumptive standard of 130 lb CO2/MMBtu for natural gas-fired sources		
111(d) - Existing Combustion Turbines: EPA deferred action. Proposed rule in December or January			
111(b) – New High Utilization Combustion Turbines			
• Base load > 40%	Highly efficient generation/best O&M practices 800 lb CO2/MWh for > 2,000 MMBTU/h Units 900 lb CO2/MWh for < 2,000 MMBTU/h Units	CCS at 90% capture rate 100 lb CO2/MWh for > 2,000 MMBTU/h Units 110 lb CO2/MWh for > 2,000 MMBTU/h Units	
111(b) – New Intermediate and Low Utilization Combustion Turbines			
• Intermediate CT > 20% CF to ≤ 40% CF	Efficient operations 1,170 lb CO2/MWh		
• Low Utilization (CT)** ≤ 20% CF	Use of clean fuels (NG, Nos. 1 & 2 fuel oil); 20% annual CF restriction 120-160 lb CO2/MMBTU		

On June 11, 2025, EPA proposed a rule to repeal all greenhouse gas (GHG) standards for fossil fuel-fired power plants. The proposal was published in the Federal Register

on June 17, 2025, with public comments accepted through August 7, 2025. EPA is expected to issue the final rule by August 1, 2026. Separately, EPA issued a final rule rescinding the 2009 Greenhouse Gas Endangerment Finding for light-duty, medium-duty, and heavy-duty vehicles and engines.

2.1.1 Carbon Capture, Utilization, and Storage

Reference to the 111(d) 90 percent Carbon Capture, Utilization, and Storage (“CCS,” also referred to as carbon capture, utilization, and sequestration) technologies are currently being researched and tested to remove Carbon Dioxide (“CO₂”) from air emissions. Carbon capture separates and entraps CO₂ from large stationary sources, including power plants, industrial boilers, refineries, and natural gas wells. Carbon sequestration captures and securely stores CO₂ that would otherwise be emitted and remain in the atmosphere.

Federal guidelines currently are focused on carbon captured primarily where CO₂ must be stored through Class VI well permits so that it cannot be emitted back into the atmosphere or utilized in industry such as enhanced oil recovery (“EOR”). Considerations and requirements for storage are: (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 for storage include deep saline formations (subterranean and sub-seabed) and depleted oil and gas reservoirs. Geologic formations for utilization include EOR, and non-mineable coal seams.

Notably, the State of Wyoming has constructed the Integrated Test Center (“WY ITC”) at the Dry Fork Station near Gillette, Wyoming. Starting in the fall of 2019, various companies began using the Integrated Test Center to test several technologies for separating and sequestering CO₂. Larger scale projects are currently underway, namely Membrane Technology and Research, Inc. (“MTR”) which utilizes membrane technology to absorb CO₂ to concentrate from the flue gas. The technology was operational in Q1 2025 and successfully demonstrated the technical ability for a membrane to concentrate a portion of a coal fired powerplants flue gas to near purity CO₂ levels

The National Carbon Capture Center (“NCCC”) in Wilsonville, AL has been in operation since 2009 and evaluated 75+ technologies over 145,000 hours of operation and continues to evaluate and provide a test center with “real” flue gas (both natural gas and coal) for testing/processing in order to promote Technical Readiness Level (“TRL”) evaluation and propagation. To date the Amine technologies are the only TRL 9 (Commercial ready) but have significant costs and parasitic loads associated.

Black Hills Energy has engaged with both testing facilities (WY ITC and NCCC) and numerous technology companies associated with the current prospects of capturing CO₂. Through a grant from the Wyoming Energy Authority (“WEA”), Black Hills Energy studied the feasibility of generating hydrogen from our Wyodak mined coal utilizing an innovative BrightLoop™ chemical looping technology. Along with our partners, Babcock & Wilcox and Ohio State University, feasibility and laboratory testing was completed on the coal. This research supported moving forward to a demonstration phase. A second WEA grant, totaling \$16 million, funded Front-End Engineering Design (“FID”) for a pilot-scale BrightLoop™ hydrogen plant at the Neil Simpson Complex in Gillette, Wyoming. Pending results of the FID, the pilot-scale project could be operational by 2030.

Black Hills Energy is also partnering with membrane technology companies, Membrane Technology and Research (“MTR”) is included in this partnership and Carbon GeoCapture to test MTR’s membrane system for capturing and concentrating greenhouse gas emissions from the coal units at our Neil Simpson Complex. The pilot project would concentrate CO₂ for coal bed methane recovery through Class II underground wells. The utilization of Class II wells reduces the purity requirements of the CO₂ which makes the system less complex and more cost-effective. Under a previous BrightLoop™ WEA grant, three Class II wells were permitted and drilled, and testing confirmed that the coal formations are well-suited for this type of project.

This pilot will be co-funded through a grant recently awarded by the WEA and through Cheyenne Light’s Low Carbon Surcharge. Phase I will complete well development and install equipment to move water within the coal seam to prepare for CO₂ injection. Once complete, pure CO₂ will be injected into the wells and mixed with the circulating water to measure how quickly it can be injected and how well the coal seam absorbs it, all without impacting other aquifers. Phase II will add the membrane equipment and connect it to a slip-stream of the coal plant flue gas. This will supply partially concentrated CO₂ to the wells and system built in phase I. The full proof-of-concept pilot is expected to be completed by the end of 2027.

2.2 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. The rule was amended in 2024 to reflect similar requirements as outlined in the IRA 45Q tax language primarily related to carbon dioxide capture rate at 75% of baseline of carbon dioxide produced from design requirements and capture at least 18,750 Metric Tons per annum. The rule was also amended to exclude regulated power units owned by utilities with less than 10,000 customers located in the state of Wyoming.

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 CCS technology, apply to allow revenues from the sale of captured CO₂ to be returned to the utility's shareholders and seek up to a two percent surcharge from utility customers.

2.3 Regional Haze

EPA's regional haze rule, finalized in 1999, requires states to develop and implement plans to improve visibility in 156 national park and wilderness areas. The majority of these areas are in the western United States. States are required to periodically update their regional haze rule plans. The second planning period runs from 2021 to 2028. Subsequent planning periods are on a 10-year cycle. Progress reports are due every five years and are intended to provide a progress report on, and, if necessary, mid-course corrections to, each regional haze state implementation plan ("SIP"). The progress report provides an opportunity for public input on the state's assessment of whether the current regional haze SIP is appropriate and is achieving visibility progress projected in the SIP.

Wyoming filed their SIP for the second planning period on August 10, 2022, which included a commitment to review visibility impairing emissions of Nitrogen Oxide ("NO_x"), Sulfur Dioxide ("SO₂"), and PM from electric generating units at the Neil Simpson Complex, including Wygen I. A regional haze four-factor emissions control analysis was provided to Wyoming on June 17, 2024. The four-factor analysis demonstrated additional NO_x controls on the existing coal-fired plants are not economically feasible as the units are either equipped with state-of-the-art selective catalytic reduction systems or the emission reductions achieved from installing selective catalytic reduction are cost-prohibitive. Wyoming's SIP for the second planning period did not require additional NO_x, SO₂, or PM emissions controls for large, industrial facilities as the state is achieving the required visibility improvement under the current emissions control strategy.

On August 1, 2024, EPA Region 8 issued a proposal to approve portions of Wyoming's second planning period regional haze SIP and disapprove others, including Wyoming's long-term strategy to reduce NO_x, SO₂, and PM emissions. Subsequently, on February 19, 2026, EPA issued updated guidance for second planning period SIPs, which directs states to consider impacts to grid reliability when determining whether additional control measures are needed to demonstrate reasonable progress in reducing regional haze. This guidance revision is anticipated

to further support Wyoming's decision that no additional emissions controls are needed during the second planning period as monitored visibility improvement continues to show better improvement than the EPA's Uniform Rate of Reasonable Progress sets. A final decision on Wyoming's second planning period SIP is anticipated in 2026.

Recently, EPA finalized a one-time deadline extension for Regional Haze third implementation period, moving the SIP due date from July 31, 2028, to July 31, 2031. This action was signed on December 31, 2025, and became effective on March 9, 2026. The third planning period still covers 2028 to 2038 even though SIPs are not due until the middle of 2031.

2.4 Other Environmental Considerations

The EPA continues to modify and add additional rules that affect existing and future fossil fuel based electric generation resources. These rules may require existing capital to be expended on existing resources and affect the operation and maintenance expenses of those facilities.

2.4.1 Revised PM_{2.5} National Ambient Air Quality Standard

On February 2024, EPA revised the PM_{2.5} National Ambient Air Quality Standard ("NAAQS") to lower the federal primary PM_{2.5} annual standard from 12.0 µg/m³ to 9.0 µg/m³. The new annual standard became effective May 6, 2024, and all air quality permitting decisions issued after that date must demonstrate compliance with the 9.0 µg/m³ standard. The secondary annual PM_{2.5} standard remains 15.0 µg/m³. Initial air quality classification recommendations, including proposed nonattainment areas, were due to EPA by February 2025, after which EPA had 12 months to issue final designations. EPA did not meet the Clean Air Act deadline to issue final nonattainment designations by February 7, 2026. The Agency has indicated it may delay the designation process by up to one year to allow states additional time for air monitoring and modeling work needed under the revised standard. There is additional uncertainty as to whether the new standard will remain in place as EPA has requested the D.C. Circuit Court vacate the 2024 PM_{2.5} standard in their December 23, 2025 filing in the case *Commonwealth of Kentucky v. EPA*, Case No. 24-1050.

2.4.2 Mercury and Air Toxics Standards

On April 25, 2024, the EPA finalized the *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review* rule, commonly referred as Mercury and Air Toxics Standards ("MATS") Risk and Technology Review. The MATS RTR finalized a lower filterable particulate matter ("fPM") emissions standard of 0.010 lb/MMBtu. EPA also finalized a new requirement to use a fPM continuous emission monitoring system to demonstrate compliance with the revised fPM standards. Subsequently, on

February 24, 2026, EPA published in the Federal Register a final rule formally repealing the 2024 amendments to MATS and returning all affected units to the 2012 MATS standards. The final rule became effective April 27, 2026, and imposes no additional compliance costs on Cheyenne Light. Final impacts will be known after current litigation to bring back the 2024 MATS revisions is resolved.

2.4.3 Ozone Transport Rule

EPA proposed its “Good Neighbor Rule” for the 2015 ozone NAAQS (the Ozone Transport Rule or “OTR”) on April 6, 2022, as an update to the existing Cross-State Air Pollution Rule (“CSAPR”) framework. Although the proposal initially included Wyoming among the 26 states evaluated, this inclusion was based on preliminary modeling that suggested certain states might contribute to downwind ozone exceedances. Under the proposed framework, any state found to significantly contribute to another state’s nonattainment would be subject to emission reductions through CSAPR. EPA also issued a separate action on May 24, 2022, proposing to disapprove several ozone transport SIPs, including Wyoming’s, which would have placed Wyoming under a CSAPR federal implementation plan.

However, updated technical analyses changed the outcome. On March 15, 2023, EPA issued its final Good Neighbor Rule, and Wyoming was explicitly excluded from the final list of 23 regulated states. Revised air dispersion modeling and updated emissions inventories demonstrated that Wyoming sources do not contribute to ozone exceedances in Colorado or any other downwind state. As a result, the rule does not apply to Wyoming, and the state is not subject to any CSAPR obligations under this action. EPA subsequently reaffirmed this conclusion on December 19, 2023, when it approved Wyoming’s ozone SIP, confirming that Wyoming met its “good neighbor” obligations and therefore Wyoming sources, including Cheyenne Light’s thermal power generating units, remain outside the scope of the CSAPR program. The SIP approval became effective January 18, 2024.

2.4.4 Coal Combustion Residuals Rule

EPA finalized national minimum criteria for existing and new coal combustion residuals (“CCR”) landfills and existing and new CCR surface impoundments on April 17, 2015. These requirements apply to active facilities and remain the primary regulatory framework governing CCR management.

On August 21, 2018, the U.S. Court of Appeals vacated the exemption for inactive surface impoundments at inactive facilities and remanded the issue to EPA, prompting the Agency to develop new requirements for these “legacy” units. In response, EPA issued a rule on May 8, 2024, establishing regulatory obligations for legacy CCR surface impoundments and for certain CCR management units located at inactive facilities. These revisions finalized requirements for inactive surface impoundments at inactive electric utilities, referred to as legacy CCR surface impoundments, including the completion of a facility evaluation report to determine

appropriate closure actions and to implement ongoing water monitoring. The final rule was effective November 4, 2024. EPA later issued another final rule, effective February 9, 2026, extending several compliance deadlines for legacy CCR landfills and surface impoundments by 12 or more months.

Cheyenne Light's existing coal-fired generation is located at an active facility which does not operate a CCR landfill or surface impoundment subject to the final rule. CCR from the coal-fired unit is subject to reclamation requirements imposed by the Wyoming Department of Environmental Quality.

2.4.5 Effluent Guideline Rule

On April 25, 2024, EPA finalized the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category (2024 ELG Rule or Final Rule), which applies to wastewater discharges from coal-based generating units. The rule builds upon the 2015 and 2020 ELG Rules and establishes pollution control requirements on four waste streams: (1) bottom ash transport water, (2) flue gas desulfurization wastewater, (3) coal combustion residual leachate, and (4) legacy wastewaters. The deadline for compliance for these waste streams is December 31, 2029. EPA published a final rule on December 31, 2025, extending the compliance deadlines for regulated wastewater streams to December 31, 2034. The rule was effective March 2, 2026.

2.5 Risk Analysis of Pending Federal Policies

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

Some Federal policies present opportunities:

- Infrastructure modernization and improvement incentives (financial and regulatory consideration) for transmission and delivery systems.
- Advanced energy research and development incentives, including funding for emissions free technologies such as carbon capture, hydrogen, battery storage, renewables, and energy efficiency.

Other Federal policies also 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.

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

2.5.1 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.

2.5.2 Utilities Presumption Against Requirements

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.

2.5.3 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.

2.6 Data Centers

Data centers have been on the rise across the United States. According to the Department of Energy, these data centers can consume anywhere from 10 to 50 times more energy per floor space than a typical office building. Recent federal analysis indicates that data center electricity demand has accelerated materially in recent years, driven largely by expansion in cloud computing services and energy-intensive artificial intelligence applications. Data centers consumed approximately 176 terawatt-hours of electricity in 2023, representing about 4.4 percent of total U.S. electricity use. Electricity demand from data centers could increase to between 325 and 580 TWh by 2028, potentially accounting for up to 12 percent of national electricity demand. This projected growth highlights the importance of incorporating data center load growth into long-term energy and capacity planning.¹ These facilities typically operate continuously, with high load factors and limited load flexibility, which differentiates their demand profile from traditional commercial customers and heightens their potential impact on system planning needs.²

The state of Wyoming has been proactive in trying to attract data centers with Cheyenne becoming a hot spot for data center activity. Currently data centers in the state of Wyoming receive a sales tax exemption on equipment and power purchases over \$2 million if investments in capital construction or rent exceed \$50 million.³

Currently, there are eight data centers in the Cheyenne Light area that take electric service from Cheyenne Light under various rate schedules based on their size and service requirements and that employ over 250 full time employees, with an estimated additional 150 jobs to support ongoing data center operations (not including construction). These data centers contribute \$100 million annually to the Wyoming gross domestic product and since opening, have spent \$6.9 billion in capital investments, paid \$111.6 million in total employee direct and indirect wages, paid \$27 million in sales taxes, and paid \$55.3 million in property taxes. There are

¹ Source: <https://www.energy.gov/articles/doe-releases-new-report-evaluating-increase-electricity-demand-data-centers>

² Source: <https://www.congress.gov/crs-product/R48646>

³ Source: <https://wyoleg.gov/InterimCommittee/2022/03-2022112104-042022DataCenterExemptionReport.pdf>

five new data centers under construction in the Cheyenne area which will add to these economic benefits for Wyoming.⁴

To address the needs of data center customers, Cheyenne Light has implemented tariff provisions that apply to these customers, or those that are large power users. Specifically, the LPCS rate schedule is for large power users who have expected load requirements of 18,000 kW or greater (including at least 13,000 kW of load required to be on either the Industrial Transmission Service or Industrial Contract Service rate schedules). The Industrial Transmission Service (“ITS”) rate schedule is applicable to large industrial power users taking service at transmission level voltage or who have contractual arrangement to pay for any distribution facilities required to serve them whose total minimum capacity requirements are 13,000 kW or greater.

The LPCS rate schedule is an innovative tariff implemented pursuant to Wyoming Statute 37-3-116 that allows electric utilities to enter into service agreements with customers provided those agreements do not result in obligating other customers for any utility investments or any direct, indirect or reasonably assigned costs related to providing service to the customer. The statutory provisions are imbedded in the LPCS rate schedule which requires LPCS customers to have their own Eligible Capacity Resources (as defined in the LPCS Tariff) that are greater than or equal to 115% of the customer’s actual peak monthly load served. In addition, there are ring fencing provisions contained in the LPCS Tariff which provide that LPCS customers will have costs assigned to them individually based upon cost causation principles based on the characteristics of the electric service that has been contracted for by the customer, including the costs of any Eligible Capacity Resources. In addition, customers taking service under the LPCS rate schedule will not be combined with other retail customers for purposes of class cost of service studies or cost allocations. All of these provisions in the LPCS rate schedule are designed to protect other base retail customers from any costs associated with providing service to these large LPCS customers.

2.7 Economic Conditions Affecting Cheyenne Light

Economic conditions are important factors that impact the supply and demand of electricity. As economic activity expands, electric demand typically increases across residential, commercial, and industrial sectors, placing upward pressure on pricing. Current labor and housing market indicators point to continued economic strength at the national, state, and local levels, supporting expectations of sustained electric load growth.

At the national level, the U.S. Bureau of Labor Statistics reported an unemployment rate of 4.3 percent in January 2026.⁵ Unemployment rates varied across the country

⁴ Source: [Data-Center-Facts-5.4.2026-2.pdf](#) and [Final Data Center Educational Power Point Betsey 2.6.2026.pdf](#)

⁵ Source: <https://www.bls.gov/cps/>

ranging from a high of 5.4 percent in California and a low of 2.2 percent in South Dakota.⁶ These differences highlight regional economic variability that may affect localized electricity demand trends.

Housing market activity can also provide insight into economic indicators. In March 2026, the national median price for existing home sales rose by an annual rate of 1.4 percent, reaching \$403,100. The median price for existing single-family home sales rose by 1.3 percent to \$412,400. Homes sold in 41 days on average. While home sales are 1.0 percent lower than one year ago, available housing inventory was at 1.36 million properties, up by 2.3 percent.⁷

State and local economic indicators demonstrate conditions that are generally more favorable than national averages. As of February 2026, Wyoming's unemployment rate was 3.6 percent which was below the national average. Cheyenne's unemployment rate was reported slightly higher than the statewide average at 3.7 percent but still below national levels. The average annual wage in the Cheyenne area is \$63,908, supporting household income stability and consumer spending.⁸

Within the Cheyenne Light service territory, economic activity has remained comparatively strong. In Laramie County, both total taxable sales and total retail sales increased in 2025. Total taxable sales rose 6 percent from 2024 to 2025, while total retail sales increased 10.25 percent during the same period. Correspondingly, sales and use tax receipts increased 6.2 percent year over year, reaching the highest nominal levels recorded in the county.

When adjusted for inflation, tax receipts remain slightly below the 2023 peak, indicating some moderation but continued economic strength. The county's average unemployment rate in 2025 was 3.4 percent, a modest increase from 3.1 percent in 2023, which represented the lowest annual unemployment rate recorded in Laramie County since 1985.⁹

Overall, these economic indicators suggest stable and relatively strong conditions within the Cheyenne Light service territory. Low unemployment, sustained wage levels, continued housing market activity, and increasing taxable sales support assumptions of steady customer growth and electricity demand.

2.8 Fuel Markets and Trends

This section addresses how Cheyenne Light's purchase, transport, and use of coal and natural gas impact operations.

⁶ Source: <https://www.bls.gov/lau/>

⁷ Source: <https://www.nar.realtor/infographics/existing-home-sales-housing-snapshot>

⁸ Source: https://www.bls.gov/regions/mountain-plains/summary/blssummary_cheyenne.pdf

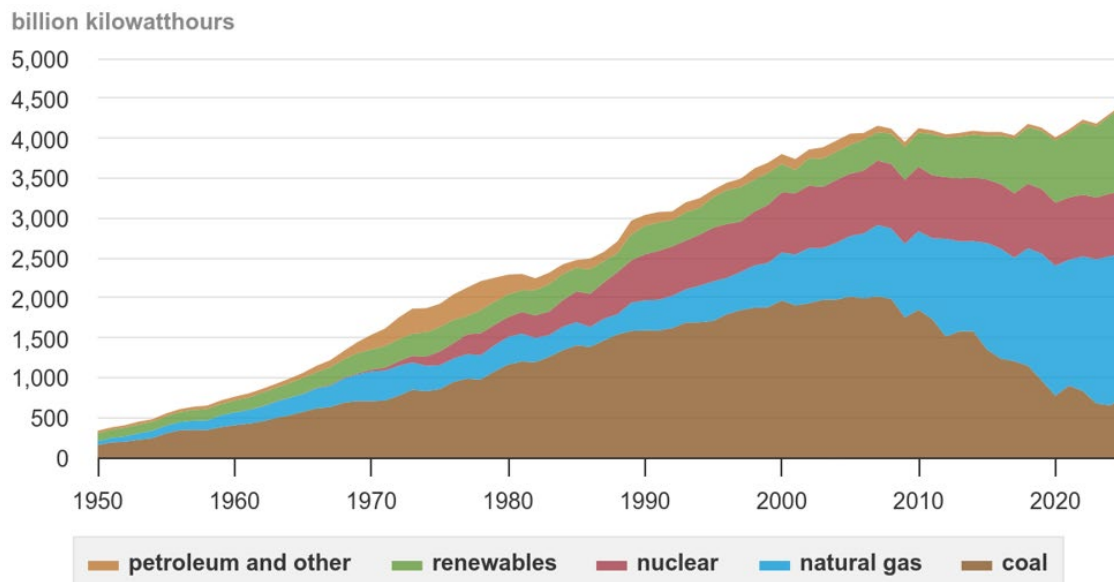
⁹ Source: <https://www.wyomingeconomicdata.com/wp-content/uploads/Annual-Trends-Report-2025-1.pdf>

2.8.1 Coal Trends

Historically, domestic base load energy was provided by coal-fired generation in the US. Nationally, that trend reversed in 2007. Since then, coal has given way to increased natural gas and renewable generation. By 2025, national coal generation dropped to the same level as 1972.

Figure 02-1 depicts the generation trend for the US over the past 76 years as published by the United States Energy Information Administration (“EIA”) in March 2026.

Figure 02-1
United States Electricity Generation by Major Energy Source¹⁰



An area of long-term concern in the use of coal as a fuel for electricity generation is that it produces more CO₂ emissions per unit of energy output than other fuels (about twice as much as natural gas). Because of policy, market, and societal forces, coal currently faces competitive pressure from lower-carbon resources such as natural gas, renewable resources, and other emerging technologies. Despite these competitive pressures, existing coal-fired generation remains the largest producer of electricity for Cheyenne Light (55 percent).

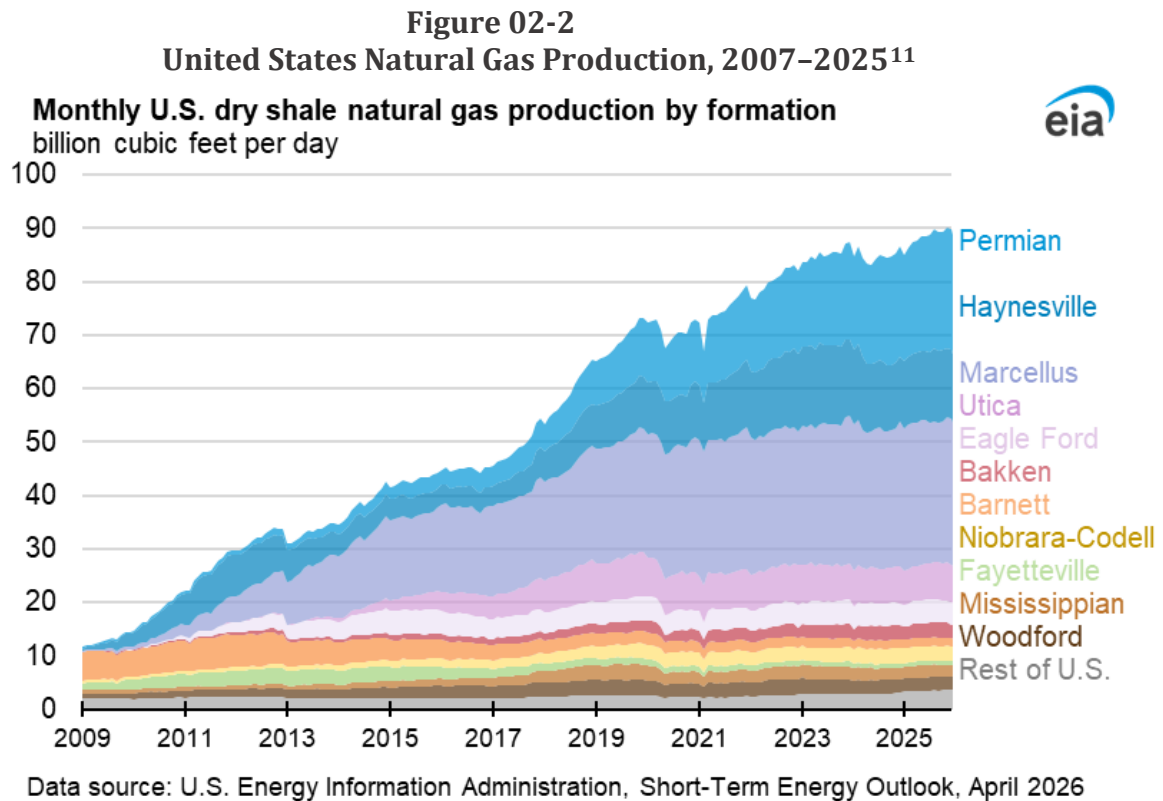
2.8.2 Natural Gas Supply Trends Over the Long-Term

Shale gas technology has increased the amount of recoverable North American natural gas, enabling producers to access vast supplies of shale gas. New technology

¹⁰ <https://www.eia.gov/energyexplained/electricity/electricity-in-the-us.php>

that provided lower cost access to shale gas caused total U.S. production to grow substantially.

Figure 02-2 illustrates the production of natural gas in the US.



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

2.8.3 Current Natural Gas Supply

The Black Hills Energy Gas Supply team procures natural gas for all of Cheyenne Light's natural gas-fired generating units. The team purchases and establishes risk mitigation measures, and contracts services for transporting and storing natural gas. Black Hills Energy's Generation 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.

Natural gas generation is dispatched by Cheyenne Light as needed by its customers. In order to meet the natural gas generation forecasts, Cheyenne Light purchases

¹¹ <https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php>

natural gas in the day-ahead market to meet expected customer electric energy requirements and generation dispatch for the following day. Actual consumption, however, may be higher or lower than forecasted based on the needs for the natural gas generation. The differences in actual versus forecasted natural gas consumption are settled through a balancing process with the pipeline company.

Cheyenne Light currently contracts for a total of 2,900 dekatherms per day of firm transportation of natural gas on the Southern Star Central Gas Pipeline (“SSCGP”) for the CPGS units. Cheyenne Light holds interruptible transportation contracts for incremental flow when demand of the CPGS units exceed 2,900 dekatherms. The interruptible transportation contracts have proved to be reliable. Because these contracts are interruptible 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.

When the non-firm natural gas supply is not available, the utilities rely on energy purchases from the electric power energy market to ensure system reliability. Since the cost of firm gas supply and transportation in this area can be expensive, the utilities rely on the geographic diversity of their generating assets to help reduce risk by ensuring gas supplier diversity. Because Cheyenne Light has 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.

2.8.4 Natural Gas Supply Risk Analysis and Mitigation Planning

Maintaining a reliable supply of natural gas becomes increasingly important as Cheyenne Light transitions their fuel supply from coal to natural gas and renewable resources. The utility continues 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 and can positively or negatively impact natural gas supply and cost. Based on these risks, Cheyenne Light will evaluate and may implement risk mitigation changes to their current gas supply practices.

Cheyenne Light will evaluate gas supply practices and consider a number of gas supply options, including securing more firm transportation capacity, to manage the future risks and to ensure safe, cost-effective, reliable energy supply.

Liquefied Natural Gas (“LNG”): LNG provides an alternative to natural gas from interstate pipelines LNG is delivered by truck 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.

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 agree to purchase natural gas in the summer at the prevailing fixed price, then from November through March, the utilities 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 pays 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. With proper technology enhancements, gas fired CTs can be 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. Additionally,

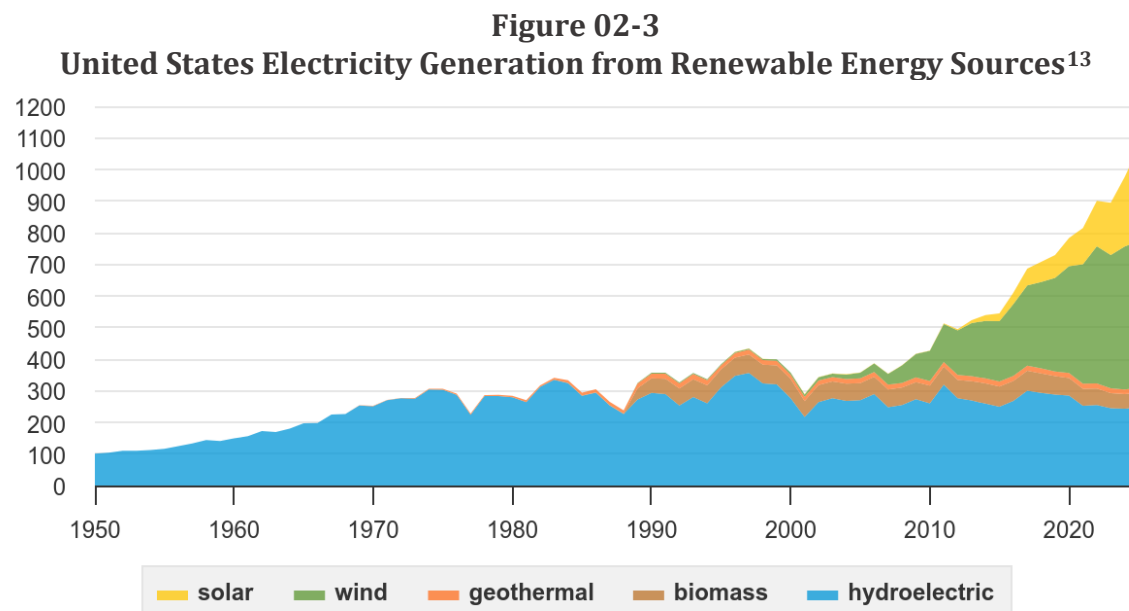
certain types of coal fired generators can be capable of running on coal or natural gas.

Cheyenne Light understands 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, including securing more firm transportation capacity, and will continue to communicate any revised practices in future IRPs.

2.8.5 Renewable Generation Trends

Since the 1990s, in the US the amount and percent of energy from renewable resources—biofuels, geothermal, solar, and wind—has increased close to three-fold to about 9 percent of national generation. The EIA projects that nation-wide renewable energy generation will continue to increase through 2050.¹²

Figure 02-3 depicts the renewable generation trend in the US over the past 75 years as published by the EIA in March 2026.



2.9 Energy Efficiency and Demand-Side Management

Demand Side Management (“DSM”) presents opportunities for energy conservation and efficiency. The reduction of capacity and energy can be achieved through

¹² <https://www.eia.gov/outlooks/aeo/narrative/>

¹³ <https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php>

implementation of DSM plans, consistent with goals approved by the Commission. Plans can be composed of residential and non-residential (commercial and industrial) programs. Each program addresses the needs of various customers.

Cheyenne Light continues to seek ways to reduce retail system peak demand through DSM plans. These include a combination of energy efficiency, conservation, and load management. Cheyenne Light's tri-annual DSM plan, originally implemented for 2016–2018, was renewed for 2019–2021 and again for 2022–2024. Based on the best information available at the time, the 2022–2024 plan is included in this 2026 IRP. For the 2025–2027 DSM plan, a one-year extension was granted by the Wyoming PSC and a revised plan for 2026–2028 was filed on July 1, 2025. On January 27, 2026, the Wyoming PSC issued an Order to Withdraw, at the request of Cheyenne Light, and endorsed a series of community stakeholder meetings to be held through Q2 of 2026 to provide community education and gather public input.

Cheyenne Light offered four residential DSM programs and three commercial and industrial DSM programs during the 2022–2024 implementation cycle. As discussed above, the 2025–2027 DSM program was only in place for 2025 and offered the same types of programs.

2.10 Federal Tax Incentives for Wind, Solar, Storage, and Carbon Capture

The One Big Beautiful Bill of 2025 P.L. 119-21 ("OB3") modified tax incentives for wind, solar, storage and carbon capture that were enacted or extended by the Inflation Reduction Act of 2022, P.L. 117-169 ("IRA"). The OB3 repealed production tax credits ("PTC") and investment tax credits ("ITC") for wind and solar projects that either begin construction after July 4, 2026 or are placed in service after 2027.¹⁴ Previously under the IRA, wind and solar projects were eligible for full value of PTCs or ITCs, if construction began before 2033.

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

The OB3 modified carbon capture tax credits for CO₂ that is used in EOR to be equal to the tax credit for CO₂ that is securely stored underground. Previously the tax credit was \$60/MT of CO₂ captured when used in EOR compared to \$80/MT when the CO₂ was securely stored underground. Now the tax credit for EOR is \$80/MT (referred to as "45Q tax credits" in this IRP).

¹⁴ Wind and Solar Projects that begin construction after July 4, 2026 must be placed in service by December 31, 2027.

The prevailing wage and apprenticeship rules that were enacted by the IRA still apply to PTCs, ITCs and carbon capture tax credits.

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

For carbon capture projects, no credit is allowed for taxable years beginning after enactment if the taxpayer is a PFE and no credit is allowed for taxable years that begin two years after the date of enactment for a foreign influenced entity, including ownership stakes, the ability to appoint a board member or executive officers, or certain contractual arrangements. The material assistance from PFE rules do not apply to carbon capture tax credits.

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 has been met with an increasing interest across the electric utility industry for proposals deploying battery storage.

2.11 The Power Supply Market

Power market transactions yield two main economic efficiencies. They ensure 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 Cheyenne Light operates and plans generation requirements. At times, the utility can purchase less expensive energy through market purchases to serve short-term customer needs (rather than generate energy from utility owned generation). Such purchases reduce costs and result in 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 generating unit. When the economy energy market price is less expensive, GDPM purchases it to satisfy demand; otherwise, they start up the generating unit. GDPM considers unit start-up costs, variable operation and maintenance expenses, ramp rates, and heat rates in these evaluations.

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

Weather, overall economic conditions, and resource supply availability—all of which can change quickly—drive demand uncertainties in the electricity markets. North American Reliability Corporation’s (“NERC”) 2025 Long-Term Reliability Assessment (“LTRA”)¹⁵ includes over 41,000 circuit miles of planned transmission over the next ten years, as well as many planned additions of natural gas, storage, wind, and solar resources. As such, WECC-Rocky Mountain has anticipated adequate capacity through 2033 and will require additional resources beginning in 2034 to meet rapid increases in forecasted demand.

2.12 Balancing Authorities

Prior to April 1, 2026, Western Area Power Administration Colorado Missouri (“WAPA,” “WACM”) was the Balancing Authority (“BA”) for Cheyenne Light and Black Hills Power. The WAPA Rocky Mountain Region (“WAPA RMR”) operated the WACM BA. On April 1, 2026, Black Hills Power began providing BA services for itself and a number of other electric utilities, including Cheyenne Light. Cheyenne Light is a transmission owner and transmission provider with its own open access transmission tariff; however, ancillary services are procured from the Black Hills BA under a balancing authority agreement.

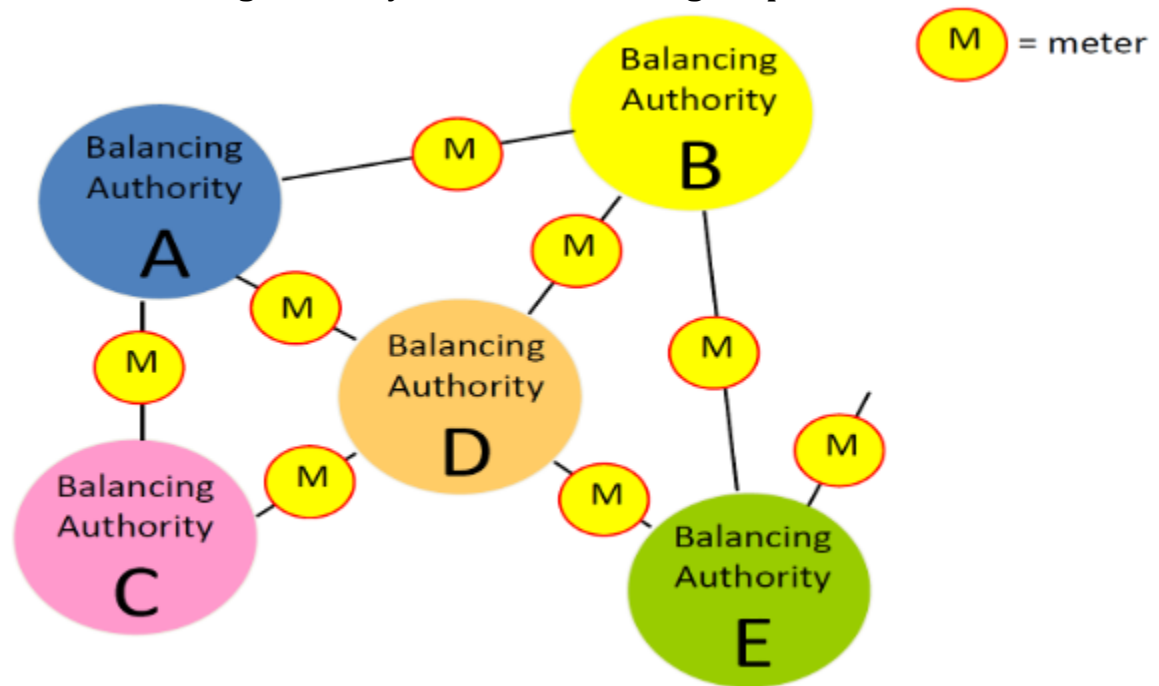
The Energy Policy Act of 2005 made compliance with NERC reliability standards mandatory for all electric utilities. A set of those reliability standards require that all load and generation under NERC jurisdiction be within the electrical boundaries of a BA. WECC conducts routine audits of the BAs to ensure they comply with all applicable NERC standards. A BA electrical boundary is determined by a set of resources and interchange meters.

The primary responsibility of the BA is to balance the load within its electrical boundary with transfers (energy imports and exports) and generation, to contribute to the effective control of electrical frequency across the Western Interconnect. Short term balancing is focused on load-frequency regulation whereas long term balancing focuses on load and variable resource following. BAs utilize automatic generator control (“AGC”) to adjust generator output over short time periods to provide these balancing services.

Figure 02-4 depicts a diagram of the BAs and their metered interchanges.

¹⁵ https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf

**Figure 02-4
Balancing Authority Metered Interchange Depiction**



2.12.1 Balancing Authority Services

On November 29, 2023, WAPA informed its BA service customers that it had signed an implementation agreement with the Southwest Power Pool (“SPP”) to join its Regional Transmission Organization (“RTO”) on April 1, 2026. Upon entry into the SPP RTO, the RTO would become the BA for all its Western Interconnection members and the WAPA BA would no longer provide BA services. The practical implications of WAPA’s decision to Cheyenne Light and Black Hills Power is that they would be required to either find an alternative BA service provider, establish their own BA, or join the SPP RTO.

At a December 6, 2023, meeting, SPP advised that it needed a decision from all WAPA BA customers whether they would be joining the SPP RTO no later than April 1, 2024. Black Hills asked SPP for an extension of time to make their decision, which SPP agreed to extend until April 15, 2024. Consequently, Black Hills Power and Cheyenne Light had roughly four months to decide if they were going to join the SPP RTO and only 24 months to assess their options, make a decision, and complete a full BA transition if they didn’t join the RTO.

The utilities analyzed each of the BA service options available to them following the WAPA announcement to find a solution that would be viable in 2026 with a high level of certainty, provide benefit to customers, and future flexibility as the wholesale market picture in the Western Interconnect becomes clearer. These options included joining the SPP RTO, taking services from a 3rd-party BA provider, or establishing a

new Balancing Authority to encompass the Black Hills Power and Cheyenne Light transmission systems.

The option to join the SPP RTO was challenging to evaluate given the lack of important information to guide that analysis, including an unknown planning reserve margin, uncertainty regarding the timeline and transition plan for large generator interconnection queues and processes, the process for requesting and transitioning existing transmission service, as well as other unknown RTO implementation details.

Several third-party BA providers were evaluated to provide BA services for Black Hills Power and Cheyenne Light, a similar arrangement to the services provided by WAPA today¹⁶. Each third-party BA provider was found to be infeasible or declined to provide BA services due to the long timeline to integrate into the third-party BA, given the short remaining time in the WACM BA, or the estimated cost and unavailability of transmission service needed to receive the services.

The direction that was selected was to establish a new BA which provided the greatest level of certainty for Black Hills Power and Cheyenne Light.¹⁷ This option was selected due to the ability to timely respond to Wyoming customer needs and to continue to maintain reliable operations. The new Black Hills BA was fully implemented on April 1, 2026.

2.12.2 Balancing Authority Regulation and Frequency Response Requirements

As a NERC-certified Balancing Authority effective April 1, 2026, Black Hills Power is responsible for maintaining continuous real-time balance between load, generation, and scheduled interchange within its Balancing Authority Area and for supporting interconnection-wide frequency control. These obligations are met through Regulation and Frequency Response (“RFR”) Service, an Ancillary Service required under Schedule 3/3A of Black Hills Power’s Open Access Transmission Tariff and mandated by NERC Reliability Standard BAL-001-2. RFR Service consists of two distinct components: Fast-Moving reserves, which respond to minute-to-minute deviations between actual net load and a 15-minute centered moving average, and Load-Following reserves, which respond to sustained intra-hour changes in net load between 15-minute scheduling intervals. Together, these components ensure compliance with NERC balancing authority area control error (“ACE”) limits and the ability to maintain interconnection frequency.

Based on one-minute Supervisory Control and Data Acquisition (“SCADA”) data for the 2024 test year and methodologies consistent with Federal Energy Regulatory Commission (“FERC”) precedent, the Black Hills BA carries a total Regulation and

¹⁶ Cheyenne Light’s 2021 IRP contained an analysis of three BA Options available to Cheyenne Light and Black Hills Power and contained a Balancing Authority Feasibility Study in Appendix G to the IRP.

¹⁷ Black Hills Power filed a notice documenting this decision.

Frequency Response requirement of 142.6 MW, consisting of 70.3 MW of Fast-Moving reserves and 72.3 MW of Load-Following reserves. Using a cost-causation-based fair allocation methodology, this total requirement is assigned among four rate classes based on each class's contribution to system variability: approximately 30.8 MW associated with load, 2.6 MW associated with non-variable generation, 37.1 MW associated with wind generation, and 72.1 MW associated with solar generation. Variable energy resources do not provide RFR service and instead increase reserve requirements due to their inherent variability, while non-variable, dispatchable generating resources are relied upon to supply the necessary regulating capacity through automatic generation control. Energy storage resources can provide RFR benefits through quick dispatch ability and frequency control, resulting in improved grid stability. These reserve obligations are met using portions of the existing generation fleet and are recovered through FERC-jurisdictional Ancillary Service Schedules 3 and 3A.¹⁸ Over time, participation in broader real-time imbalance energy markets is expected to moderate future RFR requirements by allowing load and resource variability to be balanced over a larger geographic footprint.

2.12.3 Real-Time Energy Market Participation

On April 1, 2023, Cheyenne Light joined the SPP-operated Western Energy Imbalance Service ("WEIS") real-time energy market. The WEIS market is a 5-minute energy market designed to reduce the output of high-priced generation and increase the output of low-priced generation to reduce the cost of purchases and increase the revenue of sales, all while maintaining the balance between load and generation and respecting transmission system limits. CLFP's expectation, based on the Western Joint Dispatch Agreement ("WJDA"), was that if that if RTO Expansion ("RTOE") efforts materialized, SPP would use commercially reasonable efforts to develop functionality for multi-market optimization between the SPP RTO real-time balancing market and remaining WEIS participants. However, market optimization did not occur between WEIS and RTOE, and SPP has since terminated the WEIS coincident with the SPP RTO Expansion go-live, effective April 1, 2026.

Appreciating the value that a real-time imbalance energy market provides through potentially lower energy costs for customers due to market depth and as a tool to aid in maintaining reliability within a BA, Black Hills committed to joining the California Independent System Operator's ("ISO," "CAISO") Western Energy Imbalance Market ("WEIM") with a go-live date of May 1, 2026.

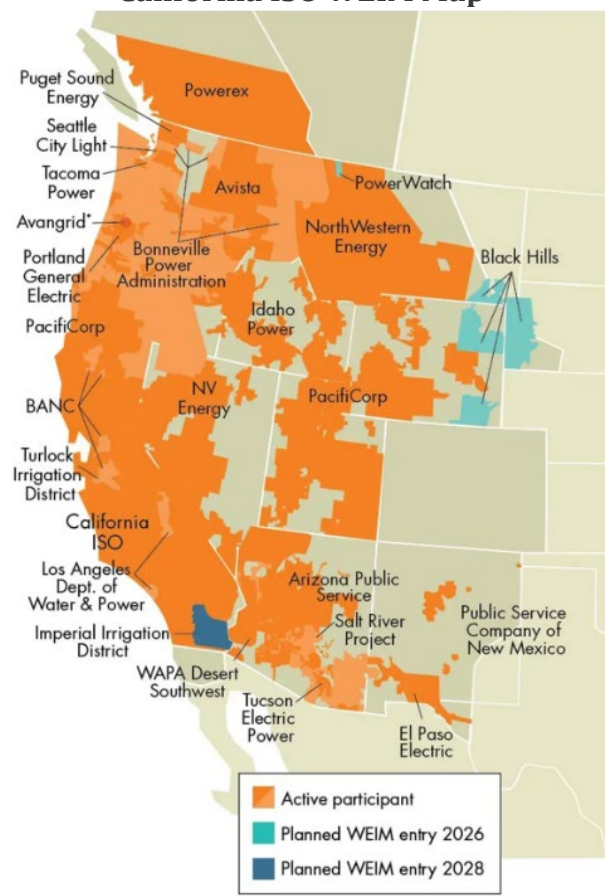
The WEIM began financially binding operation on November 1, 2014, by optimizing resources across the ISO and PacifiCorp Balancing Authority. Since then, the WEIM has continued to grow and now includes 22 market participants and represents nearly 80% of the demand for electricity in the Western interconnection. Today, the

¹⁸ [etariff.ferc.gov/TariffBrowser.aspx?tid=2860](https://www.ferc.gov/TariffBrowser.aspx?tid=2860) See tariff rates in Section 3.a - BHP Transmission Service Tariff

WEIM footprint includes portions of Arizona, California, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming, Texas and extends to the border with Canada, as shown in Figure 02-5. The WEIM provides potential customer savings through:

- More efficient use of the regional transmission system,
- Enhanced reliability via increased operational visibility across electricity grids and improving the ability to manage transmission line congestion across the markets high-voltage transmission system.

**Figure 02-5
California ISO WEIM Map**



Integrating into the WEIM will continue, and possibly expand, the value that Black Hills Power and Cheyenne Light customers have realized through participation in the similar, but smaller footprint, WEIS real-time imbalance energy market.

Black Hills engaged The Brattle Group to perform a study that evaluated the potential relative value of a Black Hills BA joining the WEIM or continuing participation in the WEIS following the implementation of the SPP RTO in the western interconnection in 2026. The study was undertaken before SPP announced the WEIS market would be

terminated. The study results did not incorporate or estimate the cost of transmission service across the SPP RTO transmission system to allow WEIS transfers between the Black Hills and Public Service Company of Colorado (“PSCO”) BAs – the two BAs that were assumed to continue participating in the WEIS. The Brattle study results estimated that a Black Hills BA participation in the WEIM would provide greater customer benefits than WEIS from an energy supply perspective, as shown in Table 02-2.

Table 02-2
WEIM and WEIS Annual Energy Saving Summary

WEIS	WEIM
\$1.1M	\$4.7M

These study results are reasonable as WEIM has a much broader geographic footprint that reflects greater load and resource diversity due to 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.

2.12.4 The Role of Transmission to Capture Customer Benefits

Despite the inherent challenges to establishing a new BA, Black Hills Power and Cheyenne Light are well positioned for the transition into the CAISO WEIM to maintain, and potentially expand, the value customers have realized through participation in the SPP WEIS. The closest WEIM participating BA is the PacifiCorp eastern BA primarily located in Utah and Wyoming. Black Hills Power has a number of existing transmission interconnections with PacifiCorp to facilitate WEIM market transfers.

With the completion of the Ready Wyoming project Cheyenne Light now has a direct connection to PacifiCorp as well as a transmission interconnection with Black Hills Power which facilitates its participation in the WEIM.

3. MODELING APPROACH AND ASSUMPTIONS

Ten modeling scenarios and three sensitivities were analyzed for Cheyenne Light. Candidate resource portfolios were developed, and a least-cost, least-risk resource portfolio was identified. From that, a preferred resource plan was selected for Cheyenne Light.

Many data assumptions and inputs are required to complete the load forecast and modeling for the IRP. Among others, assumptions must be made for the Planning Period, Near Term Need, planning reserves, and financial parameters. In addition, fuel price and market price forecasts must be input into the model for all types of generic resources as well as for existing resources. Selected assumptions are also

varied in the scenarios, such as the price of natural gas or load growth, to test the risks associated with specific inputs. Cheyenne Light's key assumptions and inputs are discussed below.

For this IRP, the Company is using resource planning models developed with the assistance of a third-party consulting firm, 1898 & Co., a part of Burns & McDonnell, ("1898"). Specifically, Cheyenne Light retained 1898 to complete the modeling work necessary for the IRP, including use of Yes Energy's EnCompass capacity expansion ("CE") and production cost modeling ("PCM")¹⁹ resource planning software. Benefits of the modeling software used by 1898 include optimizing investment and operational decisions while capturing least-cost portfolios and analyzing risk. 1898 is well suited for the modeling undertaking represented by the IRP, given its experience in multiple integrated resource planning efforts for other utilities.

3.1 Foundational Planning Elements

3.1.1 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 thermal and renewable resources, while maintaining system flexibility and complying with environmental laws and regulations.

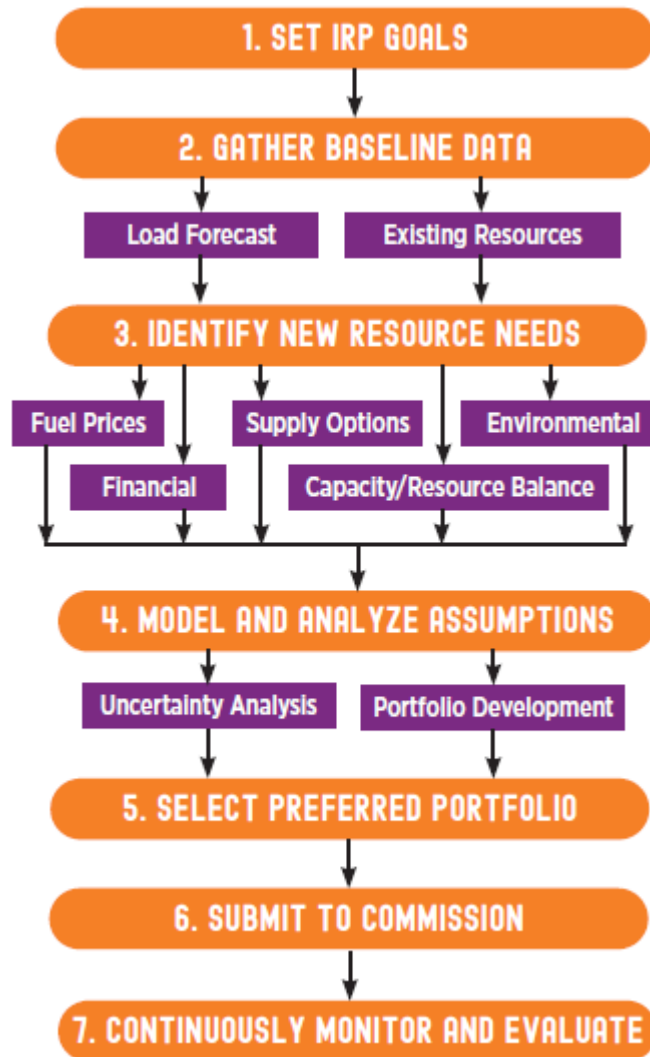
To develop the IRP, Cheyenne Light:

- 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 plan that meets forecasted needs.

Figure 03-1 details the IRP process in a flowchart.

¹⁹ Please see Confidential Appendix I for a technical description of the EnCompass modeling.

**Figure 03-1
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:

- CLFP Busbar Cost Study (Confidential Appendix D)
- Black Hills Reserve Margin and ELCC Study Report (Appendix E)
- Overview of Load Forecasting Models (Appendix G)

The IRP developed numerous scenarios and sensitivities. These scenarios and sensitivities 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 impacts, and

financial assumptions. Common risks and uncertainties were addressed through sensitivity analysis.

3.1.2 IRP Process Guidelines

3.1.2.1 Wyoming Commission IRP Rules

The Wyoming Commission's *Chapter 7: Integrated Resource Plan Rules* sets forth in Section 6.(a)-(b) the required contents for inclusion in the development of an IRP filed with the Commission. The assumptions, modeling, and analysis presented in this IRP have satisfied all applicable rules, and will be addressed in detail in testimony as well as within the Chapter 7 Integrated Resource Plan Rules Compliance Matrix Table attached to the Direct Testimony of Amanda Thames. As a part of the initial application process, Cheyenne Light has requested an IRP filing cadence of every three years for approval. While Black Hills Energy operates in other state jurisdictions, Cheyenne Light does not have any interjurisdictional state allocation agreements to report.

Current regulatory requirements under state and federal law are described in Sections 2.1 through 2.5. Many of these requirements will continue to be monitored and filings submitted accordingly to ensure compliance. For this IRP, the only requirement modeled was for carbon capture compliance (Section 2.1.1) and its corresponding assumptions are described in Section 8.5.

3.1.2.2 Stakeholder Process

Cheyenne Light held a meeting with the Wyoming Commission Staff and the Wyoming Office of Consumer Advocate ("OCA") to discuss various aspects of the development of the IRP on September 15, 2025 and develop a more robust IRP process. Informational discussions have also occurred throughout the planning process to engage key stakeholders. In addition, Cheyenne Light presented the IRP generally at a Technical Conference to the Commission Staff and OCA on June 3, 2026. Informational discussions have also occurred throughout the planning process to engage key stakeholders.

3.2 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 2026 through 2045.

A near-term need planning period must provide adequate time to acquire the necessary resources to meet customers' electricity needs. The IRP is based on an eight-year near-term need planning period, addressing the years 2026–2033, which includes the years in which the IRP identified additional resources to meet Cheyenne Light's capacity needs. This short-term planning period exceeds the Near-Term Need

as identified by the PSC IRP Rules in Chapter 7, Section 3(h) which states it is “a subset of the Action Plan items determined necessary for the Affected Electric Utility to meet its short-term, i.e., zero to six years, load forecast”. The eight year short-term planning period includes the expiration of the Wygen I PPA (December 31, 2032) to ensure that any identification of additional resources takes this expiration into consideration in the selection of the preferred portfolio.

3.3 Strategic Decisions and Goals

The goal of the IRP is to develop a portfolio that minimizes costs 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 forces²⁰, 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 everchanging technological developments and evolving energy needs and preferences.

Through the IRP process, the IRP team developed over two dozen candidate resource options.²¹ The team modeled and analyzed the candidate resource options against a wide range of scenarios and sensitivities to select a preferred plan for Cheyenne Light. The preferred plan continues to modernize the power grid to maintain the high level of reliability customers enjoy.

3.4 Modeling Scenarios and Sensitivities

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

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

²⁰ Described in Section 2. Planning Environment.

²¹ See Section 5. Supply-Side Resources for a description of each candidate resource.

3.5 Modeling Inputs and Assumptions

3.5.1 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 Plan options contained median forecasts for all assumptions. Specific subsets of those assumptions were varied in the Low Gas, High Gas, Low Load, and High Load scenarios to test the risk associated with each specific assumption. Additional scenarios were designed to reflect more specific risks and resource needs resulting from the inclusion of LPCS load and resources, as well as alternative resource impacts from carbon capture options.

3.5.2 Planning Reserve Margin

Reliability means securing capacity equal to the forecasted demand plus an additional percentage reserve margin to meet daily peak demand. The reserve margin is based on thermal capacity, capacity factors of renewable resources, and a rigorous analysis of system characteristics. The system characteristics include load shape, 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.

A study completed by PowerGEM, LLC (“PowerGEM”) utilized a Loss of Load Expectation (“LOLE”) methodology, where a single load loss event in ten years (referred to as “1-in-10”) identified a 13 percent Perfect Capacity (“PCAP”) planning reserve margin as being sufficient to meet reliability requirements. This is discussed in more detail in Section 6 as well as Appendix E.

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

(“MISO”)²² and SPP²³ also employ seasonal PRMs due to technology-specific reliability differences. Industry benchmarks reflect a wide range of PRM outcomes, including Total Reliability PRMs of 32.5 to 35.9 percent in the 2025 Western Assessment of Resource Adequacy (“WARA”) PRMA²⁴ and PRMs ranging from 30.5 percent in 2023 to 6.9 percent in 2035 in the 2025 NERC LTRA.²⁵ Black Hills continues to monitor industry developments, including energy assurance and computational load risks, while evaluating methodologies best suited to its system.

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

3.5.3 Fuel and Market 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 a 25-year electricity price forecast created by Energy Strategies, LLC (“Energy Strategies”) in 2025 for natural gas and energy price forecasts.²⁶ Coal forecasts are based on internal analysis.

3.5.3.1 Natural Gas Price Forecasts

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

Table 03-1 lists the price ranges for Energy Strategies’ Henry Hub natural gas prices from the beginning and ending years of the planning period for the natural gas scenarios. The scenario forecasts are also listed in Appendix H.

²² <https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2003%20PY%202025-2026%20LOLE%20Study%20Results654956.pdf>

²³

<https://www.spp.org/documents/76399/2025%20lola%20study%20prm%20recommendation.pdf>

²⁴

<https://www.wecc.org/sites/default/files/documents/products/2025/2024%20PRM%20Analysis.pdf>

²⁵ NERC, 2025 Long-Term Reliability Assessment, page 35.

²⁶ See Appendix H – CLFP Price and Cost Forecasts for the schedules of all fuel price forecasts.

Table 03-1
Average Annual Henry Hub Gas Price Forecasts

Scenario	Henry Hub 2026 Price (\$/MMBtu)	Henry Hub 2045 Price (\$/MMBtu)
Base Natural Gas	3.72	4.70
Low Natural Gas	2.11	2.90
High Natural Gas	4.08	8.60

3.5.3.2 Coal Price Forecasts

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

Table 03-2 lists the delivered coal price forecast for the planning period. The price forecast is also shown in Appendix H.

Table 03-2
Annual Delivered Coal Price Forecasts

Scenario	Coal 2026 Price (\$/MMBtu)	Coal 2045 Price (\$/MMBtu)
Base Forecast	1.14	1.85

3.5.3.3 Economy Energy Price Forecasts

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

Economy market energy may be available at significant cost savings. For Cheyenne Light, the IRP incorporated an option to purchase economy energy for up to 15 percent of load in every hour.

Table 03-3 lists the ranges of the blended AZ-PV/Mid-C market area on and off-peak pricing from the beginning and ending years of the planning period for the natural gas scenarios. More information can be found in Appendix H.

Table 03-3
Average Annual AZ-PV/Mid-C Price Forecasts

Scenario	AZ-PV/Mid-C 2026 Price (\$/MWh)	AZ-PV/Mid-C 2045 Price (\$/MWh)
Base Natural Gas	31.33	19.76
Low Natural Gas	22.77	14.19
High Natural Gas	33.48	31.36

3.5.3.4 Nuclear Price Forecasts

Black & Veatch provided an annual delivered nuclear price forecast for the base scenario.

Table 03-4 lists the nuclear price for the applicable planning horizon. The forecast can also be found in Appendix H.

Table 03-4
Annual Delivered Nuclear Price Forecasts

Scenario	Nuclear 2030 Price ²⁷ (\$/MMBtu)	Nuclear 2045 Price (\$/MMBtu)
Base Forecast	3.14	4.31

3.5.3.5 Seasonal Firm Market Purchased Power Price Forecasts

Cheyenne Light makes 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. Cheyenne Light makes these purchases instead of procuring additional resources and use the purchases to meet short-term capacity needs to better manage customer costs.

The IRP assumes Cheyenne Light will be able to purchase seasonal firm market power. This measure can be used to cover peak demand shortfalls up to 50 MW and is assumed to be available six days per week, sixteen hours per day (7 am to 11 pm),

²⁷ Nuclear pricing begins in 2030 aligning with when nuclear resources are available for selection in the capacity expansion modeling. Nuclear resources span years of development due to the long lead times associated with construction and regulatory approvals.

which is consistent with experience transacting with counterparties in the west. In addition, the NERC 2025 Summer Reliability Assessment²⁸ and NERC 2025 Long-Term Reliability Assessment²⁹ indicate sufficient capacity is available in the region in the short term. The WECC-Rocky Mountain area is above the reference margin level through the IRP's NTN, indicating sufficient capacity and energy are available. NERC indicates the area is at risk of experiencing increasing loss of load hours during the end of their ten-year planning period due to increased demand, resource retirements and increases in renewable resources. The area falls below their reference margin level beginning in 2034, indicating not enough resources have progressed into the interconnection queue for the later years of the assessment period.

The model is able to select the seasonal firm market power in 25 MW blocks, up to a total of 50 MW(two blocks) during on-peak hours throughout the NTN. This seasonal firm market power is priced at Energy Strategies' 2025 Electricity Price Forecast using the Palo Verde price forecast, plus a 20 percent firmness premium, and incorporates an additional wheeling adder.

Table 03-5 lists the price ranges of Palo Verde on-peak market area before any premiums or adders are included from the beginning and ending years of the planning period. They are also available in Appendix H.

Table 03-5
Average Annual AZ-PV Price Forecasts

Scenario	AZ-PV 2026 Price (\$/MWh)	AZ-PV 2045 Price (\$/MWh)
Base Natural Gas	30.08	12.06
High Natural Gas	32.10	18.64
Low Natural Gas	22.14	8.84

3.5.4 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 or sensitivity.

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 35-year book-life for combined cycle and peaking technologies, 25 years for wind, solar, coal

²⁸ https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2025.pdf

²⁹ NERC, 2025 Long-Term Reliability Assessment, page 35.

to gas conversions and coal to carbon capture conversion, and 20 years for battery storage. Tax lives used were 20 years for combined cycle, coal to gas conversion, and coal to carbon capture conversion, 15 years for peaking technologies, 7 years for battery storage and 5 years for solar and wind.

Table 03-6 presents these financial assumptions.

Table 03-6
Modeled Financial Assumptions

Assumptions	Cheyenne Light
Discount Rate	7.48%
Cost of Debt	5.02%
Cost of Equity	9.75%
Rate of Escalation (Inflation Rate)	2.31%
Capital Structure	
Equity	52%
Debt	48%
Property Tax Rate	.338%
Combined Cycle (35-year fixed charge rate with 20-year tax life)	8.93%
Peaking technology (35-year fixed charge rate with 15-year tax life)	8.78%
Coal to gas/Carbon capture (25-year fixed charge rate with 20-year tax life)	9.83%
Wind/Solar (25-year fixed charge rate with 5-year tax life)	9.15%
Battery Storage (20-year fixed charge rate with 7-year tax life)	10.10%
First Year Recovery Rate	
CC/CT/Other New	1.89%
Conversions/Wind/Solar/CC	3.00%
Battery Storage	3.99%
Annual Construction Escalation	2.31%

3.5.5 Demand Side Management

After the econometric modeling for each base forecast is complete, additional adjustments are made to produce the final forecasts. One adjustment is the inclusion of the effects of Demand Side Management plans. 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.

In 2021, Cheyenne Light filed to renew its tri-annual DSM plan for the years 2022–2024. 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 2022–2024 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.

Figure 03-2 depicts the energy efficiency goals from 2011 through 2025 for Cheyenne Light.

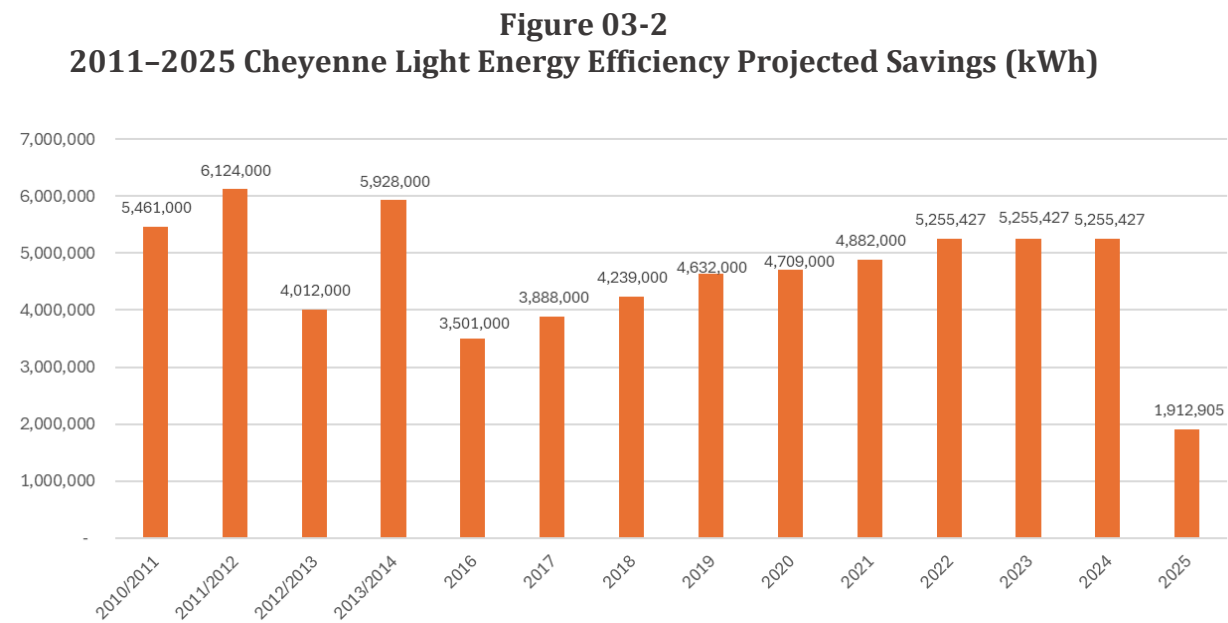


Table 03-7 compares the forecasted peak savings with the actual saving for each year of Cheyenne Light’s 2022-2024 DSM Plan. Load forecasts for this IRP were adjusted to include the forecasted reductions in both the peak demand and energy forecasts.

Table 03-7
Cheyenne Light Tri-Annual DSM Plan Projected and Actual Savings 2022-2024

DSM Plan Year	Projected Peak Savings (MW)	Actual Peak Savings (MW)	Projected Energy Savings (MWh)	Actual Energy Savings (MWh)
2022	1.035	0.42	5,255	2,025
2023	1.035	0.705	5,255	2,222
2024	1.035	0.247	5,255	1,019

The 2025 DSM plan was filed with the Commission in 2024. The projected and actual savings are depicted in Table 03-8. Any future savings from this plan will be incorporated as appropriate in future IRP analysis.

Table 03-8
Cheyenne Light 2025 DSM Plan Projected and Actual Savings

DSM Plan Year	Projected Peak Savings (MW)	Actual Peak Savings (MW)	Projected Energy Savings (MWh)	Actual Energy Savings (MWh)
2025	0.509	0.547	1,913	2,265

Table 03-9 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.

Table 03-9
Cheyenne Light DSM-Related Load Forecast Adjustments: 2026–2045

Year	Projected Peak Savings (MW)	Projected Energy Savings (MWh)
2026	2.17	10,511
2027	2.17	10,511
2028	2.17	10,511
2029	2.17	10,511
2030	2.17	10,511
2031	2.17	10,511
2032	2.17	10,511
2033	2.17	10,511
2034	2.17	10,511
2035	2.17	10,511
2036	2.17	10,511
2037	2.17	10,511
2038	2.17	10,511
2039	2.17	10,511
2040	2.17	10,511
2041	2.17	10,511
2042	2.17	10,511
2043	2.17	10,511
2044	2.17	10,511
2045	2.17	10,511

4. LOAD FORECAST

In large part, annual peak and energy load forecasts determine 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, economics, and weather data. These datasets were used to develop the monthly system-level peak demand forecast and the major customer class energy forecasts. The IRP developed base, low, and high load forecasts, as well as ITS and LPCS load forecasts. ITS is applicable to large industrial power users whose total minimum capacity requirements are 13,000 kW or greater and taking service at transmission voltage level service. LPCS is applicable to large power users whose expected capacity requirement is 18,000 kW or greater, as they must maintain loads under the ITS Rate Schedule in addition to a minimum of 5,000 kW served under the LPCS Rate Schedule. Examples of such customers are data centers.

The starting point for IRP modeling and analysis is deriving 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 base retail peak demand and energy. Cheyenne Light gathered and refined a variety of different types of datasets, including historical load, historical weather, and historical and projected economic data.

These datasets were used to develop regression forecasts for the base retail monthly peak demand forecast and energy forecasts. The final system-level monthly peak demand forecast was computed by including energy efficiency planned effects and large customer load forecasts, including anticipated future load growth or reductions, to the base load forecast produced from the econometric analysis. The final system-level major customer class energy forecasts were computed by including energy efficiency planned effects, large customer load forecasts, including their anticipated future load growth or reductions, as well as transmission and distribution losses to the base energy forecasts calculated through the econometric analysis. The IRP developed base, low, high, and ITS and LPCS load forecasts.

4.1 Econometric Model Overview

Econometric modeling was used as the foundation for the system-level demand and major customer class level energy forecasts. The econometric forecasts were

developed using the statistical software package Stata³⁰. The IRP process utilized this software to develop statistical regression forecasts that estimate the effect of various factors (for example, weather) on customer energy, the number of customers served, and system peak demand. The explanatory factors used in these equations consist of weather, electricity prices, demographic variables, and economic variables.

The advantages of econometric forecasting models include:

- The ability to estimate effects of specific drivers on energy and demand, thus 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 models to reflect changing circumstances over time.
- The use of third-party weather, economic, and demographic data in the forecast, remove potential concerns about biased inputs.
- Providing measures as to the statistical precision of the estimates, such as the statistical significance of a particular driver variables or the overall explanatory power of the forecast model.

Econometric forecasting models reveal relationships between energy (or demand or the number of customers served) and economic or demographic variables to forecast future developments. The process begins by estimating the historical relationship between 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, energy) are then applied to forecasts relative to the drivers to develop the forecast energy, 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).

4.2 Load, Economic, and Weather Data

4.2.1 Historical Load Data

The IRP utilizes historical system-level hourly load data to produce the demand forecast. The demand data was gathered and reviewed to ensure accuracy. The energy forecast utilizes historical customer class level monthly load data. The major customer class energy forecasts were developed using historic energy and customer count. Energy 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). Historical lighting service data and company-usage data were removed before conducting the energy forecast modeling to ensure the

³⁰ Please see Appendix G - Overview of Load Forecasting Models for the detailed analysis completed by Christensen Associates Energy Consulting, LLC.

customer class energy growth rates were not skewed by the historical growth patterns for these sectors. The excluded data for lighting and company use were added to the aggregated energy forecast after the major class forecast models were complete.³¹

4.2.2 Economic Data

Economic and demographic historical and forecast data were obtained from Woods & Poole Economics, Inc. for Laramie County in Wyoming. 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 the mean of real household total personal income, total number of households, total employment, and gross regional product. Each of these variables was tested in the regression analysis.³²

4.2.3 Weather Data

Historical weather data was collected from the NOAA National Climatic Data Center's Cheyenne Airport weather station. 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.

4.2.4 Normal Weather Conditions

The weather variables in the energy and demand forecasts were set to reflect normal conditions, calculated as the average weather conditions over a set of historical years. In the energy forecast, normal weather is defined as the average of the monthly total cooling degree days and heating degree days over the previous 20 years. In the peak demand model, each month's peak conditions were first categorized as either predominantly cooling- or heating-based. The normal peak weather conditions were then averaged over only the relevant day types (i.e., cooling-based or heating-based), including only the peak and near-peak hours for each month and year. The years included in the peak demand normal weather

³¹ The historical load and energy data used in the peak demand and energy models are included in Confidential Appendix C, Schedule C-1 and Schedule C-2.

³² The historical and forecasted economic data used in the peak demand and energy forecasts are included in the Confidential Schedule C-3 of Confidential Appendix C.

calculations for Cheyenne Light spanned 23 years. In order to forecast energy or demand, the most recent historical (observed) data was weather normalized and then the forecasted economic, demographic, and/or trend effects (as applicable) during the forecast years was applied to those normalized values. That is, if the forecasted energy growth trend was +1 percent, the first forecast year would have energy 1 percent higher than the weather normalized energy from the most recent observed month.

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

4.3.1 Peak Demand Forecast Methodology

Cheyenne Light's system-level demand forecast is 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. Large customers with ITS, LPCS, and Blockchain Interruptible Service ("BCIS") loads were removed from the system-level data prior to the regression analysis. ITS and LPCS loads are forecasted separately and described in Sections 4.3.3 and 4.5, respectively. The IRP's base retail demand load forecast excludes LPCS and BCIS loads for Cheyenne Light, and furthermore, BCIS loads are not included in any load forecast or scenario within the IRP.

4.3.2 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 commercial general service primary. 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 and commercial contracts rate IDs which used to constitute the industrial class, are now forecasted separately in Section 4.3.3 below. Large customers with ITS loads are forecasted separately under the large customer forecast section below as well. The IRP's base retail energy load forecast excludes LPCS and BCIS loads for Cheyenne Light. LPCS loads are described in Section 4.5 as they were forecasted and included in additional load scenario

analyses as identified in Section 8 (BCIS loads not forecasted or included within this IRP).³³

4.3.3 Large Customer Growth Assumptions

A further refinement to the final load forecasts is the inclusion of large volume customer forecasts. Cheyenne Light periodically reviews the growth plans of the largest customers in its service territory. These load additions or reductions encompass growth greater than the anticipated growth rates included in the econometric load forecasts. These expected load increases can be uncertain and depend, in part, on broader 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. Table 04-1 lists the anticipated demand (MW) growth and reductions for Cheyenne Light's Large Volume Customers ("LVC") that were incorporated into peak demand and energy load forecasts.

Table 04-1
Cheyenne Light's LVC Load Forecast 2026-2033 (MW)

Year	Customer 1	Customer 2	Customer 3
2026	-7	1	4
2027	3	1	4
2028	3	4	4
2029	3	2	4
2030	3	2	4
2031	3	2	4
2032	3	2	4
2033	3	2	4
Average Load Factor (%)	91%	87%	92%

Table 04-2 lists Cheyenne Light's anticipated ITS customer peak demand forecast for the near-term planning period. The ITS load is a sub-grouping of large customers and is considered retail load that is incorporated into base forecast.

³³ Summaries of the final energy and demand equations are described in Appendix G. Also included in Schedules C-1, C-2, and Confidential C-3 of Confidential Appendix C, are the historical and forecasted values for variables that were used in the models. The resulting monthly and annual forecasts for all customer classes are in Schedules C-10 and C-11 of Confidential Appendix C.

Table 04-2
Cheyenne Light's ITS Customer Load Forecast 2026–2033

Year	Demand (MW)
2026	23
2027	50
2028	50
2029	50
2030	50
2031	50
2032	50
2033	50
Average Load Factor (%)	95%

4.4 Final Base Peak Demand and Energy Forecasts

The final base system-level monthly peak demand forecast was computed by including energy efficiency planned impacts and anticipated future load growth or reductions of base retail industrial and ITS customers into the load forecast calculated by the regression analysis. The final system-level major customer class energy forecasts were computed by including energy efficiency planned impacts, anticipated future load, including growth and reductions, of base retail industrial and ITS customers, lighting service loads, and company use loads, to the energy forecasts calculated through the regression analysis. Cheyenne Light's final system-level peak demand and energy forecasts excluded all LPCS and BCIS loads.

Combined transmission and distribution energy losses were also added into the monthly energy forecast for the Cheyenne Light system. The system level transmission and distribution loss factors used in the base retail energy forecasts are outlined in Table 04-3 below. Separate system loss estimates cannot be made for transmission and distribution because the losses forecast was not developed at the transmission and distribution voltage level.

Table 04-3
Expected Transmission and Distribution Line Losses for Cheyenne Light

Energy Customer Class	Average Estimated T&D Losses
Residential	7.56%
Commercial No Demand	7.56%
Commercial General Service Secondary	7.56%
Commercial General Service Primary	6.44%
Large Volume Customer	3.50%
ITS Customer	3.50%
Company Use	7.56%
Lighting	7.56%

Table 04-4 lists the peak demand and annual energy forecasts values for the base load forecasts.

Table 04-4
Cheyenne Light's Final Base Forecasts

Year	Cheyenne Light	
	Peak Demand (MW)	Annual Energy (MWh)
2026	234	1,362,361
2027	256	1,517,831
2028	261	1,550,670
2029	262	1,542,680
2030	264	1,545,372
2031	266	1,548,010
2032	268	1,550,597
2033	270	1,553,139
2034	272	1,555,645
2035	274	1,558,124
2036	277	1,560,588
2037	279	1,563,035
2038	281	1,565,468
2039	283	1,567,879
2040	285	1,570,271
2041	287	1,572,664
2042	289	1,575,076
2043	292	1,577,506
2044	294	1,579,949
2045	296	1,582,392

4.5 Low, High, and LPCS Forecasts

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

The IRP models low and 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 energy forecasts was modeled.³⁴ The forecast represents the energy 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 occur, or a period of sustained growth could occur. The confidence interval indicates the extent to which demand and energy can vary because of such uncertainties.

Cheyenne Light's high load forecast also includes an additional 50 MW step load increase beginning in 2027. Similarly, Cheyenne Light's low load forecast includes an additional 20 MW step load decrease beginning in 2027. These step forecasts are designed to capture the potential variability associated with several large customers.

In addition to the low and high load forecasts, Cheyenne Light also created an LPCS load forecast to address the impacts of contracting and serving existing and potential large load data center customers, including only customers who currently have agreements in place. The LPCS load forecast was developed and included in the IRP to allow for the evaluation of scenarios that included both traditional base retail load and LPCS load. The preferred portfolio recommended by Cheyenne Light does not provide capacity resources for use by LPCS customers. The LPCS customers are obligated to manage and pay for their own capacity resources under the provisions of the LPCS rate schedule. Similar to large industrial customers, Cheyenne Light periodically reviews growth plans of the LPCS customers in its service territory. These reviews identify potential load changes beyond those captured in econometric forecasts, with anticipated large-customer additions informed by economic development input. Transmission and distribution line losses of 3.5% were added to the LPCS energy forecast. These changes in LPCS customer loads are only reflected in the LPCS peak demand and energy load forecasts.

Table 04-5 lists Cheyenne Light's anticipated LPCS customer peak demand forecast for the near-term planning period.

³⁴ The specific steps used to develop the confidence interval are described in Appendix G.

Table 04-5
Cheyenne Light's LPCS Customer Load Forecasts 2026–2033

Year	Demand (MW)
2026	200
2027	450
2028	550
2029	600
2030	600
2031	650
2032	650
2033	650
Load Factor (%)	95

Table 04-6 details the base, low, high, and base + LPCS summer peak demand and the annual energy load forecasts for the planning period for Cheyenne Light. These forecasts include the impact of energy efficiency programs.

Table 04-6
Cheyenne Light's Peak Demand and Annual Energy Load Forecasts

Cheyenne Light Peak Demand and Annual Energy								
Year	Summer Peak Demand (MW)				Annual Energy (GWh)			
	Base	Low	High	Base + LPCS	Base	Low	High	Base + LPCS
2026	217	210	224	417	1,362	1,352	1,373	3,071
2027	256	227	315	706	1,518	1,333	1,961	5,231
2028	261	231	322	811	1,551	1,363	1,996	6,261
2029	262	229	324	862	1,543	1,353	1,991	6,610
2030	264	230	328	864	1,545	1,353	1,996	6,824
2031	266	230	332	916	1,548	1,354	2,000	7,110
2032	268	231	337	918	1,551	1,354	2,005	7,113
2033	270	231	341	920	1,553	1,355	2,010	7,115
2034	272	231	345	922	1,556	1,355	2,014	7,118
2035	274	232	349	924	1,558	1,356	2,019	7,120
2036	277	232	354	927	1,561	1,356	2,024	7,123
2037	279	233	358	929	1,563	1,357	2,028	7,125
2038	281	233	362	931	1,565	1,357	2,033	7,128
2039	283	233	367	933	1,568	1,358	2,037	7,130
2040	285	234	371	935	1,570	1,358	2,041	7,133
2041	287	234	376	937	1,573	1,359	2,046	7,135
2042	289	234	380	939	1,575	1,359	2,050	7,137
2043	292	235	385	942	1,578	1,359	2,055	7,140
2044	294	235	389	944	1,580	1,360	2,060	7,142
2045	296	235	394	946	1,582	1,360	2,064	7,145

Table 04-7 details the base, low, high, and base + LPCS summer peak demand and winter peak demand forecasts for the planning period for Cheyenne Light. These forecasts include the impact of energy efficiency programs.

**Table 04-7
Cheyenne Light's Seasonal Peak Demand Comparison**

Cheyenne Light Seasonal Peak Demand								
Year	Summer Peak Demand (MW)				Winter Peak Demand (MW)			
	Base	Low	High	Base + LPCS	Base	Low	High	Base + LPCS
2026	217	210	224	417	234	228	241	534
2027	256	227	315	706	242	214	300	792
2028	261	231	322	811	247	217	307	797
2029	262	229	324	862	247	216	309	847
2030	264	230	328	864	249	217	313	899
2031	266	230	332	916	251	217	317	901
2032	268	231	337	918	253	217	321	903
2033	270	231	341	920	255	218	325	905
2034	272	231	345	922	257	218	329	907
2035	274	232	349	924	259	218	333	909
2036	277	232	354	927	261	219	337	911
2037	279	233	358	929	263	219	341	913
2038	281	233	362	931	265	219	345	915
2039	283	233	367	933	267	220	349	917
2040	285	234	371	935	269	220	353	919
2041	287	234	376	937	271	220	357	921
2042	289	234	380	939	273	221	361	923
2043	292	235	385	942	275	221	366	925
2044	294	235	389	944	277	221	370	927
2045	296	235	394	946	279	222	374	929

4.6 Alternative ITS and LPCS Forecasts

The final base load forecast is intended to represent a central estimate of future load, with actual outcomes potentially varying from the midpoint in any given year. Due to the magnitude of the ITS and LPCS customers' load forecasts, Cheyenne Light produced alternative ITS and LPCS load forecasts to evaluate the impact of these potential deviations.

To address the rapidly growing data center load and uncertainty for what portion will be served as ITS versus LPCS load, alternative forecasts were developed. The ITS load forecast was increased from 50 MW to 75 MW, and the LPCS load forecast was decreased by the same amount.

Table 04-8 lists Cheyenne Light’s alternative ITS, base CLFP with the alternative ITS load, alternative LPCS, and resulting alternative base CLFP + alternative LPCS (alternative base +LPCS) peak demand and energy forecasts for the planning horizon.

**Table 04-8
Alternative Load Forecasts 2026–2045**

Year	Peak Demand (MW)				Annual Energy (GWh)			
	Alt ITS	Alt CLFP	Alt LPCS	Alt CLFP + LPCS	Alt ITS	Alt CLFP	Alt LPCS	Alt CLFP + LPCS
2026	48	242	200	442	461	1,575	1,530	3,105
2027	75	281	450	731	613	1,731	3,465	5,196
2028	75	286	550	836	621	1,764	4,570	6,334
2029	75	287	550	837	621	1,756	4,781	6,537
2030	75	289	600	889	621	1,758	5,136	6,895
2031	75	291	600	891	621	1,761	5,279	7,040
2032	75	293	650	943	621	1,764	5,562	7,326
2033	75	295	650	945	621	1,766	5,562	7,329
2034	75	297	650	947	621	1,769	5,562	7,331
2035	75	299	650	949	621	1,771	5,562	7,334
2036	75	302	650	952	621	1,774	5,562	7,336
2037	75	304	650	954	621	1,776	5,562	7,338
2038	75	306	650	956	621	1,779	5,562	7,341
2039	75	308	650	958	621	1,781	5,562	7,343
2040	75	310	650	960	621	1,783	5,562	7,346
2041	75	312	650	962	621	1,786	5,562	7,348
2042	75	314	650	964	621	1,788	5,562	7,351
2043	75	317	650	967	621	1,791	5,562	7,353
2044	75	319	650	969	621	1,793	5,562	7,355
2045	75	321	650	971	621	1,795	5,562	7,358

4.7 Historical Peak Demand and Annual Energy

Cheyenne Light has historically experienced peaks in the summer. Typically, summer peaks are higher than winter peaks. Table 04-9 details the annual summer peak demand and annual energy for 2020–2025.

**Table 04-9
Historical Peak Demand and Annual Energy**

Year	Peak Demand		Annual Energy		Load Factor (%)
	Summer (MW)	% Change	GWh	% Change	
2020	227		1,463		73%
2021	223	-2%	1,393	-5%	71%
2022	231	4%	1,441	3%	71%
2023	245	6%	1,596	11%	74%
2024	223	-9%	1,520	-5%	78%
2025	220	-1%	1,408	-7%	73%
Average Annual Growth (%)		0%		-1%	

Historical values include 35 MW of ITS load, 0 MW of BCIS load, and 0 MW of LPCS load. Annual energy includes transmission and distribution losses. Since 2020, Cheyenne Light has experienced an average annual peak demand growth rate of 0 percent, and the historical annual energy experienced an average annual growth rate of -1 percent.

Table 04-10 compares the projected peak demand and annual energy amounts from the last Cheyenne Light IRP. In the 2021 CLFP IRP, the base CLFP (without ITS customers) demand growth rate from 2026-2033 was 0.8%, the LVC demand forecast included approximately an 11 MW decrease in 2030, and the ITS demand load forecast included 35 MW. On the contrary, in the 2026 CLFP IRP, the base CLFP (without ITS customers) demand growth rate from 2026-2033 was 1.1%, the LVC demand forecast included approximately a 9 MW increase in 2030, and the ITS demand load forecast included 50 MW. The primary drivers listed here explain the main differences in the load forecasts between the two plans.

Table 04-10
Cheyenne Light Forecasted Peak Demand and Annual Energy Comparison

Year	2021 IRP		2026 IRP	
	Peak Demand (MW)	Annual Energy (MWh)	Peak Demand (MW)	Annual Energy (MWh)
2021	215	1,351,043	-	-
2022	224	1,418,053	-	-
2023	225	1,422,976	-	-
2024	226	1,419,010	-	-
2025	225	1,401,578	-	-
2026	229	1,423,319	217	1,362,361
2027	231	1,425,366	256	1,517,831
2028	233	1,427,324	261	1,550,670
2029	234	1,429,203	262	1,542,680
2030	236	1,430,984	264	1,545,372
2031	238	1,432,618	266	1,548,010
2032	239	1,434,109	268	1,550,597
2033	241	1,435,509	270	1,553,139
2034	242	1,436,862	272	1,555,645
2035	244	1,438,208	274	1,558,124
2036	245	1,439,533	277	1,560,588
2037	247	1,440,769	279	1,563,035
2038	248	1,441,903	281	1,565,468
2039	250	1,442,976	283	1,567,879
2040	251	1,444,052	285	1,570,271
2041	-	-	287	1,572,664
2042	-	-	289	1,575,076
2043	-	-	292	1,577,506
2044	-	-	294	1,579,949
2045	-	-	296	1,582,392

5. SUPPLY-SIDE RESOURCES

The Cheyenne Light current resource mix includes firm generation fired by natural gas and coal, and renewable generation from wind. Candidate resource options considered by the IRP modeling encompasses firm generation from Reciprocating Internal Combustion Engine (RICE) units, simple cycle and combined cycle combustion turbines; renewable generation from wind, solar, and battery storage;

nuclear generation; retrofitting existing resources including conversion to gas and deploying carbon capture technology; and seasonal firm market purchases.

5.1 Cheyenne Light Current Generation Supply Resources

Cheyenne Light serves customers through a combination of owned generation and power purchase agreements. These resources are fueled by coal, natural gas, and wind.

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.

The generation mix of Cheyenne Light consists of owned, co-owned generation, and PPAs for firm generation and renewable sources. Cheyenne Light's generation resources consist of one wholly-owned coal-fired plant (Wygen II), one wholly-owned natural gas simple cycle CT, one partly-owned natural gas combined cycle CT, one partly-owned wind facility, plus PPAs for a coal-fired power plant (Wygen I) and two wind facilities. See Table 05-1 for a summary of CLFP's resource types.

Table 05-1
Cheyenne Light Total Generation Mix

Resource	Fuel	MW	Owner	Location	Start	End/ Retire
Cheyenne Prairie SCCT	Natural Gas	37	Cheyenne Light 100%	Cheyenne	2014	-
Cheyenne Prairie CCCT	Natural Gas	40	Cheyenne Light 42% (Black Hills Power 58%)	Cheyenne	2014	-
Wygen II	Coal	90	Cheyenne Light 100%	Gillette Energy Complex	2008	-
Corriedale	Wind	20	Cheyenne Light 38% (Black Hills Power 62%)	Cheyenne	2020	-
Wygen I PPA*	Coal	60	Black Hills Wyoming	Gillette Energy Complex	2001	2032
Happy Jack PPA	Wind	13.65	Deriva Energy Generation Services	Cheyenne	2008	2028
Silver Sage PPA	Wind	10	Deriva Energy Generation Services	Cheyenne	2009	2029
Total		270.65				

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

Currently, Cheyenne Light utilizes generating resources capable of producing 187 MW and has PPAs for another 83.65 MW of power for its customers. The IRP assumes all existing PPAs are not renewed or extended beyond their current expiration dates. Modeling assumptions for CLFP's existing resources are provided in Table 05-2. Nameplate capacity is considered to be equivalent to rated capacity. The summer and winter capacities are considered dependable capacity based on the ELCC accreditations. The expected annual availability is dependent on the timing of major scheduled overhauls as well as forced outages.

Table 05-2
Modeling Assumptions for Cheyenne Light's Generation Mix

Generation	Nameplate/ Contract Capacity (MW)	Summer Capacity (MW)	Winter Capacity (MW)	Forced Outage Rate (%)	Scheduled Outage Rate (%)	Ave Heat Rate (Btu/kWh)
Wygen II	90	72	69	3	Varies	12,033
Cheyenne Prairie CCCT	40	32	31	3	Varies	7,002
Cheyenne Prairie SCCT	37	30	28	3	Varies	8,207
Happy Jack PPA	13.65	4	4	0	0	N/A
Silver Sage PPA	10	3	3	0	0	N/A
Corriedale	20	6	6	0	0	N/A
Wygen I PPA	60	48	46	3	Varies	11,956

5.2 Gillette Energy Complex

Two generation stations for Cheyenne Light are sited at the Gillette Energy Complex: Wygen I and Wygen II. The Wyodak mine is part of the complex. The supply of coal from the mine located adjacent to the coal-fired plants eliminates high fuel transportation costs. Together, these units provide up to 150 MW of power to CLFP. The Gillette Energy Complex is depicted in Figure 05-1.

**Figure 05-1
Gillette Energy Complex**



5.2.1 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 near Gillette, Wyoming 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 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. This IRP considers solutions through the contract expiration and incorporates its impacts into the selected future portfolios.³⁵

5.2.2 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 near Gillette, Wyoming. The power plant, wholly owned by Cheyenne Light, obtains all its fuel from the adjacent Wyodak coal mine, which keeps fuel costs low. The Wygen II facility is depicted in Figure 05-2.

³⁵ See Section 8 - Portfolio Analysis and Selection.

Figure 05-2
Wygen II and Wygen III Generation Facility



5.3 Cheyenne Prairie Generating Station

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

5.3.1 Simple Cycle Combustion Turbine

The CPGS facility consists of two combustion turbines units. Cheyenne Light owns the simple cycle CT ("SSCT"), which is a 37 MW unit. CLFP's simple cycle is depicted in Figure 05-3.

Figure 05-3
Cheyenne Prairie Generating Station Simple Cycle CT



5.3.2 Combined Cycle Combustion Turbine

The CPGS facility also consists of a 95 MW combined cycle CT ("CCCT"). Cheyenne Light owns 42 percent of the combined cycle unit (40 MW) and Black Hills Power owns the remaining 58 percent (55 MW). CLFP's combined cycle is depicted in Figure 05-4.

Figure 05-4
Cheyenne Prairie Generating Station Combined Cycle CT



5.4 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, Wyoming, 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). The Corriedale Wind facility is depicted in Figure 05-5.

Figure 05-5
Corriedale Wind Facility



5.5 Happy Jack Wind Facility

The Happy Jack wind facility, wholly owned by Deriva Energy, is located in Cheyenne, Wyoming. Commissioned on September 3, 2008, the facility consists of thirteen 2.1 MW turbines for a maximum capacity of 27.3 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. The Happy Jack PPA will expire during Cheyenne Light's near-term planning period on September 4, 2028. This IRP considers solutions through the contract expiration and incorporates its impacts into the selected future portfolio.³⁶ The Happy Jack Wind facility is depicted in Figure 05-6.

**Figure 05-6
Happy Jack Wind Facility**



5.6 Silver Sage Wind Facility

The Silver Sage wind facility, wholly owned by Deriva Energy, is located in Cheyenne, Wyoming. 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.. The Silver Sage PPA will expire during Cheyenne Light's near-term planning period on September 30, 2029. This IRP analyzes resource solutions through the contract expiration and incorporates its impacts into the selected future portfolio. ³⁷

5.7 Market Purchases

The company's Generation Dispatch and Power Marketing (GDPM) department transacts the market purchases necessary to fulfill Cheyenne Light's obligations for managing and procuring energy. GDPM also secures market purchases for third-party utilities and large customers.

GDPM regularly transacts with multiple counterparties in a number of regions, including but not limited to, the Northwest, Southwest, Rockies, and SPP. GDPM manages long-term, seasonal firm, and economy market purchases for energy. The

³⁶ See Section 8 - Portfolio Analysis and Selection.

³⁷ See Section 8 - Portfolio Analysis and Selection.

department continually reviews and adjusts purchasing strategy and energy mix to better capture favorable market conditions.

5.8 LPCS Current Generation Supply Resources

Cheyenne Light also serves several LPCS customers with a resource mix of customer-owned generation, customer PPAs, and market energy. The LPCS generation resources consist of PPAs for one wind (Roundhouse II), one storage (Cowboy BESS), and two solar facilities (South Cheyenne Solar and Cowboy Solar). There is an additional 150 MW customer owned behind the meter (“BTM”) generation provided as back-up capacity. Table 05-3 summarizes the LPCS generation mix. For LPCS, the IRP incorporated an economy energy purchase of 15 percent of the load for every hour.

Table 05-3
Modeling Assumptions for LPCS Generation Mix

Generation	Nameplate/ Contract Capacity (MW)	Summer Capacity (MW)	Winter Capacity (MW)	Forced Outage Rate (%)	Scheduled Outage Rate (%)	Ave Heat Rate (Btu/kWh)	Start	End/ Retire
Roundhouse II Wind PPA	106	30	34	0	0	N/A	2023	2043
South Cheyenne Solar PPA	150	14	3	0	0	N/A	2024	2044
Cowboy Solar PPA	365	33	7	0	0	N/A	2027	2047
Cowboy BESS PPA	200	130	108	3	0	N/A	2027	2047
BTM Owned Generation ³⁸	150	N/A	N/A	N/A	N/A	N/A		2033

Currently, Cheyenne Light utilizes LPCS generating resources capable of producing 150 MW and has PPAs for another 821 MW of power for its customers. The IRP assumes all existing PPAs are not renewed or extended beyond their current expiration dates.

Table 05-4 lists the ranges of the blended AZ-PV/Mid-C market area on and off-peak pricing from the beginning and ending years of the planning period. More information can be found in Appendix H.

³⁸ The Customer Owned BTM Generation was modeled as a firm purchase through 2033 to simulate the operational commitments of these units as Eligible Capacity Resources under the LPCS rate schedule.

Table 05-4
Average Annual AZ-PV/Mid-C Price Forecasts

Scenario	AZ-PV/Mid-C 2026 Price (\$/MWh)	AZ-PV/Mid-C 2045 Price (\$/MWh)
Base Natural Gas	31.33	19.76
Low Natural Gas	22.77	14.19
High Natural Gas	33.48	31.36

5.9 Candidate Resource 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.

Cheyenne Light engaged Black & Veatch to perform a busbar study of candidate resource options. The busbar study analyzed 27 candidate resource options to determine resource options that should move forward to modeling. A technology level of 8 or higher was determined as adequate to move forward. These resources went through a screening process to determine the most viable resource options. The IRP modeled both fuel-fired and renewable resources and analyzed several resource characteristics such as capacity, capital cost, operating cost, and outage rates.³⁹

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 inclusive of owner's cost and 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.

Detailed descriptions of these candidate resource options follow and were available for selection for Cheyenne Light and LPCS scenarios.

5.9.1 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, Wyoming area at

³⁹ See Confidential Appendix D – CLFP Busbar Cost Study conducted by Black & Veatch.

greenfield sites. Performance assumptions and cost values for modeling conventional resources were taken from the CLFP Busbar Cost Study conducted by Black and Veach.

5.9.1.1 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.

Cheyenne Light uses its simple cycle CT for peaking, reserves, and quick-start and black-start capabilities. It is advantageous to continue to support these capabilities through the ownership of future resources having these same capabilities.

In this analysis, technology options modeled for simple cycle CTs included a RICE unit, a LM6000 PF+, and a FT4000. Table 05-5 lists the assumptions used to model each 1x0 CT option.

Table 05-5
Simple Cycle CT Modeling Assumptions

Assumption	RICE	LM6000 PF+	FT4000
Earliest Feasible Instillation	2029	2029	2029
Nominal Net Capacity (Net MW)	18	43	55
Summer Capacity (Net MW)	17	41	52
Winter Capacity (Net MW)	17	41	52
Full Load Heat Rate (Btu/kWh)	8,600	9,450	*
Forced Outage Rate (%)	2.5	1.6	*
Maintenance Outage Rate (%)	1.7	1.1	*
CO ₂ Emission Rate (lb/MWh)	1,020	1,130	*
Fixed O&M (2025 \$/kW-year)	26.8	174.74	*
Variable O&M (2025 \$/MWh)	2.04	0.78	*
Capital Cost (2025 \$/kW)	2,636	4,022	*

* See Confidential Appendix D for information pertaining to the FT4000 resource

5.9.1.2 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.

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 05-6 lists the assumptions for the 1x1, 2x1, and 3x1 combined cycle CT configurations.

Table 05-6
Combined Cycle CT Modeling Assumptions

Assumption	1x1	2x1	3x1
Earliest Feasible Instillation	2029	2029	2029
Nominal Net Capacity (Net MW)	77	155	232
Summer Capacity (Net MW)	75	106	225
Winter Capacity (Net MW)	75	106	225
Full Load Heat Rate (Btu/kWh)	7,800	7,700	7,750
Forced Outage Rate (%)	1.6	1.6	1.6
Maintenance Outage Rate (%)	1.1	1.1	1.1
CO ₂ Emission Rate (lb/MWh)	930	920	920
Fixed O&M (2025 \$/kW-year)	79.92	52.86	45.58
Variable O&M (2025 \$/MWh)	2.71	2.21	2.08
Capital Cost (2025 \$/kW)	3778	3474	3356

In addition, one large, combined cycle option—the 1x1 M501JAC CT—was included in the modeling. Table 05-7 lists the assumptions for the M501JAC combined cycle CT.

Table 05-7
M501JAC Combined Cycle CT Modeling Assumptions

Assumption	1x1
Earliest Feasible Instillation	2029
Summer Capacity (Net MW)	649
Full Load Heat Rate (Btu/kWh)	6,300
Forced Outage Rate (%)	1.6
Maintenance Outage Rate (%)	1.1
CO ₂ Emission Rate (lb/MWh)	760
Fixed O&M (2025 \$/kW-year)	19.82
Variable O&M (2025 \$/MWh)	1.47
Capital Cost (2025 \$/kW)	1,829

Accredited capacity values for candidate thermal resources were obtained from the effective load carrying capability analysis completed by PowerGEM.⁴⁰ The capacity contribution of thermal resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand over time. These values are not impacted by the penetration levels of resources, rather they are impacted by unit size and equivalent forced outage rate. For the purposes of portfolio selection, Cheyenne Light developed capacity-contribution values for two size ranges (less than 60 MW, greater than 60 MW) of thermal resources.

5.9.1.3 Small Modular Reactor

As a carbon-free firm resource, nuclear generation provides baseload clean energy while providing some flexibility to adjust load to match variable grid demands and renewable generation. While large light water reactor (“LLWR”) units are still being built internationally, LLWRs are starting to fall out of favor due to their large capital cost and long construction schedules. For these reasons, consideration for nuclear generation is given to Small Modular Reactors (“SMRs”) which are typically less than 300 MW. SMRs can be subdivided into Generation III+ (“Gen III+”) and Generation IV (“Gen IV”) advanced reactors. Gen III+ reactors are similar to the existing Gen III reactors but have advanced passive safety features that are incremental improvements from existing technology. Technology risks with Gen III+ reactors are low. Gen IV reactors are very different from the existing fleet and may still require technology and fuel development. Modeled SMRs assume ownership at a greenfield site. SMRs are expected to be commercially available as early as 2030.

Parameters used to model small modular reactor are shown on Table 05-8.

⁴⁰ See Appendix E - Black Hills Reserve Margin and ELCC Study Report.

Table 05-8
Small Modular Reactor Modeling Assumptions

Assumption	60 MW
Earliest Feasible Instillation	2030
Summer Capacity (Net MW)	60
Full Load Heat Rate (Btu/kWh)	10,500
Forced Outage Rate (%)	4.5
Maintenance Outage Rate (%)	8.2
CO ₂ Emission Rate (lb/MWh)	N/A
Fixed O&M (2025 \$/kW-year)	88.30
Variable O&M (2025 \$/MWh)	0
Capital Cost (2025 \$/kW)	15,000

5.9.2 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.

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 CLFP Busbar Cost Study completed by Black & Veatch.⁴¹

Accredited capacity values were obtained from the effective load carrying capability analysis completed by PowerGEM.⁴² 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 expected to decline as the penetration of resources of the same type increases. For the purposes of portfolio selection, Cheyenne Light developed capacity-contribution values for up to 500 MW of wind and solar penetration.

⁴¹ See Confidential Appendix D - CLFP Busbar Cost Study.

⁴² See Appendix E – Black Hills Reserve Margin and ELCC Study Report.

5.9.2.1 Photovoltaic Solar

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

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 stationary. 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 than 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.

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. Legislation related to investment tax credit levels for projects are no longer available and therefore not included in the modeling.

Table 05-9 lists the modeling assumptions for solar PV facilities.

Table 05-9
Photovoltaic Solar Modeling Performance Assumptions

Assumption	50 MW	100 MW	200 MW
Earliest Feasible Installation	2029	2029	2029
Capacity Factor (%)	21	21	21
Summer Capacity (Net MW)	2.8	4.9	8.2
Winter Capacity (Net MW)	0.1	0.2	0.3
Fixed O&M (2025 \$/kW-Year)	9.35	8.85	8.75
Variable O&M (2025 \$/MWh)	N/A	N/A	N/A
Capital Cost (2025 \$/kW)	1,776	1,704	1,610

5.9.2.2 Wind

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

A wind turbine shuts down when the wind is either too slow or too fast. 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.

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. Due to recent legislation, PTCs were not assumed to be available for the planning period and were not included as part of the modeling.

Table 05-10 lists the modeling assumptions for wind facilities.

Table 05-10
Wind Modeling Assumptions

Assumption	50 MW	100 MW	200 MW
Earliest Feasible Installation	2029	2029	2029
Capacity Factor (%)	48	46.8	45.8
Summer Capacity (Net MW)	8.4	16.5	31.6
Winter Capacity (Net MW)	9.7	19.2	36.9
Fixed O&M (2025 \$/kW-year)	27.40	20.97	20.23
Variable O&M (2025 \$/MWh)	N/A	N/A	N/A
Capital Cost (2025 \$/kW)	2,112	2,052	1,995

5.9.3 Energy Storage Options

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.

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. EnCompass' PCM model dispatches a battery storage resource to optimize energy used by the resource subject to constraints, such as storage-cycle efficiency and the daily balance of take and return energy. To determine the least-cost resource expansion plan, the PCM 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, 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.

Battery storage can be modeled in PCM purely as an arbitrage opportunity or can be paired with another generating unit that exclusively charges the battery. In both cases the battery attempts to charge during the lowest-priced hours in a day and discharge during the highest-priced hours. In this way batteries can provide peak saving benefits, as it will generally be the case that the highest-priced hours coincide with the system peak and when the battery is economically incentivized to discharge. The battery options modeled as part of this IRP used an algorithm that estimates marginal costs to determine economic charging and generating schedules. Battery storage options for the CLFP IRP were modelled as standalone (charged by the system). The BESS stations were modeled with a daily maximum energy equivalent to allow the resource to complete a full cycle once per day.

Accredited capacity values were obtained from the effective load carrying capability analysis completed by PowerGEM.⁴⁰ The capacity contribution of energy storage 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 expected to decline as the penetration of resources of the same type increases. For the purposes of portfolio selection, Cheyenne Light developed capacity-contribution values for up to 500 MW of energy storage penetration.

5.9.3.1 Battery Energy Storage System

The IRP modeling selects among three sizes of four-hour duration battery storage options: 50 MW, 100 MW, and 200 MW. All stand-alone options assume ownership at a greenfield site. The Cheyenne Light scenarios were limited to a maximum selection of 50 MW of BESS storage, while LPCS scenarios were modeled with unlimited MWs to coincide with system size. Due to recent legislation, ITCs were assumed to be available for battery storage during the planning period. The inclusion of ITCs is reflected in the capital cost as seen in the table below. Table 05-11 contains the assumptions used to model Battery Energy Storage Systems.

Table 05-11
Battery Storage Modeling Assumptions

Assumption	50MW	100MW	200MW
Earliest Feasible Installation	2029	2029	2029
Summer Capacity (Net MW)	50	95	165.5
Winter Capacity (Net MW)	34.6	63	103.3
Annual Forced Outage Hours	0	0	0
Maintenance Outage Rate	13.7	13.7	13.7
Fixed O&M (2025 \$/kW-year)	7.12	7.12	7.12
Variable O&M (2025 \$/MWh)	0.0	0.0	0.0
Capital Cost (2025 \$/kW)	1,816	1,575	1,466
Capital Cost w/ ITC (2025 \$/kW)	1,315	1,140	1,061

5.9.3.2 Long Duration Energy Storage

Long Duration Energy Storage (“LDES”) was also included as an option for modeling. LDES technologies are generally considered for 8+ hours of duration. Modeling included 50 MW 10-hour duration flow batteries. This Long Duration Energy Storage resource option was determined to have a technology readiness level of 8. Due to recent legislation, ITCs were assumed to be available for LDES options during the planning period. The inclusion of ITCs is reflected in the capital cost as seen in the table below. Table 05-12 contains the assumptions used to model LDES technologies.

Table 05-12
Modeling Assumptions for LDES Technologies

Assumption	50 MW 10-hour duration flow batteries
Earliest Feasible Installation	2029
Summer Capacity (Net MW)	50
Winter Capacity (Net MW)	34.6
Annual Forced Outage Hours	0
Maintenance Outage Rate	12
Fixed O&M (2025 \$/kW-year)	118
Variable O&M (2025 \$/MWh)	0
Capital Cost (2025 \$/kW)	5,900
Capital Cost w/ ITC (2025 \$/kW)	4,272

5.9.4 Retrofitting Existing Units

5.9.4.1 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 CLFP Busbar Cost Study, Confidential Appendix D, provided the cost and unit performance impacts of the potential conversion of the Wygen II power plant to gas. 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.

Table 05-13 contains the assumptions used to model Wygen II coal to gas conversion.

Table 05-13
Coal to Gas Modeling Assumptions

Assumption	Coal to Gas Conversion
Earliest Feasible Instillation	2030
Summer Capacity (Net MW)	86
Winter Capacity (Net MW)	86
Full Load Heat Rate (Btu/kWh)	12,300
Forced Outage Rate (%)	2.5%
Maintenance Outage Rate (%)	1.7%
CO ₂ Emission Rate (lb/MWh)	1,450
Fixed O&M (2025 \$/kW-year)	97.53
Variable O&M (2025 \$/MWh)	3.15
Capital Cost (2025 \$/kW)	677

5.9.4.2 Carbon Capture Addition to Existing Coal Plant

Carbon capture is the process of separating carbon dioxide (CO₂) from flue gas before it is released into the atmosphere. Sequestration is the process of storing captured CO₂ in a manner that prevents its return to the environment. Carbon capture utilization involves the beneficial use of captured CO₂; at large scale this typically involves pipeline transport for oil and gas development, while smaller markets include food and beverage applications (e.g., dry ice and carbonated beverages). Commercial post-combustion carbon capture systems are typically designed to achieve approximately 90 percent or greater CO₂ capture efficiency, which is the industry standard for economically viable sequestration projects and is consistent with systems supporting Class VI geologic storage applications.

For transport and storage, additional CO₂ conditioning is required. While Class VI injection regulations primarily address containment and protection of underground sources of drinking water, CO₂ transported by pipeline generally requires higher purity—typically 95 percent or greater, with some pipeline operators specifying 96–97 percent CO₂ concentration, along with stringent limits on moisture and other contaminants to ensure safe and reliable operation.

The most commercially mature post-combustion technology is amine-based absorption, which relies on chemical solvents to bind CO₂. This process requires a significant source of low-pressure steam for solvent regeneration, as well as additional auxiliary power and ongoing solvent management, increasing operating and maintenance requirements. The required steam and auxiliary power loads render smaller coal-fired generating units essentially non-dispatchable, with available capacity, minimum-to-maximum load inflexibility, and net generation potentially reduced to approximately half of prior capacity due to parasitic loads.

Post-combustion equipment can be retrofitted to existing power stations that were originally built without it. Depending on configuration, equipment typically includes an absorber, stripper, rich/lean solvent heat exchanger, flue gas cooler, condensate pumps, condenser, dryer, and compressors. Integration also requires tie-ins for steam supply to the amine process, associated attemperation to reduce high-pressure/high-temperature steam to low-pressure saturated steam, and condensate return systems. Operating the carbon capture system increases chemical consumables usage and waste disposal requirements.

As an alternative, Black Hills is actively evaluating and in the process of pilot testing a technology developed by Carbon GeoCapture. The paradigm shift pursued by Carbon GeoCapture focuses on where the CO₂ is ultimately injected. Their concept involves utilizing Class II wells to inject a range of CO₂ concentrations (approximately 40–60 percent) into unmineable coal seams for both carbon sequestration—as coal has a high affinity for CO₂ adsorption—and carbon utilization, as methane bound within the coal matrix is released when CO₂ molecules are adsorbed.

The lower CO₂ concentrations accommodated by the Carbon GeoCapture process have significant potential to reduce parasitic load, chemical demands, operations and maintenance costs, and operational inflexibilities commonly associated with amine-based CCS systems. In addition, the Carbon GeoCapture process is agnostic to the specific carbon capture equipment or technology used to concentrate the CO₂ stream.

The process being piloted through a partnership between Black Hills, Carbon GeoCapture, and the Wyoming Energy Authority will utilize membrane technology for the carbon capture portion of the system. Typical equipment for this approach is substantially simpler and involves far fewer components compared to amine-based systems, generally consisting of a blower, heat exchanger, membrane unit, and compressor, with the primary distinguishing technology being the specialized membrane that exhibits a preferential affinity for CO₂.

Carbon capture cost and unit performance impacts were developed as part of the busbar study and applied to Cheyenne Light's Wygen II coal unit. Although five carbon capture technologies were analyzed, only amine-based CCS was commercially ready at the time of the busbar analysis and the Carbon GeoCapture process was included but with some high-level cost sensitivities. As Black Hills continues partnerships with Carbon GeoCapture and evaluates pilot-testing results, future IRP studies will determine the potential for commercial application. Carbon capture analysis was also conducted to evaluate HB200 implications.

5.9.4.3 Wygen II Power Plant

The Wygen II power plant was selected for analysis of adding CCS technology under the House Bill 200 scenarios only. Cheyenne Light developed this scenario to investigate potential customer impacts of installing CCS 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 II⁴³. Carbon capture technology qualifies for the 45Q tax credits, and the model incorporated \$85/MT of carbon captured for the first 12 years after the facility is in service.

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, and do not account for the replacement power costs for the baseload unit. Costs for the compression of CO₂ and facility maintenance were included in the

⁴³ As part of the House Bill 200 scenario, Wygen II was converted to carbon capture in 2030 for compliance purposes. The model did not economically select this when given the option to convert to gas or convert to carbon capture.

fixed maintenance cost. Process waste disposal was included in the variable cost of the carbon capture equipment. For most of the carbon capture cases (amine-based and conservative Carbon GeoCapture-based) costs are representative of a total installed EPC cost and include sequestration costs. The amine case includes a pipeline allowance for tie into the Denbury pipeline for CO₂ sequestration while the membrane cases include sequestration in the licensor scope. To address some of the uncertainty of developing technology, Carbon GeoCapture was evaluated with different cost assumptions to capture cost sensitivities, where the lower cost case assumes owner-led execution.

Table 05-14 lists the assumptions for modeling the carbon capture related to the Wygen II power plant.

Table 05-14
Wygen II Carbon Capture Modeling Assumptions

Assumption	Wygen II Amine-Based CCS	Wygen II Carbon GeoCapture-Based CCS (Conservative)	Wygen II Carbon GeoCapture-Based CCS (Low-end)
Earliest Feasible Installation	2030	2030	2030
Summer Capacity (Net MW)	53.2	56.28	56.28
Winter Capacity (Net MW)	53.2	56.28	56.28
Full Load Heat Rate (Btu/kWh)	17,250	16,700	16,700
Forced Outage Rate (%)	2.5	3.2	3.2
Maintenance Outage Rate (%)	1.7	3.3	3.3
CO ₂ Emission Rate (lb /MWh)	207	378	378
Fixed O&M (2025 \$/kW-year)	279.39	405.18	316.63
Variable O&M (2025 \$/MWh)	N/A	N/A	N/A
Capital Cost (2025 \$/kW)	12,431	9,847	7,374

5.9.5 Seasonal Firm Market Purchased Power

Cheyenne Light makes 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.

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 will be able to purchase seasonal firm market power. This measure can be used to cover peak demand shortfalls up to 50 MW 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 2025 Summer Reliability Assessment⁴⁴ and NERC 2025 Long-Term Reliability Assessment⁴⁵ indicate sufficient capacity is available in the region in the short term.

The model is able to select the seasonal firm market power in 25 MW blocks, up to a total of 50 MW(two blocks) during on-peak hours throughout the NTN. This seasonal firm market power is priced at Energy Strategies' 2025 Electricity Price Forecast using the Palo Verde price forecast, plus a 20 percent firmness premium, and incorporates an additional wheeling adder.

Table 05-15 lists the price ranges of Palo Verde on-peak market area before any premiums or adders are included from the beginning and ending years of the planning period. They are also available in Appendix H.

Table 05-15
Seasonal Firm Market Purchase Modeling Assumptions

Scenario	AZ-PV 2026 Price (\$/MWh)	AZ-PV 2045 Price (\$/MWh)
Base Natural Gas	30.08	12.06
High Natural Gas	32.10	18.64
Low Natural Gas	22.14	8.84

5.9.6 Demand Response

Demand Response ("DR") programs for residential and smaller commercial customers are investigated through potential studies which are conducted periodically. One such study was conducted for Cheyenne Light at the request of the Wyoming OCA. The results of the CLFP study indicated that a demand response program should not be developed at this time due to the cost of the program not

⁴⁴ NERC, 2025 Summer Reliability Assessment, page 49.

⁴⁵ NERC, 2025 Long-Term Reliability Assessment, page 35.

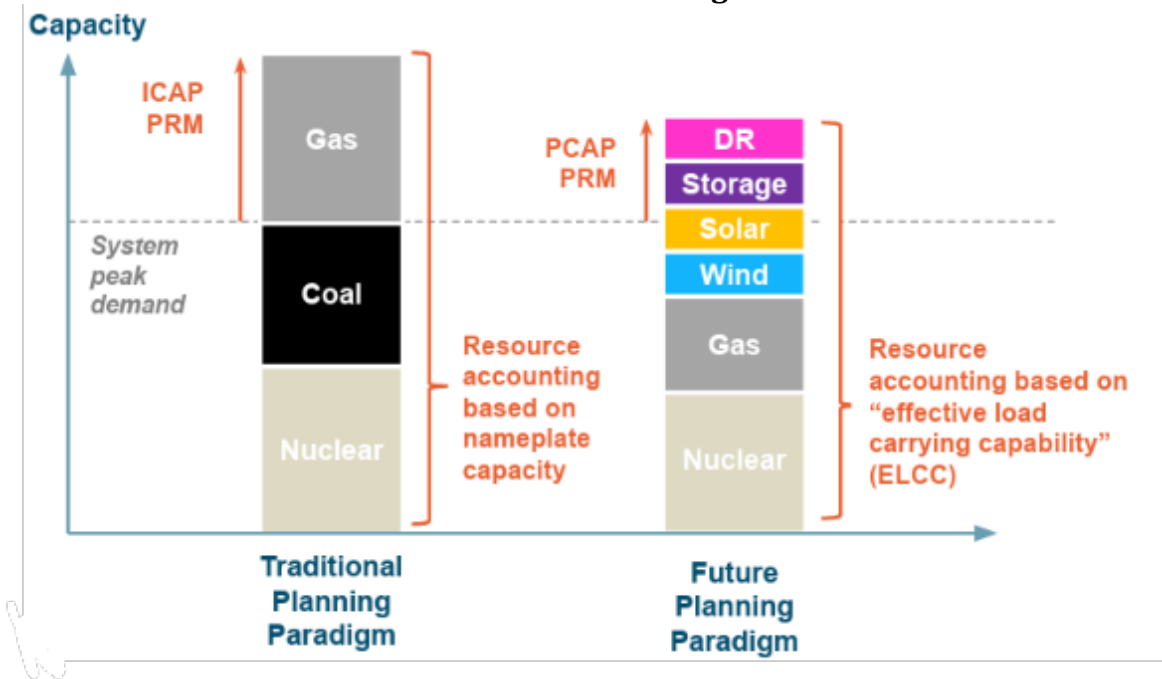
outweighing the gain in energy and demand savings. Complete study results can be found in Appendix F.

6. RELIABILITY ANALYSIS OF EVOLVING RESOURCE MIX AND CAPACITY ACCREDITATION

As reliance on renewable resources increases and overall portfolio mix changes, it is important to understand the impact this has on the system. PowerGEM conducted reliability studies to understand the impacts of increasing renewable and thermal resource contributions. This included analysis of ancillary costs, the impact on the planning reserve margin needed for the system, and load carrying capabilities of the renewable and thermal resources. The studies are contained in PowerGEM's technical report, Appendix E.

Previously, Cheyenne Light used an Installed Capacity methodology and changed to the Perfect Capacity methodology for the IRP resource adequacy analysis. The ICAP PRM represents the planning reserve margin, assuming the thermal resources are accredited at 100 percent, while solar, wind, and battery units are accredited using ELCC. This is in contrast to the PCAP PRM, where an ELCC for the thermal resources are accredited as well. Utilizing the PCAP methodology transitions the reliability uncertainty of the thermal resources (for example outages) to be accounted for in the ELCC metrics instead of the PRM value. This results in a lower PRM requirement and reduced thermal ELCC values. The ELCC values for renewables are accounted for similarly in both methodologies. Accounting for thermal and renewable ELCC values in the same manner ensures the resources are better aligned in the capacity expansion analysis. While both methodologies are an effective way to ensure reliability, both meeting the same loss of load expectations, Cheyenne Light wanted to ensure thermal resources were evaluated appropriately, especially with the expiration of both thermal and renewable PPA contracts (Wygen I coal, Happy Jack wind, and Silver Sage wind) during the NTN. Figure 06-1 illustrates the differences between the two methodologies.

Figure 06-1
ICAP and PCAP-based Accounting Framework⁴⁶



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

6.1 Resource Integration Costs

Cheyenne Light incurs integration charges for all resources on its system, including existing owned and contracted resources, since Cheyenne Light must purchase services from the new Black Hills BA. The integration charges are calculated based on Black Hills BA's Schedule 3 tariff.⁴⁷ Schedule 3 costs include regulation and frequency response charges for Variable Energy Resources ("VER") generation and Non-Variable Energy Resource ("Non-VER") generation. The charges for each tariff are projected to escalate at the 2.31 percent inflation rate over the modeling horizon. Charges for each resource type are detailed in Table 06-1.

⁴⁶ https://gridworks.org/wp-content/uploads/2025/03/2024-12-09_E3_Redacted_RA-Primer.pptx.pdf

⁴⁷ [etariff.ferc.gov/TariffBrowser.aspx?tid=2860](https://tariff.ferc.gov/TariffBrowser.aspx?tid=2860) See tariff rates in Section 3.a - BHP Transmission Service Tariff.

Table 06-1
Resource Integration Costs

Parameter	Schedule 3 (2026\$/kW-mo)
VER - Wind	\$2.9193
VER - Solar	\$5.6857
Non-VER	\$0.0361

6.2 Resource Adequacy

PowerGEM calculated the accreditable capacity of future levels of wind, solar, and storage resources utilizing an Effective Load Carrying Capability analysis to determine the percentage of the nameplate capacity that can be counted on for reserve margin planning purposes. Additionally, PowerGEM calculated the planning reserve margin target utilizing a methodology consistent with industry practice to determine the amount of capacity needed above expected peak demands to maintain reliability. This loss of load analysis uses the industry standard of one day in ten years Loss of Load Expectation, and is in-line with achieving a reliability target of 99.98%. Both types of resource adequacy studies included the assumption that Cheyenne Light was “islanded.” This means that there was not an ability to procure economy energy from neighboring utilities on short notice. The islanded assumption allows the Company to maintain its reliability with the use of its own resources, regardless of market availability.

6.3 Accreditable Capacity of Solar, Wind, and Storage

The capacity contribution of wind, solar and storage 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 expected to decline as the penetration of resources of the same type increases.

PowerGEM calculated the accreditable capacity of future levels of solar, wind, and storage resources utilizing an ELCC analysis to determine the percentage of the nameplate capacity that can be counted on for reserve margin planning purposes. For this analysis PowerGEM used the ELCC methodology that determines the quantity of “perfect” capacity that could be replaced or avoided for a non-firm resource while providing equivalent system reliability. ELCC is calculated based on a LOLE metric. LOLE is the amount of time during which system capacity is unable to meet system load. The widely accepted industry standard is a 0.1 day per year LOLE, which means the system is expected to experience firm load shed 1 day every 10 years. It also means the annual allowed downtime for the system is 2 hours and 24 minutes. This is in line with the industry standard reliability uptime target of 99.98%, which inversely relates to 1 hour and 45 minutes of allowed downtime.

Although the two metrics are not synonymous or exact, they are very close and achieve the same level of reliability in a long term planning setting.

PowerGEM starts by finding the amount of perfect capacity that needs to be added to the existing system to meet this LOLE metric. An annual 0.1 day/ year metric was used, but the amount of perfect capacity needed was calibrated for the summer (April – October) and winter (November – March) months independently. PowerGEM also analyzed the expected unserved energy, which is a reliability metric that measures the total amount of load expected to be unserved when there is a supply deficit. In doing so, they discovered that the EUE was mostly contained within the winter months due to renewable energy shortages.

They then remove the renewables from the resource portfolio and replace it with additional “perfect” capacity. The amount of perfect capacity that was added to replace the renewable resource is equal to the accredited capacity value of the renewable resource. Taking the accredited capacity divided by the nameplate value for the renewable resource results in the ELCC value. The calculated ELCC at different solar, wind, and storage penetrations on the Cheyenne Light system can be seen in Figures 06-2, 06-3, and 06-4, respectively. Additional information can be found in Appendix E.

Figure 06-2
Calculated Solar ELCC

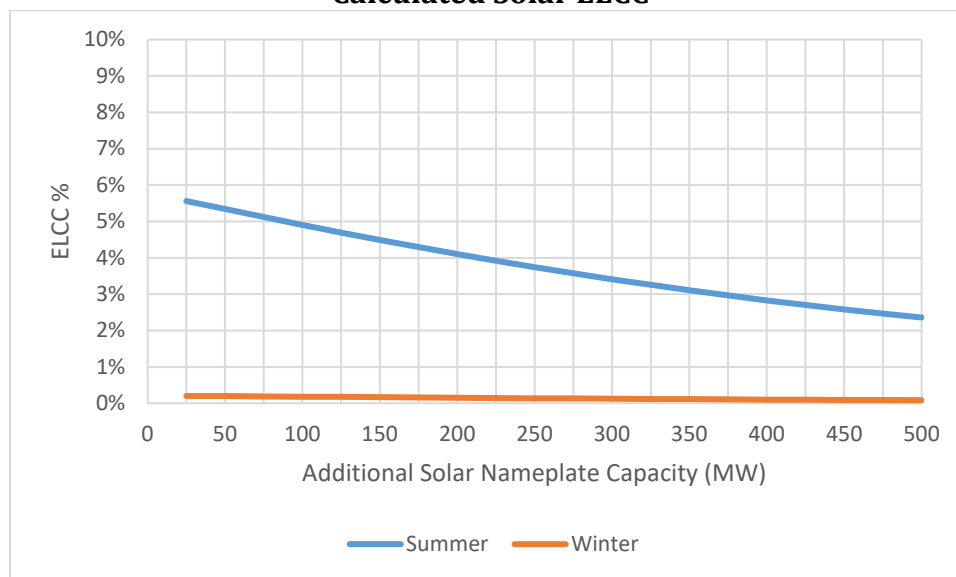


Figure 06-3
Calculated Wind ELCC

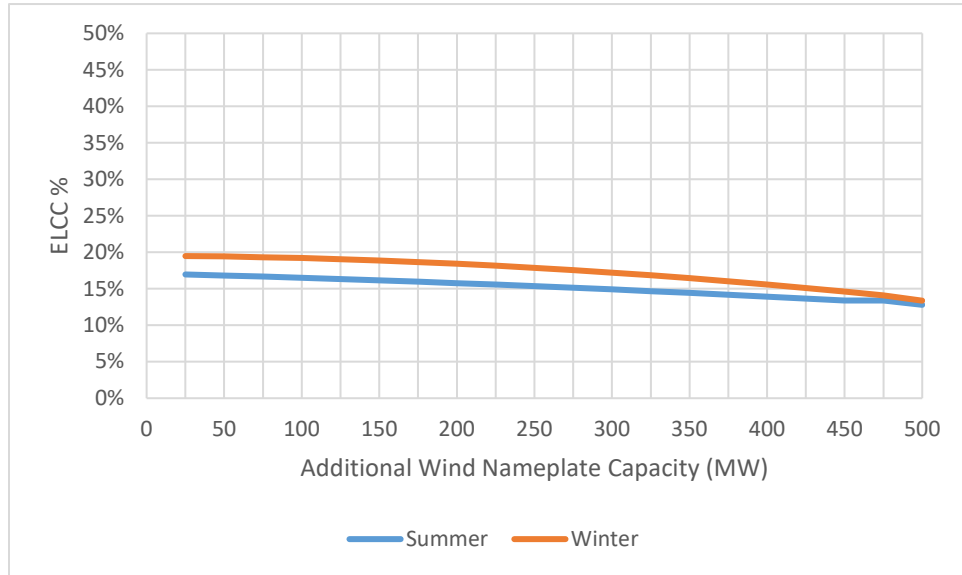
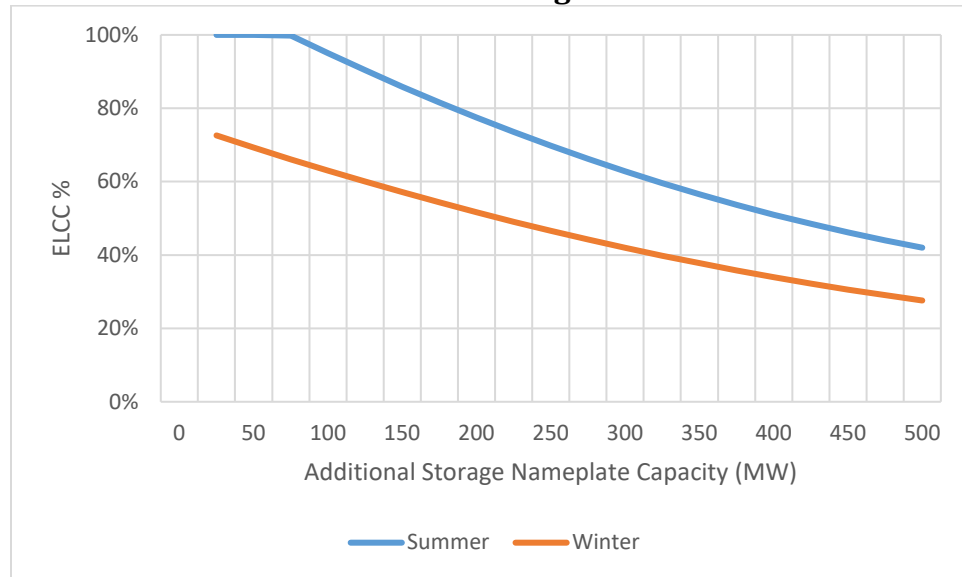


Figure 06-4
Calculated Storage ELCC



The existing wind ELCCs are higher than those for solar since there are large amounts of solar already on the system and Cheyenne Light has neared the bottom of the solar ELCC curve as it relates to Black Hills' larger footprint of the load and resource mix. As more wind integrates into the system, the benefit of similar output profiles leads to diminishing returns since the hours that incremental wind can contribute to key loss of load hours is limited. Similar to wind, as more of the same resource is added to the system, the wind and storage capacity contributions decline. Storage allows targeted capacity contributions. PowerGEM's Technical Report,

Appendix E, provides additional details around this analysis. Tables 06-2 through 06-4 show the cumulative ELCC values for incremental solar, wind, and storage additions to the Cheyenne Light system.

Table 06-2
Solar ELCCs Used in Modeling⁴⁸

Nameplate Capacity (MW)	Summer Cumulative ELCC	Winter Cumulative ELCC
25	5.6%	0.2%
50	5.3%	0.2%
75	5.1%	0.2%
100	4.9%	0.2%
125	4.7%	0.2%
150	4.5%	0.2%
175	4.3%	0.2%
200	4.1%	0.2%
225	3.9%	0.1%
250	3.7%	0.1%
275	3.6%	0.1%
300	3.4%	0.1%
325	3.3%	0.1%
350	3.1%	0.1%
375	3.0%	0.1%
400	2.8%	0.1%
425	2.7%	0.1%
450	2.6%	0.1%
475	2.5%	0.1%
500	2.4%	0.1%

⁴⁸ Seasonal ELCC values reflect the incremental capacity contribution of candidate resources added to an existing system. Results are based on smoothed, standalone ELCC curves by resource type and exclude synergistic benefits from resource mixes, which may result in differences from ELCC values shown in the consultant report provided in Appendix E.

Table 06-3
Wind ELCCs used in Modeling⁴⁹

Nameplate Capacity (MW)	Summer Cumulative ELCC	Winter Cumulative ELCC
25	17.0%	19.5%
50	16.8%	19.4%
75	16.7%	19.3%
100	16.5%	19.2%
125	16.3%	19.0%
150	16.2%	18.9%
175	16.0%	18.7%
200	15.8%	18.4%
225	15.6%	18.2%
250	15.4%	17.9%
275	15.1%	17.6%
300	14.9%	17.2%
325	14.7%	16.9%
350	14.4%	16.5%
375	14.2%	16.0%
400	13.9%	15.6%
425	13.7%	15.1%
450	13.4%	14.6%
475	13.4%	14.1%
500	12.8%	13.4%

⁴⁹ Seasonal ELCC values reflect the incremental capacity contribution of candidate resources added to an existing system. Results are based on smoothed, standalone ELCC curves by resource type and exclude synergistic benefits from resource mixes, which may result in differences from ELCC values shown in the consultant report provided in Appendix E.

Table 06-4
Storage ELCCs Used in Modeling⁵⁰

Nameplate Capacity (MW)	Summer Cumulative ELCC	Winter Cumulative ELCC
25	100.0%	72.6%
50	100.0%	69.3%
75	99.8%	66.1%
100	95.0%	63.0%
125	90.4%	60.0%
150	85.9%	57.1%
175	81.6%	54.3%
200	77.5%	51.7%
225	73.6%	49.1%
250	69.8%	46.6%
275	66.2%	44.3%
300	62.8%	42.0%
325	59.6%	39.8%
350	56.6%	37.8%
375	53.7%	35.8%
400	51.0%	34.0%
425	48.5%	32.2%
450	46.1%	30.6%
475	44.0%	29.0%
500	42.0%	27.6%

6.4 Accreditable Capacity of Thermal Resources

Traditional ICAP methodology assumes thermal resources (such as gas and coal) are subject to 100 percent ELCC, or their full installed capacities. The 2026 IRP employs the PCAP methodology, where thermal resources are subject to less than 100 percent ELCC, similar to renewable resources. This helps ensure all resources are on a level

⁵⁰ Seasonal ELCC values reflect the incremental capacity contribution of candidate resources added to an existing system. Results are based on smoothed, standalone ELCC curves by resource type and exclude synergistic benefits from resource mixes, which may result in differences from ELCC values shown in the consultant report provided in Appendix E. Additionally, an error was found after modeling efforts were completed and are believed to be negligible to the overall portfolio results. The summer BESS ELCC values should be 95% for 100 MW and less, and winter BESS ELCC values are the same as listed in the table.

playing field, not only in the resource adequacy analysis, but also in the capacity expansion modeling. This was especially important to Cheyenne Light, as several resources, including thermal resources, expire in the NTN.

The capacity contribution of conventional thermal resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand over time. Unlike renewable resources that are based on resource penetration, thermal accreditation is determined by installed capacity size and effective forced outage rates (“EFOR”). Based on the analysis PowerGEM completed for the total thermal and perfect capacity calibration, an iterative approach of determining the ELCC results for thermal resources is used. Smaller resources, 59 MW or less, are subject to an annual ELCC of 95%. Larger resources, 60 MW or more, are subject to a formulaic ELCC that is based upon their EFOR. This formula is equal to 1 minus doubling the specific unit’s EFOR ($ELCC = 1 - (2 \times EFOR)$). See Table 06-5 for an example calculation of both small and large thermal resource accreditation.

Table 06-5
Thermal ELCCs Used in Modeling

Resource	Nameplate Capacity (MW)	EFOR %	ELCC %	Accredited Capacity (MW)
Example of a small resource (<=59 MW)	20	3	95	19
Example of a large resource (>=60 MW)	80	3	94	75.2

6.5 Planning Reserve Margin

Planning reserve is the amount of capacity that each electric utility must hold in reserve above its annual peak load requirements. A planning reserve margin is a percentage applied to the expected peak load to determine the minimum additional capacity that an electric utility should plan for to ensure that it will meet its peak load obligations in the event of an unforeseen loss of generating resources, extreme weather, or other unexpected conditions. The IRP models develop an adequate resource portfolio to cover peak resource requirements plus seasonal PCAP planning reserve margins of 13 percent in the summer and 13 percent in the winter.

Planning with a 13 percent reserve margin ensures that Cheyenne Light has sufficient capacity resources to reliably meet demand while accounting for a number of unplanned possibilities (such as fluctuating load, variable levels of renewable resources, and extreme weather conditions, and unplanned outages). PowerGEM calculated a 13 percent reserve margin would be needed to meet Cheyenne Lights

system reliability standard of 1 day in 10-year Loss of Load Expectation or a 0.1 day a year outage. This LOLE is an industry standard used by resource planners, including SPP, MISO, and nearby utilities.

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

The 2021 CLFP IRP used an annual ICAP method and a resulting 15 percent PRM, which used to be the industry PRM standard. The 2024 Black Hills Power Analysis used an annual ICAP method and resulting 30 percent PRM. The current 2026 CLFP IRP uses a seasonal PCAP method and resulting 13 percent summer PRM and 13 percent winter PRM. As a reference, PowerGEM also computed seasonal ICAP values, which were not used and have not been included in any modeling for this IRP, but were used to benchmark the PCAP results. This seasonal ICAP method had a resulting 26 percent summer PRM and 30 percent winter PRM, which is in line with the previously mentioned 2024 Black Hills Power Analysis's PRM, which also encompassed Cheyenne Light and LPCS loads and resources.

The 2025 WARA PRMA⁵¹ analyzed several PRM metrics, including a Total Reliability PRM ranging from 32.5 percent in 2028 to 35.9 percent in 2034. The 2025 NERC LTRA⁵² included PRM values ranging from 30.5 percent in 2023 to 6.9 percent in 2035. Similar to Black Hills, MISO⁵³ and SPP⁵⁴ also use seasonal PRMs, due to the large difference in reliability for technology specific resources. Additionally, Black Hills continues to monitor industry compliance efforts, including energy assurance and computational load risks, while evaluating methodologies best suited to the Black Hills system. Table 06-6 provides a summary of the PRM methodologies and results for various entities demonstrating the reasonableness of Cheyenne Light's 13 percent PCAP PRM.

⁵¹ WECC, 2025 Western Assessment of Resource Adequacy PRMA, page 46

⁵² NERC, 2025 Long-Term Reliability Assessment, page 35.

⁵³ <https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2003%20PY%202025-2026%20LOLE%20Study%20Results654956.pdf>

⁵⁴

<https://www.spp.org/documents/76399/2025%20ole%20study%20prm%20recommendation.pdf>

Table 06-6
CLFP and Regional Planning Reserve Margins

CLFP 2021 IRP	CLFP 2024 Study	CLFP 2026 IRP	NERC 2025 LTRA	WARA 2025 PRMA	MISO 2024 PRM LRR	SPP 2026 PRMR
Annual	Annual	Seasonal	Annual, varying	Annual, varying	Seasonal	Seasonal
ICAP - 15%	ICAP - 30%	ICAP - 26% Summer, 30% Winter	51% 2026 > 30.5% 2030 > 6.9% 2035	Total PRM - 32.5% 2028 > 35.9% 2034	ICAP - 15.7% Summer, 38.6% Winter	17% Summer, 38% Winter in 2030
		PCAP - 13% Summer, 13% Winter		Peak PRM - 14.2% 2028 > 15.5% 2034	UCAP - 7.9% Summer, 25.3% Winter	
Based on LOLE (0.1 day/yr)	Based on LOLE (0.1 day/yr)	Based on EUE, LOLE (0.1 day/yr)	Based on EUE, LOLH, Reliability Target (0.02%)	Based on LOLE (0.1 day/yr), Reliability Target (0.02%)	Based on LOLE (0.1 day/yr Summer, 0.01 day/yr Winter)	Based on LOLE (0.05 day/yr Summer, 0.05 day/yr Winter)

As we see increases in variability across the region, it is important to have units capable of responding to unplanned possibilities. RICE units and energy storage offer efficient fast start capabilities to respond to variability in available energy. Peaking units like the RICE units can provide quick response capabilities in the event of an unplanned outage. Since they are capable of ramping up quickly, they can minimize some of the problems caused by outages and variability. These units operate very efficiently in short frequencies, which keeps costs to customers low when needing to quickly respond to changes in generation. Additionally, their small generator size (18 MW each for standard RICE) provides a way to help mitigate large contingency resources when planning for reserve margins. Similarly, energy storage technologies can dispatch rapidly to mitigate short duration impacts, or to provide a bridge resource until another resource solution can occur.

Spinning and non-spinning contingency reserves have historically been provided to Black Hills Energy through its participation in the Western Power Pool (“WPP”) as a sub-entity of WAPA, where Cheyenne Light could each rely on the WPP for approximately 60 minutes after a forced outage, but then must replace the lost capacity.⁵⁵ As of April 1, 2026, Cheyenne Light continues to receive this service through the WPP as a sub-entity of the Black Hills BA.

⁵⁵ <https://www.westernpowerpool.org/resources/reserve-sharing-program-documentation>

Cheyenne Light has a Reserve Sharing Agreement with Black Hills BA. By this agreement, CLFP must hold resources that can respond in less than 10 minutes equal to the sum of 3 percent of load and 3 percent of online generation. In turn, the agreement gives CLFP the ability to call on reserve energy for up to 60 minutes after a qualifying event.

Black Hills BA has adopted the WPP Reserve Sharing Group requirements which align with WECC's Standard BAL-002-WECC-3 for Contingency Reserves, the WPP monitors reserve sharing response performance to ensure the group as a whole meets these criteria.⁵⁶ 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.

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

7. TRANSMISSION SYSTEM

Transmitting power relies on two main types of structures: transmission and distribution structures, along with transmission to distribution step down substations. Transmission structures efficiently carry high voltage electricity over long distances to distribution substations. Distribution 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 and distribution functions of Cheyenne Light are centrally managed. CLFP plans and manages the infrastructure to ensure their continued reliability to safely deliver power to customers. The transmission group also administers the interconnection and open access of this system with other regional systems.

7.1 The Transmission and Distribution System

Cheyenne Light invests in transmission and distribution maintenance, upgrades, and new construction to meet the needs of customers and maintain reliability throughout their systems. Cheyenne Light owns 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

⁵⁶ See Appendix B for the entire WECC standard.

Light invests in the accessibility, capacity, and integrity of its systems to meet customer growth.

Table 07-1 details the miles of transmission and distribution lines owned by Cheyenne Light as posted in the 2025 Black Hills Corporation Annual Report.

Table 07-1
Miles of Transmission and Distribution Line

Utility	State	Transmission (miles)	Distribution (miles)
Cheyenne Light	Wyoming	366	1,373

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

7.2 Cheyenne Light Transmission System

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.

Prior to January 31, 2026, Cheyenne Light was a network customer of the WAPA Loveland Area Project (“WAPA-LAP”) transmission system. Cheyenne Light depended 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. In December 2025, Cheyenne Light completed the Ready Wyoming Project removing the need to purchase network transmission service from WAPA-LAP. The project includes one new substation, two replacement substations, four expanded substations, three new 230 kV transmission lines, two new 115 kV transmission lines, and associated distribution facilities. These new facilities allow Cheyenne Light to deliver energy from its owned and contracted generating resources without purchasing network transmission service from WAPA-LAP.

7.3 Regulatory Requirements

7.3.1 Federal

Cheyenne Light is 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 maintains 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, recordkeeping, and reporting.

With FERC authorization, Cheyenne Light sells electric capacity and energy at market-based rates under filed tariffs and submit quarterly reports related to the transactions. Cheyenne Light owns and operates FERC-jurisdictional interstate transmission facilities and provides open access transmission service under filed tariffs. FERC conducts routine audits regarding compliance with regulations.

Cheyenne Light also complies with NERC reliability standards.

7.3.2 State

Cheyenne Light follows 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.

7.4 Transmission Planning

Cheyenne Light conducts comprehensive internal and regional transmission planning that is carefully coordinated with all local and regional transmission planners as required by FERC Order No. 890 and FERC Order No. 1000.⁵⁷

7.4.1 Local Transmission Planning

Cheyenne Light's local transmission planning process is defined in Attachment K of the OATT. The goal of the local transmission planning process is to design a reliable, least cost transmission system that will perform under expected system conditions wherein customer load can be served reliably throughout the planning horizon

The utility recognizes the importance of stakeholder input to transmission planning. A stakeholder may include, but is not limited to, network and point-to-point transmission customers, sponsors of transmission solutions, generating solutions

⁵⁷ The transmission plans consider the entire region in which the utilities operate and the value of market access discussed in Section 2: Planning Environment.

and solutions utilizing demand response resources, interconnected neighbors, regulatory and state bodies and other parties.

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.”⁵⁸ 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 notifies stakeholders at the start of a study and invites 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”).

7.4.2 Transfer Capability

Cheyenne Light uses the Rated System Path Methodology as described in NAESB Business Practice Standard WEQ-023-2.2 for determining Total Transfer Capability (“TTC”) and Available Transfer Capability (“ATC”). Cheyenne Light’s WEQ-023 ATC ID methodology⁵⁹ is publicly available on OASIS. Based on this methodology, the TTC posted for existing paths is expected to be sufficient to support the loads and resources associated with this IRP.

⁵⁸ NERC Standard TPL-001-5.1 — Transmission System Planning Performance Requirements.

⁵⁹ https://www.oasis.oati.com/woa/docs/CLPT/CLPTdocs/OASIS-003.1_ATC_ID.pdf

7.4.3 Regional Transmission Planning

Through WECC and WestConnect, Cheyenne Light participates 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”), 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.

7.4.4 Transmission Line Siting Process

Cheyenne Light generally adheres 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 often works 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 works directly with landowners to obtain rights-of-way on private lands and to minimize the impact building has on surrounding properties.

7.5 Wildfire Risk and Mitigation

Cheyenne Light has safely and reliably served customers for many years. Throughout this time, our teams have managed the wildfire risk associated with operating an electric utility. Black Hills Energy's Wildfire Mitigation Plan ("WMP")⁶⁰ is designed to promote public safety and mitigate the risk of utility infrastructure caused wildfires, and to mitigate the potential severity of any wildfire that does occur. The programs and initiatives described in the WMP are designed to reduce wildfire ignition potential associated with our electric facilities. To support the integrity of our energy delivery systems, we design, construct, maintain and operate our electric infrastructure in a manner that reduces the risk of wildfire ignition. By incorporating industry practices into our standards, operating procedures and education, we are committed to a fire safe culture across our company and in our communities.

Our wildfire risk mitigation strategies are supported by a three-layered approach, driven by asset-based risk assessments, that are incorporated into our Asset Programs, Integrity Programs, and Operational Response.⁶¹

Asset Programs represent the first layer of our wildfire risk mitigation strategy. Our teams perform and/or oversee a wide variety of inspections and maintenance activities across our electric transmission and distribution system. Asset Programs include: Vegetation Management; Line Patrol; and, Pole Inspections.

The second layer of our wildfire risk mitigation strategy is Integrity Programs. Integrity Programs are a proactive approach to system improvements and modernization through capital investments, and includes wildlife retrofits and undergrounding projects.

The third layer of our wildfire risk mitigation strategy is Operational Response, which uses situational awareness tools to make risk-driven decisions during specific weather conditions, including: system reconfigurations, adjusted daily work

⁶⁰ <https://www.blackhillsenergy.com/safety/wildfire-safety-and-prevention>

⁶¹ Cheyenne Light's Wildfire Mitigation Plan was filed with the Commission in Docket No. 20003-262-EA-25 (Record No. 18007).

activities, equipment operation (non-reclosing energized power lines) and potential Emergency Public Safety Power Shutoffs.

7.6 Capital Investments

7.6.1 Planning and Implementation

Cheyenne Light follows 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. An internal team including the sponsor, transmission and distribution planning, engineering, and project delivery establish a preliminary scope, project duration, and cost. Using the Capital Scoring Ranking system, this project origination team 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, the project origination team reviews the scope, schedule, and cost of every existing and new project and ranks them in priority for completion in a five-year plan. The team 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.

7.6.2 Transmission and Distribution Projects

Cheyenne Light routinely evaluates the condition of their transmission and distribution systems and determines if expansion, upgrades or rebuilds are needed to ensure continued reliability.

To manage this process for their distribution systems, Cheyenne Light developed the Distribution System Integrity Program (“DSIP”). This program enables each utility to programmatically and systemically replace or rebuild aging distribution assets before they fail or present a risk to customers.

In addition, the utility evaluates its transmission systems annually to determine if any transmission facilities need to be expanded, upgraded, rebuilt, or replaced. The utility creates a budget and a timeline for these changes based on their risk to reliability or safety.

7.6.2.1 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 increasing customer load.

115 kV Ready Wyoming Expansion. This expansion included seven projects:

- Build the new 115 kV and 13.2 kV Allison Draw substation.
- Build the new 115 kV and 13.2 kV Orchard Valley substation
- Add Allison Draw – Campstool 115 kV transmission line.
- Add Allison Draw – CPGS 115 kV transmission line.
- Add Bison – Orchard Valley 115 kV transmission line.
- Add Orchard Valley – King Ranch 115 kV transmission line.
- Add Bison – West Cheyenne 115 kV transmission line.

This project was completed in 2025.

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

- Build the new 115 kV and 24.9 kV Wallick substation.
- Add two transmission lines, each approximately 1.5 miles long.

The substation was completed in 2025.

230 kV Ready Wyoming Expansion. This expansion includes six projects:

- Build the new 230 kV Sweetgrass substation.
- Build the new 230 kV West Cheyenne substation.
- Build the new 230 kV Bluffs substation.
- Add West Cheyenne – Sweetgrass 230 kV transmission line
- Add West Cheyenne – Windstar 230 kV transmission line
- Add Sweetgrass – Bluffs 230 kV transmission line

This project was completed in 2025.

115 kV Happy Jack – North Range #2. This project will add a second Happy Jack – North Range 115 kV line to support anticipated load growth and improve reliability. This project is planned to be completed in 2026.

115 kV Sweetgrass - Bison #3 & #4. This project will add the third and fourth Sweetgrass– Bison 115 kV lines to support load growth and reliability.

This project is planned to be completed in 2027.

230 kV Robinson Substation. This project will add a new 230 kV substation cutting into the existing West Cheyenne – Sweetgrass 230 kV line to support load growth.

This project is planned to be completed in 2027.

230 kV Holliday Substation. This project will add a new 230 kV substation cutting into the existing Sweetgrass – Bluffs 230 kV line to interconnect a 365 MW solar and BESS generator interconnection project.

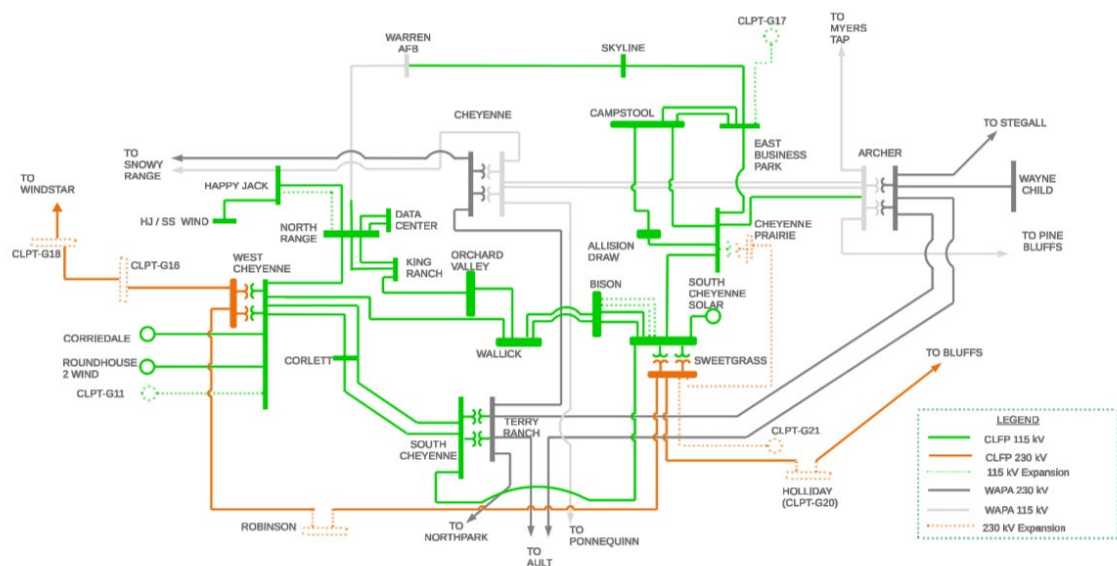
This project is planned to be completed in 2027.

230 kV CLPT-G11 Terminal Addition. This project will expand the existing West Cheyenne 115 kV substation to interconnect a 150 MW wind generator interconnection project.

This project is planned to be completed in 2028.

Figure 07-1 depicts a diagram of the planned projects.

Figure 07-1
Cheyenne Light Transmission Project Diagram



8. PORTFOLIO ANALYSIS AND SELECTION

In this Section, the Company provides information regarding its assessment of need for additional resources. Energy and demand forecasts are compared against the existing level of resources and planning reserve margin to assess the utility's need to acquire additional resources.

8.1 Future Resource Analysis and Selection

The Cheyenne Light preferred plan consists of adding gas and battery storage resources in the near-term need planning period through the analysis described in the following section.

8.2 Load and Resource Balance

A load and resource balance was prepared for Cheyenne Light to compare their annual peak demand with the accredited capacity contribution of existing resources. The load and resource balance highlights the years in which forecasted demand exceeds resources, indicating a need for additional capacity. The load and resource balance considered the 13 percent seasonal planning reserve margin requirement.

The load and resource balance for Cheyenne Light shows a capacity deficit during the near-term need planning period. The capacity deficit must be met by adding physical resources.⁶²

8.2.1 Cheyenne Light Base 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.

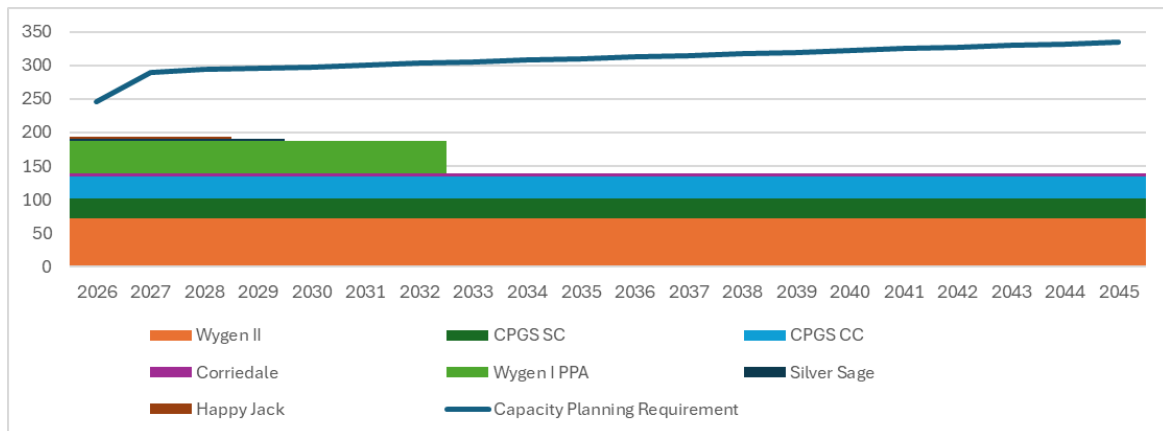
⁶² Appendix J - Load and Resource Balances 2026–2045 contains the load and resource balance amount for Cheyenne Light for the entire planning period.

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

Cheyenne Light Load and Resource Balance								
Resource (MW)	2026	2027	2028	2029	2030	2031	2032	2033
Peak Demand	217	256	261	262	264	266	268	270
Planning Reserve (13%)	28	33	34	34	34	35	35	35
Peak Plus Reserve	245	289	295	296	298	300	303	305
Wygen II	72	72	72	72	72	72	72	72
CPGS SC	30	30	30	30	30	30	30	30
CPGS CC	32	32	32	32	32	32	32	32
Wygen I PPA	48	48	48	48	48	48	48	
Happy Jack PPA	4	4	4					
Silver Sage PPA	3	3	3	3				
Corriedale	6	6	6	6	6	6	6	6
Total Capacity	194	194	194	190	187	187	187	139
Peak Plus Reserves	245	289	295	296	298	300	303	305
Capacity Excess/ Deficit MW	-51	-95	-101	-106	-111	-113	-116	-166
Capacity Excess/ Deficit %	-21%	-33%	-34%	-36%	-37%	-38%	-38%	-54%

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 13 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 Reserve Margin (2026–2045)



8.2.2 Cheyenne Light and LPCS Load and Resource Balance

Table 08-2 contains the LPCS and other base retail customer load and resource balance requirements for the near-term need planning period, including the base load forecast and existing resources.

Table 08-2
Cheyenne Light and LPCS Load and Resource Balance

Cheyenne Light and LPCS Load and Resource Balance								
Resource (MW)	2026	2027	2028	2029	2030	2031	2032	2033
CLFP Peak Demand	217	256	261	262	264	266	268	270
LPCS Peak Demand	200	450	550	600	600	650	650	650
Planning Reserve (13%)	54	92	105	112	112	119	119	120
Peak Plus Reserve	471	797	916	974	976	1035	1037	1040
Wygen II	72	72	72	72	72	72	72	72
CPGS SC	30	30	30	30	30	30	30	30
CPGS CC	32	32	32	32	32	32	32	32
Wygen I PPA	48	48	48	48	48	48	48	
Happy Jack PPA	4	4	4					
Silver Sage PPA	3	3	3	3				
Corriedale	6	6	6	6	6	6	6	6
Roundhouse II Wind	30	30	30	30	30	30	30	30
South Cheyenne Solar	13	13	13	13	13	13	13	13
Cowboy II Solar		33	33	33	33	32	32	32
Cowboy II BESS		130	130	130	130	130	130	130
Customer BTM Generation	150	150	150	150	150	150	150	150
Total Capacity	387	550	550	546	543	542	542	494
Peak Plus Reserves	471	797	916	974	976	1035	1037	1040
Capacity Excess/ Deficit MW	-84	-248	-367	-428	-433	-493	-495	-546
Capacity Excess/ Deficit %	-18%	-31%	-40%	-44%	-44%	-48%	-48%	-53%

8.3 Integrated Resource Planning Process

1898 and Co. was retained to provide analytical services in support of the IRP. 1898 used EnCompass to perform integrated resource planning analysis including capacity expansion and production cost modeling.⁶³

⁶³ See Confidential Appendix I - 1898 IRP Modeling Report.

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 sensitivities and their associated risk factors.

8.3.1 Near-Term Need Planning Period

The IRP employs an eight-year near-term need planning period that addresses the years 2026–2033. This time period includes the years the IRP identified Cheyenne Light’s need for additional resources. The near-term need period provides adequate time for acquiring the necessary resources to meet customer electricity needs. Additionally, the eight-year period includes the expiration of the Wygen I PPA (December 31, 2032) to ensure that any identification of additional resources takes this expiration into consideration in the selection of the preferred portfolio. This near-term period is outside of the Near-Term Need as identified by the PSC IRP Rules in Chapter 7, Section 3(h) which states it is “a subset of the Action Plan items determined necessary for the Affected Electric Utility to meet its short-term, i.e., zero to six years, load forecast.”

8.3.2 Long-Term Planning Period

The IRP is based on a long-term planning period of 2026 through 2045. Cheyenne Light selected this planning period because it is sufficiently long to incorporate the operating life expectancies of both thermal and renewable resources.

8.3.3 Capacity Expansion Modeling

Yes Energy’s EnCompass 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 (“PVR”) subject to meeting load plus reserves.

8.3.4 Production Cost and Financial Modeling

Yes Energy's EnCompass production cost model 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.

8.4 Base Plan (Reference Case) Analysis

The IRP first examined a base plan, or reference case, 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 PVR. The IRP refers to this as the Base Plan.

The Capacity Expansion model developed the CLFP Base Plan for Cheyenne Light 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 or environmental regulation applied during the planning period.
- Base peak demand and annual energy forecasts, including 50 MW of ITS load.⁶⁴
- Base natural gas, coal, and economy energy price forecasts.⁶⁵
- Seasonal firm market purchases up to 15% of total load through NTN.
- Conventional and renewable energy resource options.⁶⁶

8.5 Scenario and Sensitivity Analysis

Scenario and sensitivity analyses were conducted during which the Capacity Expansion model analyzed ten scenarios and three sensitivities to derive candidate resource portfolios. The scenarios and sensitivities include variables that would create the largest impact on cost variability and risk to result in unique resource portfolios. The resultant candidate resource portfolios developed for Cheyenne Light

⁶⁴ Described in Section 4: Load Forecast.

⁶⁵ Described in Section 3: Modeling Inputs and Assumptions.

⁶⁶ Described in Section 5: Supply-Side Resources.

are provided below. A brief description of the variables for the set of standard scenarios and their corresponding variations is listed as follows.⁶⁷

1. CLFP Base (Reference) Plan

- Assumed variables as described in “Base Plan Analysis” in Section 8.4.
- Developed candidate resource portfolio: CLFP Base Plan.

2. 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 portfolio: Low Gas.

3. 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 portfolio: High Gas.

4. 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 inclusive of a 20 MW step load decrease beginning in 2027.
- Assumed all other modeling variables as described in “Base Plan Analysis.”
- Developed candidate resource portfolio: Low Load.

5. 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 inclusive of a 50 MW step load increase beginning in 2027.

⁶⁷ Fuel and energy prices forecasts as well as load forecasts used in all scenarios and sensitivities are described in Section 3: Modeling Inputs and Assumptions and Section 4: Load Forecast.

- Assumed all other modeling variables as described in “Base Plan Analysis.”
- Developed candidate resource portfolio: High Load.

The five above scenarios were analyzed through capacity expansion using the associated assumptions to produce unique portfolios. During production cost modeling, the unique portfolios identified in capacity expansion were used and analyzed under base plan assumptions. This ensures each of the resulting PVRs are compared neutrally under most probable future assumptions. It also ensures the risk analysis is conducted equally among all portfolios.

Table 08-3 summarizes the assumption variables used for each of these scenarios.

Table 08-3
Scenarios 1-5 Characteristics Summary

Scenario	Base	Low Gas	High Gas	Low Load	High Load
Load Growth	Median	Median	Median	Low + Step	High + Step
Electric Price	Median	Low	High	Median	Median
Gas Price	Median	Low	High	Median	Median
Resource Selection	Economic	Economic	Economic	Economic	Economic

Similar to the above scenarios, three environmental scenarios were analyzed through capacity expansion and production cost modeling to produce unique, counterfactual portfolios. Their corresponding variations are listed as follows.⁶⁸

6. House Bill 200: Amine CCS Technology Counterfactual Scenario

- Investigated the impact that House Bill 200 would have on the resource portfolio.
- Forced addition of amine carbon capture technology to Wygen II in 2030.
- Assumed all other all other modeling variables as described in “Base Plan Analysis.”
- Developed candidate resource portfolio: Amine CCS.

⁶⁸ Capacity expansion models will economically choose Wygen II conversion to gas over carbon capture technology addition. Carbon capture was forced as a selection in the model to fully address the cost considerations of House Bill 200 under various carbon capture technologies.

7. House Bill 200: Carbon Geocapture (Conservative) CCS Technology Counterfactual Scenario

- Investigated the impact that House Bill 200 would have on the resource portfolio.
- Forced addition of geocapture (conservative) carbon capture technology to Wygen II in 2030.
- Assumed all other all other modeling variables as described in “Base Plan Analysis.”
- Developed candidate resource portfolio: Carbon Geocapture (Conservative) CCS.

8. House Bill 200: Carbon Geocapture (Low End) CCS Technology Counterfactual Scenario

- Investigated the impact that House Bill 200 would have on the resource portfolio.
- Forced addition of geocapture (low end) carbon capture technology to Wygen II in 2030.
- Assumed all other all other modeling variables as described in “Base Plan Analysis.”
- Developed candidate resource portfolio: Carbon Geocapture (Low End) CCS.

Table 08-4 summarizes the assumption variables used for each of these scenarios.

Table 08-4
Scenarios 6-8 Characteristics Summary

Scenario	Amine CCS	Carbon Geocapture (Conservative) CCS	Carbon Geocapture (Low End) CCS
Load Growth	Median	Median	Median
Electric Price	Median	Median	Median
Gas Price	Median	Median	Median
Resource Selection	Economic + Amine Carbon Capture	Economic + Conservative Geocapture Carbon Capture	Economic + Low End Geocapture Carbon Capture

The next set of scenarios explain how CLFP and LPCS loads and resources have the potential to be optimized jointly. Similar to the above scenarios, these scenarios were analyzed through capacity expansion and production cost modeling to produce unique portfolios. This ensures each of the resulting scenario PVRs are compared neutrally. A brief description of the variables and their corresponding variations are listed as follows.⁶⁹

9. LPCS Base Standalone Scenario

- Includes no Cheyenne Light load and resources.
- Analyzed only LPCS load and resources.
- Optimized renewable energy resources to match portions of LPCS energy need.
- Assumed all other modeling variables as described in “Base Plan Analysis.”
- Developed candidate resource portfolio: LPCS Base Standalone.

10. CLFP and LPCS Base Energy Scenario

- Combined the load and resources from the LPCS Base Standalone Scenario with the CLFP Base Plan.⁷⁰
- Optimized renewable energy resources to match the portions of LPCS energy need.
- Assumed all other modeling variables as described in “Base Plan Analysis.”
- Joint CLFP and LPCS optimization was conducted to consider energy sharing only.
- Developed candidate resource portfolio: CLFP + LPCS Base Energy.

Table 08-5 summarizes the assumption variables used for each of these scenarios.

⁶⁹ Fuel and energy prices forecasts as well as load forecasts used in all scenarios and sensitivities are described in Section 3: Modeling Inputs and Assumptions and Section 4: Load Forecast.

⁷⁰ CLFP and LPCS load forecasts and resource options are described in Section 4: Load Forecast and Section 5: Supply Side Resources.

Table 08-5
Scenarios 9-10 Characteristics Summary

Scenario	LPCS Base Standalone	CLFP + LPCS Base Energy
Load Growth	LPCS	Median + LPCS
Electric Price	Median	Median
Gas Price	Median	Median
Resource Selection	Economic + Optimized Renewables	Economic + Optimized Renewables

Capacity expansion and production cost modeling analysis was also performed for three alternative sensitivities with increased ITS load. These sensitivities are intended to identify potential resource builds under conditions of higher-than-expected large load as some forecasted LPCS load may instead be requested by the LPCS customer to be served as ITS load pursuant to the LPCS rate schedule – which requires a minimum amount of load to be placed on ITS, but does not specify a maximum amount of ITS service that can be requested by the LPCS customer. A brief description of the variables and their corresponding variations are listed as follows.⁷¹

11. Alternative CLFP Standalone Sensitivity

- All parameters are the same as CLFP’s Base Plan Scenario, except for load adjustment to the ITS forecast.
- Increased total ITS load from 50 MW to 75 MW, using the Alternative CLFP load.⁷²
- Assumed all other modeling variables as described in “Base Plan Analysis.”
- Developed candidate resource portfolio: Alternative CLFP Standalone.

12. Alternative LPCS Standalone Sensitivity

- All parameters are the same as LPCS Base Standalone Scenario, except for load adjustment from the ITS forecast.
- Analyzed only LPCS load and resources with alternative 75 MW ITS load.
- Assumed all other modeling variables as described in “Base Plan Analysis.”
- Developed candidate resource portfolio: Alternative LPCS Standalone.

⁷¹ Fuel and energy prices forecasts as well as load forecasts used in all scenarios and sensitivities are described in Section 3: Modeling Inputs and Assumptions and Section 4: Load Forecast.

⁷² Alternative load forecasts are described in Section 4: Load Forecast.

13. Alternative CLFP and LPCS Energy Sensitivity

- Combined the load and resources from the Alternative CLFP Standalone Sensitivity with Alternative LPCS Standalone Sensitivity.
- Assumed all other modeling variables as described in “Base Plan Analysis.”
- Joint CLFP and LPCS optimization was conducted to consider energy sharing only.
- Developed candidate resource portfolio: Alternative CLFP + LPCS Energy.

Table 08-6 summarizes the assumption variables used for each of these scenarios.

Table 08-6
Sensitivities 11-13 Characteristics Summary

Sensitivity	Alternative CLFP Standalone	Alternative LPCS Standalone	Alternative CLFP + LPCS Energy
Load Growth	Median	LPCS	Median + LPCS
Electric Price	Median	Median	Median
Gas Price	Median	Median	Median
Resource Selection	Economic	Economic + Optimized Renewables	Economic + Optimized Renewables

8.5.1 Discussion of Scenarios and Sensitivities

Scenarios 2 through 5 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 because of these future uncertainties.⁷³

Scenarios 6, 7, and 8 change the base assumptions of how Wygen II operates, evaluating for different carbon capture technologies. These scenarios added carbon capture to Wygen II to comply with Wyoming House Bill 200. This shows the PVR

⁷³ The forecasted electric market prices and natural gas prices used to model the scenarios and sensitivities are detailed in schedules in Appendix H – CLFP Price and Cost Forecasts.

impacts of the costs that would be incurred as a result of installing and operating carbon capture equipment to comply with HB200.⁷⁴

Scenario 10 changes the base load and resource assumptions by including the LPCS load and resources with the CLFP base system assumptions. Additional renewable and behind-the-meter generation were added to LPCS' supply side resources to simulate LPCS' actual generation. Both systems were optimized together to share energy from existing and candidate resources when making future portfolio selections.

Portfolio 9 is similar to Portfolio 10, except it removes the CLFP load and resources, and only examines the LPCS load and resources as a standalone system. The CLFP and LPCS Base Energy and LPCS Base Standalone scenarios were meant to be directional and give Cheyenne Light a better understanding of how to most efficiently serve these customers. Specific LPCS resources will continue to be evaluated with these customers prior to final selection.

Portfolios 11 through 13 were run as alternative sensitivities. These were run with changes to the base assumptions, namely to allow for the potential that some forecasted LPCS load may instead be requested by the LPCS customer to be served as ITS load pursuant to the LPCS rate schedule – which requires a minimum amount of load to be placed on ITS, but does not specify a maximum amount of ITS service that can be requested by the LPCS customer. The resulting increase in ITS load under this alternative sensitivity is offset by an equal reduction to the LPCS load. Portfolio 11 applies the alternative Cheyenne Light load with ITS load increased from 50 MW to 75 MW. Portfolio 12 incorporates an alternative LPCS load driven by a decrease in LPCS load that was shifted to ITS load. Portfolio 13 combines both alternative CLFP and alternative LPCS loads into a jointly optimized system. This alternative joint system is optimized for energy, while each independent system maintains its capacity requirements.

8.5.2 Cheyenne Light Resource Portfolios

In general, all thirteen resource portfolios selected new natural gas fired units, as well as energy storage in the near-term need planning period (with the exception of the Low Load and portions of the joint scenarios). In the first eight resource portfolios, which include the five standard scenarios and three environmental scenarios, at least 36 MW of new natural gas fired units and 50 MW of energy storage were identified during the near-term need planning period (again, with the exception of the Low Load scenario, which did not select a gas resource in the NTN). Additional natural gas fired RICE units were built within the planning horizon for each of these portfolios as well.

⁷⁴ Wyo. Stat. §37-18-101-102, Commission Rules, Section 38

Table 08-7 contains the Capacity Expansion modeling results for the standard Cheyenne Light scenarios.

Table 08-7
Cheyenne Light Standard Resource Portfolios—Scenario Analysis

Cheyenne Light Resource Portfolios – Scenario Analysis (MW)					
Year	Base Plan	Low Gas	High Gas	Low Load	High Load
2026					
2027					
2028					
2029	36 MW RICE 50 MW BESS	36 MW RICE 50 MW BESS	36 MW RICE 50 MW BESS	50 MW BESS	107 MW RICE 50 MW BESS
2030					
2031					
2032					
2033	36 MW RICE -60 MW Wygen I	36 MW RICE -60 MW Wygen I	36 MW RICE -60 MW Wygen I	36 MW RICE -60 MW Wygen I	71 MW RICE -60 MW Wygen I
2034	71 MW RICE	71 MW RICE	36 MW RICE 100 MW Wind	36 MW RICE 50 MW Wind	36 MW RICE
2035					
2036			50 MW Wind		36 MW RICE
2037					
2038					
2039					
2040	-90 MW Wygen II 90 MW Wygen II NG	-90 MW Wygen II 90 MW Wygen II NG	-90 MW Wygen II 90 MW Wygen II NG	-90 MW Wygen II 90 MW Wygen II NG	-90 MW Wygen II 90 MW Wygen II NG
2041			50 MW Wind		
2042					
2043					
2044					
2045					50 MW Wind

The Cheyenne Light resource portfolios rely on seasonal firm market purchases through 2033. Table 08-8 contains the amount of seasonal firm market purchases included in each Cheyenne Light scenario listed in the table above.

Table 08-8
Cheyenne Light Standard Resource Portfolios—Seasonal Firm Market Purchases

Seasonal Firm Market Purchases (MW)					
Year	Base	Low Gas	High Gas	Low Load	High Load
2026	25	50	25	25	50
2027	50	50	50	25	50
2028	50	50	50	50	50
2029	50	50	50	50	50
2030	50	50	50	50	50
2031	50	50	50	50	50
2032	50	50	50	50	50
2033	50	50	50	50	50

Table 08-9 contains the Capacity Expansion modeling results for the environmental Cheyenne Light scenarios.

Table 08-9
Cheyenne Light Environmental Resource Portfolios—Scenario Analysis

Cheyenne Light Environmental Resource Portfolios – Scenario Analysis (MW)			
Year	Amine CCS	Carbon GeoCapture (Conservative) CCS	Carbon GeoCapture (Low End) CCS
2026			
2027			
2028			
2029	36 MW RICE 50 MW BESS	36 MW RICE 50 MW BESS	36 MW RICE 50 MW BESS
2030	-90 MW Wygen II 56 MW Wygen II Amine	-90 MW Wygen II 58 MW Wygen II Mem Con	-90 MW Wygen II 58 MW Wygen II Mem Low
2031			
2032			
2033	71 MW RICE -60 MW Wygen I	71 MW RICE -60 MW Wygen I	71 MW RICE -60 MW Wygen I
2034	36 MW RICE	36 MW RICE	36 MW RICE
2035			
2036	36 MW RICE	36 MW RICE	36 MW RICE
2037			
2038			
2039			
2040			
2041			
2042			
2043			
2044			
2045			

Table 08-10 contains the amount of seasonal firm market purchases included in each Cheyenne Light scenario listed in the table above.

Table 08-10
Cheyenne Light Resource Portfolios—Seasonal Firm Market Purchases

Seasonal Firm Market Purchases (MW)			
Year	Amine CCS	Carbon Geocapture (Conservative) CCS	Carbon Geocapture (Low End) CCS
2026	25	25	25
2027	50	50	50
2028	50	50	50
2029	50	50	50
2030	50	50	50
2031	50	50	50
2032	50	50	50
2033	50	50	50

8.5.3 LPCS Standalone and Joint CLFP & LPCS Resource Portfolios

The LPCS Standalone and joint CLFP Base and LPCS resource portfolios were created by running scenarios 9-10. For the combined CLFP and LPCS resource portfolio, similar resources were selected. In 2029, in the CLFP and LPCS Base Energy portfolio, 36 MW of RICE and 50 MW of BESS were selected in the CLFP portion, and 649 MW CCCT and 600 MW of wind were selected in the LPCS portion.

Table 08-11 contains the Capacity Expansion modeling results for the LPCS Standalone and joint Cheyenne Light Base and LPCS scenarios.

Table 08-11
Joint CLFP Base & LPCS Plan Resource Portfolios—Scenario Analysis

CLFP + LPCS Resource Portfolios – Scenario Analysis (MW)			
Year	LPCS Standalone	CLFP + LPCS Base Energy	
		CLFP	LPCS
2026			
2027			
2028			
2029	214 MW RICE 200 MW BESS 600 MW Wind	36 MW RICE 50 MW BESS	649 MW CCCT 600 MW Wind
2030	71 MW RICE		
2031			100 MW Wind
2032			
2033	50 MW BESS	36 MW RICE -60 MW Wygen I	
2034	143 MW RICE 100 MW Wind	71 MW RICE	
2035			
2036			
2037			
2038			
2039			
2040		-90 MW Wygen II 90 MW Wygen II NG	
2041			
2042			
2043			
2044	36 MW RICE 200 MW Wind		200 MW Wind
2045			

Table 08-12 contains the amount of seasonal firm market purchases included in each joint scenario corresponding to the table above.

Table 08-12
Joint CLFP Base & LPCS Plan Resource Portfolios—Seasonal Firm Market Purchases

CLFP + LPCS Resource Portfolios – Seasonal Firm Market Purchases (MW)			
Year	LPCS Standalone	CLFP + LPCS Base Energy	
		CLFP	LPCS
2026	0	25	0
2027	0	50	0
2028	0	50	0
2029	0	50	0
2030	0	50	0
2031	0	50	0
2032	0	50	0
2033	0	50	0

In the joint scenarios, energy sharing was allowed from the resources of each system to illustrate any shared benefits of purchasing and selling to the other system's needs, and ultimately produced a more aligned, cost-effective joint system. Both systems benefit from energy sharing, showing CLFP can purchase excess energy from LPCS, and similarly LPCS can purchase energy from CLFP.

Table 08-13 contains the amount of energy transfers between CLFP and LPCS in the CLFP and LPCS Base Energy Scenario.

Table 08-13
Joint CLFP + LPCS Resource Portfolios— Energy Transfers (MWh)

Joint CLFP + LPCS Energy Transfers (MWh)		
Year	CLFP Purchases from LPCS	LPCS Purchases from CLFP
2026	185,412	97,935
2027	16,150	582,695
2028	4,101	518,557
2029	376,038	26,939
2030	356,854	32,090
2031	355,006	29,581
2032	298,680	51,169
2033	501,072	11,082

8.5.4 Alternative Standalone and Joint CLFP & LPCS Resource Portfolios

Alternative joint CLFP Base and LPCS resource portfolios were created by running scenarios 11-13. The alternative combined CLFP and LPCS resource portfolio was very similar to the base combined system portfolios. In 2029, in the Alternative CLFP and LPCS Energy portfolio, 71 MW of RICE and 50 MW of BESS were selected in the CLFP portion, and 649 MW CCCT and 600 MW of wind were selected in the LPCS portion. The Alternative CLFP and LPCS Standalone portfolios also selected at least 36 MW of RICE and 50 MW of BESS, among other resources, in the NTN.

Table 08-14 contains the Capacity Expansion modeling results for the alternative scenarios.

Table 08-14
Joint CLFP Base & LPCS Plan Resource Portfolios—Alternative Sensitivity Analysis

Cheyenne Light Resource Portfolios – Sensitivity Analysis (MW)				
Year	Alternative CLFP Standalone	Alternative LPCS Standalone	Alternative CLFP + LPCS Energy	
			CLFP	LPCS
2026				
2027				
2028				
2029	71 MW RICE 50 MW BESS	214 MW RICE 250 MW BESS 600 MW Wind	71 MW RICE 50 MW BESS	649 MW CCCT 600 MW Wind
2030				
2031		71 MW RICE		100 MW Wind
2032				
2033	36 MW RICE -60 MW Wygen I		36 MW RICE -60 MW Wygen I	
2034	71 MW RICE	143 MW RICE 100 MW Wind	71 MW RICE	
2035				
2036				
2037				
2038				
2039				
2040	-90 MW Wygen II 90 MW Wygen II NG		-90 MW Wygen II 90 MW Wygen II NG	
2041				
2042				
2043				
2044		36 MW RICE 200 MW Wind		200 MW Wind
2045				

Table 08-15 contains the amount of seasonal firm market purchases included in each alternative scenario, corresponding to the scenario table above.

Table 08-15
Alternative Joint Resource Portfolios—Seasonal Firm Market Purchases

Joint Resource Portfolios – Seasonal Firm Market Purchases (MW)				
Year	Alternative CLFP Standalone	Alternative LPCS Standalone	Alternative CLFP + LPCS Energy	
			CLFP	LPCS
2026	50	0	50	0
2027	50	0	50	0
2028	50	0	50	0
2029	25	0	25	0
2030	25	0	25	0
2031	25	0	25	0
2032	50	0	50	0
2033	50	0	50	0

8.5.5 Discussion of Resource Portfolios

A common theme from all the resulting portfolios is the selection of RICE and BESS in the near-term need, and additional RICE, as well as the conversion of Wygen II to natural gas in the outer years.

The Base Plan results in 36 MW of RICE and 50 MW of BESS in 2029, additional RICE in the mid-2030s, and then the conversion of Wygen II to natural gas in 2040. Outside the NTN, the High Gas scenario selects more wind instead of gas, due to the impact of higher gas prices. The Low Load scenario builds less gas overall, including no selection of RICE until later in the planning period, and some wind in the mid-2030s. This is due to the impact of a smaller capacity shortfall due to a lower load projection. Conversely, the High Load scenario selects more RICE in the NTN due to the impact of a larger capacity shortfall from increased loads.

The environmental House Bill 200 scenarios continue to select the same amounts of RICE and storage in 2029 and build additional RICE in the NTN to help offset the reduction in net generation output because of the auxiliary power consumed by the carbon capture equipment.

The joint CLFP and LPCS scenario is comprised of sub-portfolios for each CLFP and LPCS system. First, in the CLFP and LPCS Base Energy scenario, the resource portfolio includes 36 MW RICE and 50 MW BESS in CLFP and 649 MW CCCT and 600 MW wind in LPCS in 2029. The LPCS loads, by contrast, are much larger than retail CLFP load, which is the reason why larger resources were selected. Additionally, the

additional wind resources in the LPCS portion contribute to the renewable energy targets of some of these large customers. In the joint CLFP and LPCS Base Energy portfolio, both sub-systems are required to meet their own capacity requirements. Additionally, the LPCS Standalone scenario selects 214 MW RICE, 200 MW BESS, and 600 MW of wind in 2029. Because the resource portfolio from the CLFP Base Plan and the CLFP portion of the joint CLFP and LPCS Base Energy scenario are the same for the NTN, there is little risk in proposing to start planning at a combined level.

Lastly, the alternative portfolios show expected results given the increase in load in the underlying ITS load forecast, as compared to the corresponding base scenarios. The Alternative CLFP Standalone portfolio builds more RICE in 2029. The Alternative LPCS Standalone portfolio shifts the timing for the RICE and BESS resources. The Alternative CLFP and LPCS Energy portfolio selects more RICE in the NTN.

8.5.6 Present Value Revenue Requirements

Production cost modeling and was performed on the thirteen 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, and economy energy price. The cost-benefit analysis results are described below.

Figure 08-2 contains the PVRR for each standard Cheyenne Light resource portfolio.

Figure 08-2
Present Value Revenue Requirements for Cheyenne Light Resource Portfolios

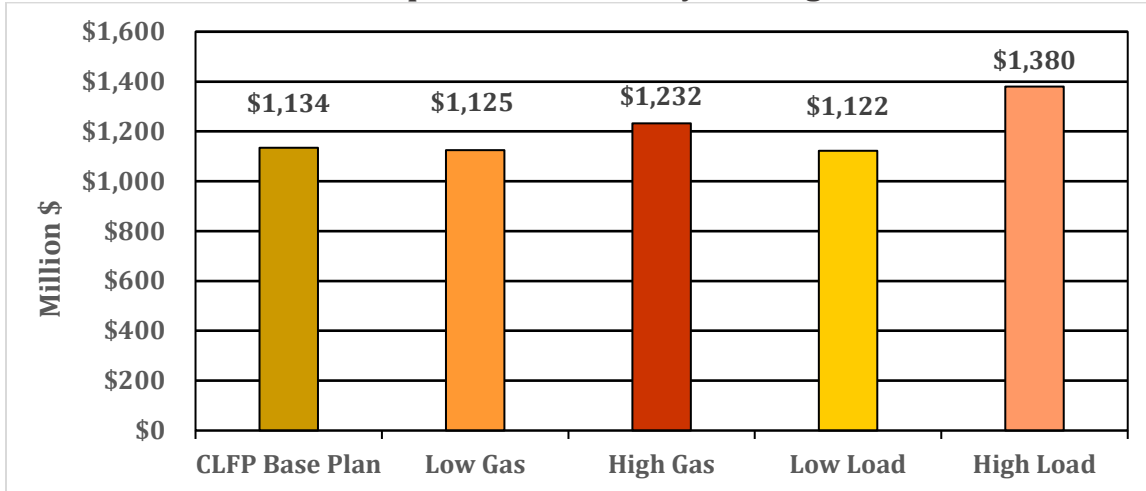


Figure 08-3 contains the PVRR for each environmental Cheyenne Light resource portfolio.

Figure 08-3
Present Value Revenue Requirements for Cheyenne Light Environmental Resource Portfolios

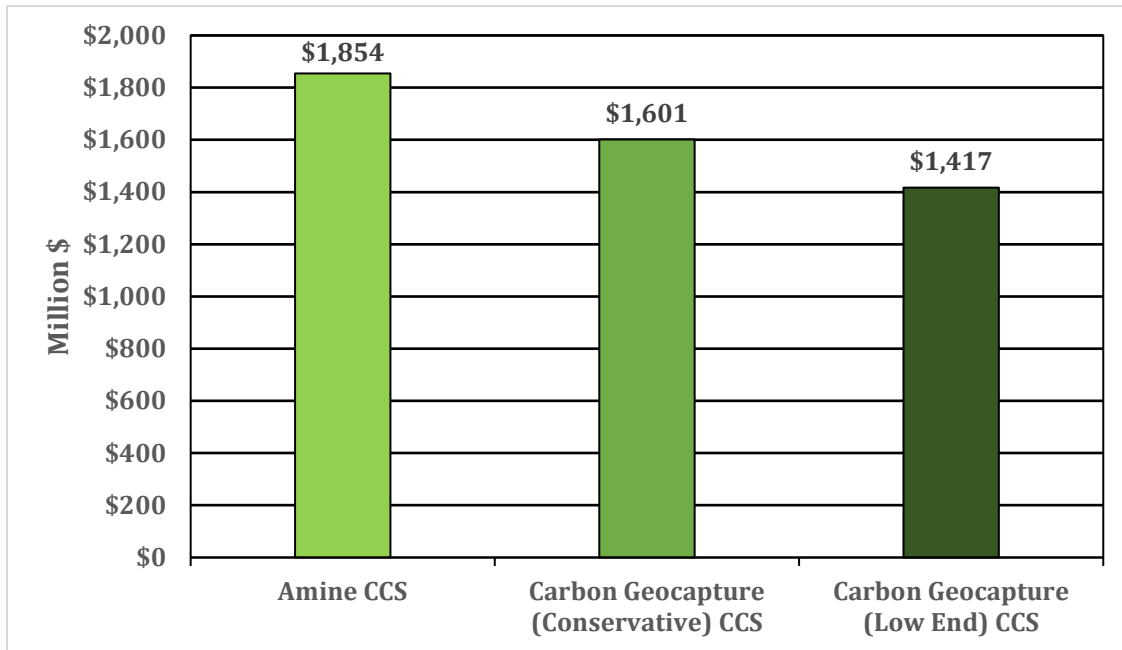


Figure 08-4 contains the PVRR for each LCPS resource portfolio.

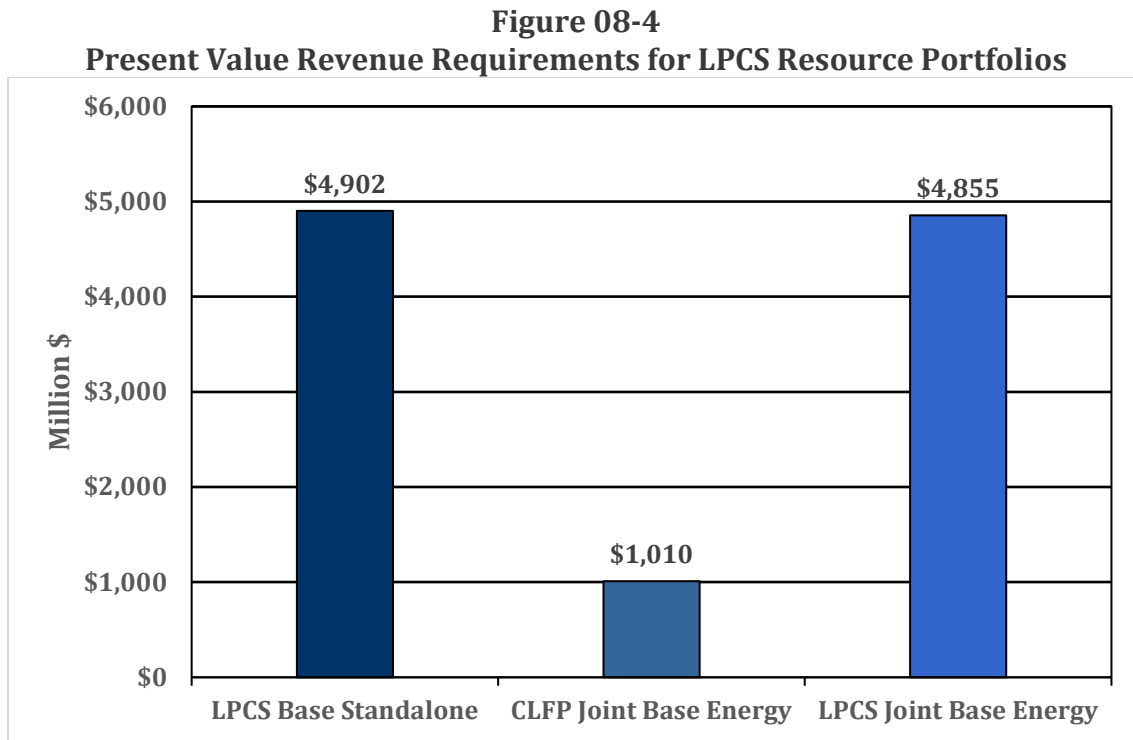
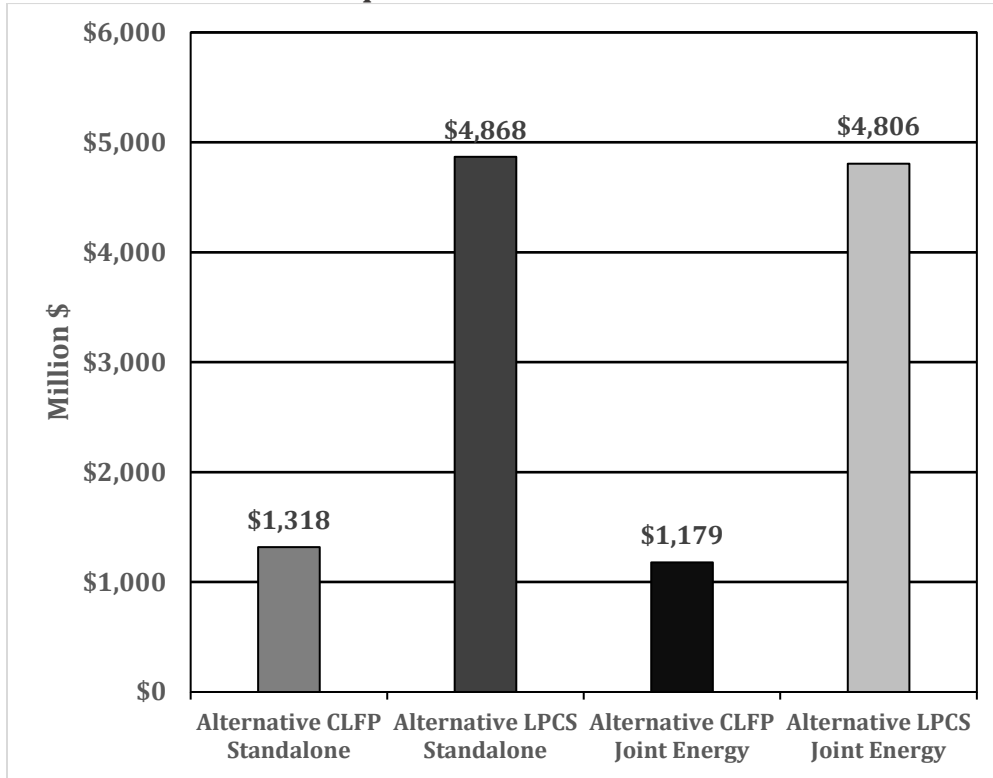


Figure 08-5 contains the PVRR for each alternative resource portfolio.

Figure 08-5
Present Value Revenue Requirements for Alternative Resource Portfolios



For the Cheyenne Light retail customers, Portfolio 10, CLFP and LPCS Base Energy scenario, is the lowest-cost portfolio based on the PVRR analysis. This is due to the portfolio being able to solve for energy sharing between the CLFP and LPCS systems jointly. The energy sharing benefits of this plan are further reflected in the lower PVRR as compared to the CLFP Base Plan. Both portfolios have identical CLFP resource builds, but because of the energy sharing, the dispatch of the CLFP and LPCS Base Energy portfolio is more economic. These portfolios indicate some of the potential PVRR benefits for Cheyenne Light customers by moving from traditional standalone planning to joint energy planning. When looking at planning for both joint system PVRRs combined as compared to the aggregated standalone systems (\$5,865 million Portfolio 10 scenario PVRR total, and \$6,036 Portfolios 1 and 9), the benefits of long-term joint energy planning are illustrated. In order to capture these joint benefits, additional planning will need to occur to ensure all Cheyenne Light customers benefit from this joint planning and that it does not conflict with any current tariff provisions or requirements for the LPCS rate schedule.

As described above, Table 08-16 illustrates the similarities between the optimized CLFP Base Plan and CLFP and LPCS Base Energy portfolios, and resultant PVRRs.

Table 08-16
Cheyenne Light and LPCS Standalone and Joint
Resource Portfolios and Present Value Revenue Requirements

Year	CLFP Standalone	LPCS Standalone	CLFP + LPCS Joint Energy	
			CLFP	LPCS
2029	36 MW RICE 50 MW BESS Storage	214 MW RICE 200 MW BESS Storage 600 MW Wind	36 MW RICE 50 MW BESS Storage	649 MW CCCT 600 MW Wind
2030		71 MW RICE		
2031				100 MW Wind
2033	36 MW RICE -60 MW Wygen I	50 MW BESS Storage	36 MW RICE -60 MW Wygen I	
2034	71 MW RICE	143 MW RICE 100 MW Wind	71 MW RICE	
2040	-90 MW Wygen II 90 MW Wygen II NG		-90 MW Wygen II 90 MW Wygen II NG	
2043		36 MW RICE		
2044		200 MW Wind		200 MW Wind
PVRR	1,134,497	4,902,172	1,009,666	4,855,065

Examining the standard scenarios, the least-cost portfolio is Low Load. However, the Base Plan and Low Gas portfolios have similar PVRR's resulting from similar resource builds. The Low Load portfolio does delay some of the gas builds in the near term need, and even replaces some gas with wind in the outer years. The High Gas and High Load scenarios have increased PVRRs due to the additional wind and gas resources that are needed for these effects.

To better understand the potential implications for customers, Cheyenne Light conducted an analysis of the Wyoming House Bill 200 for informational purposes. The environmental House Bill 200 scenarios (Portfolios 6-8) have higher PVRRs than the standard scenarios (Portfolios 1-5) due to increased cost from adding carbon capture to Wygen II. This shows a greater cost for customers to comply with Wyoming House Bill 200⁷⁵. Adding carbon capture leads to higher capital cost from installing the carbon capture equipment as well as replacing the net load reduction from the carbon capture equipment. It would also lead to higher operating costs for Wygen II due to operating the carbon capture equipment and storing the carbon after it's been captured. Three scenarios examining different carbon capture

⁷⁵ While Cheyenne Light currently has a Commission-approved final Standard of zero percent, the modeling conducted in this resource plan provides an avenue for future compliance greater than zero percent. The Company will continue to monitor and assess the risk and timing of any future compliance requirements to ensure that those needs are cost-effectively met.

technologies and costs resulted in showing the continued exploration of this technology is valuable. Not only have costs declined through switching from amine to Carbon GeoCapture, the low-end estimate, combined with 45Q tax credits, provides a PVRR that begins to close the gap between that and the next highest PVRR, the High Gas portfolio, resulting in a \$37 million delta. There was no difference between the CLFP Base Plan and CLFP and LPCS Base Energy portfolios and the HB200 portfolio in 2029 builds, meaning both plans will be compliant with HB200 during the beginning of years of the near term planning period. This demonstrates the CLFP and LPCS Base Energy portfolio will meet the requirements of House Bill 200, and potential risk mitigation could be addressed through future carbon capture conversion considerations. Cheyenne Light will continue to monitor these rules in the future to ensure compliance, while striving to keep customer costs low as long as possible.

The alternative sensitivities with increased ITS load were intended to identify resource builds if some of the forecasted LPCS load instead is requested by the LPCS customer to be served as ITS load pursuant to the LPCS rate schedule which requires a minimum amount of load to be placed on ITS, but does not specify a maximum amount of ITS service that can be requested by the LPCS customer. For the Alternative CLFP Standalone, the increase from 50 MW to 75 MW of ITS load resulted in additional RICE resources, driving the PVRR increase as compared to the CLFP Base Plan. The Alternative LPCS Standalone PVRR has a slight decrease due to the reduction in load needed to be served as compared to the LPCS Standalone scenario. The alternative joint energy planning sensitivity (Portfolio 13) has similar impacts as the joint energy planning scenario (Portfolio 10), where PVRRs are directionally similar between the two sets. For alternative joint energy planning scenario, the shift of load from LPCS to CLFP results in an increased PVRR for CLFP and decrease for LPCS.

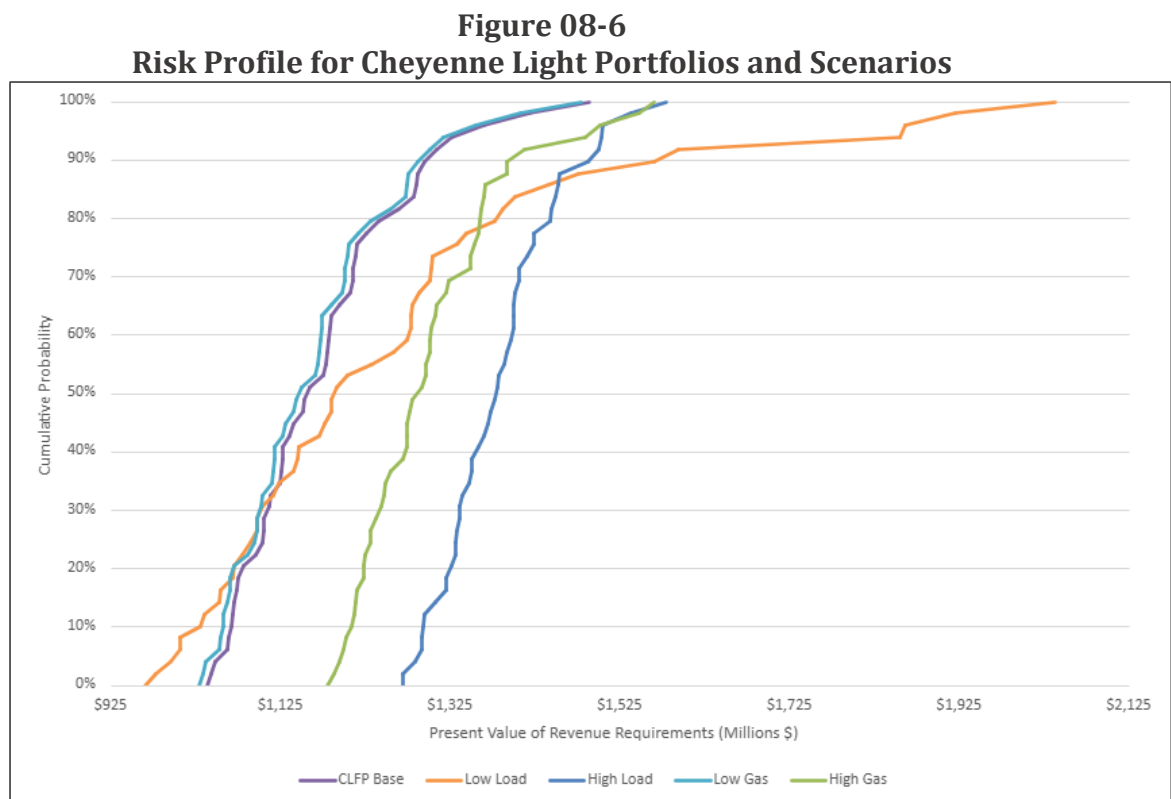
8.6 Risk Analysis

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 EnCompass software performed stochastic analysis on a subset of the Cheyenne Light 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 capital cost, 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. The analysis examines the costs of each resource portfolio assuming different “futures” and tabulates the PVRR expected for each of them. A risk profile for each resource portfolio is then constructed using all of those “future” PVRR

points. This allows each portfolio's economic performance to be evaluated across a wide range of probable market conditions.

The results of each portfolio for each scenario using stochastic inputs are aggregated to form probability distributions for each said scenario. Figure 08-6 illustrates the cumulative probability distributions for the PVRR for the first 5 scenario-optimized portfolios.



The CLFP Base portfolio, similar to the Low Gas portfolio, shows moderate distribution, indicating moderate variability, but the lowest expected PVRRs among the stochastic outcomes (furthest to the left). In contrast, the High Load portfolio exhibits high PVRR values, but relatively concentrated distribution. This indicates it has the lowest variability across the stochastic outcomes, but the highest costs. The High Gas is similar, but slightly less expensive. Lastly, the Low Load portfolio displays the widest spread of distribution, indicating it has the greatest uncertainty across the stochastic outcomes. The higher uncertainty of the Low Load portfolio can be attributed to the reduced amount of resources that were procured when measured across especially higher simulations of load.

8.7 The Selected Preferred Plans

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.

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

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. From that, a preferred resource plan was selected for Cheyenne Light.

The Cheyenne Light preferred plan (Cheyenne Light and LPCS Joint Energy Sharing) calls for the Cheyenne Light addition of 122 MW of new resources during the near-term need period. This consists of 36 MWs of RICE and 50 MW of energy storage in 2029 and 36 MWs of RICE in 2033. RICE units and energy storage are the most cost-effective option to meet the Company's capacity needs. In addition to providing capacity, the RICE units will provide operating efficiency. RICE units offer quick start capabilities and are efficient when operating in limited amounts. Energy Storage and RICE units provide much needed flexibility to maintain reliability.

8.8 The Action Plan

The Wyoming Commission's *Chapter 7: Integrated Resource Plan Rules* sets forth in Section 6.(b).(xiii) sets forth the required contents for inclusion in the development of an IRP Action Plan filed with the Commission. The resultant Action Plan, through its assumptions and conclusions, delivers reliable, cost-effective service to customers throughout the near-term need. The assumptions described in Section 6, Appendix E, and Section 7 demonstrate system reliability, and the cost-benefit analysis is described in the PVRs in Section 8.5.6. The Preferred Plan, Section 8.7, and this Action Plan illustrate these collective impacts.

8.8.1 Action Plan Overview

The Cheyenne Light preferred plan selects the same resources as the Cheyenne Light Base plan, eliminating any potential risk surrounding future joint energy planning. To further mitigate any resource acquisition risks, Cheyenne Light, as a part of its Action Plan, will only pursue the immediate 2029 resources, 36 MW of RICE and 50 MW of energy storage, and continue to evaluate additional resource opportunities for

the remaining 107 MW need expected to occur in 2033 and 2034. Shortfalls experienced prior to 2029 will be addressed through procuring firm market purchases.

The Wyoming Reliable and Dispatchable Low-Carbon Energy Standards (House Bill 200)⁷⁶ could have an impact on the Cheyenne Light generation fleet. While Cheyenne Light currently has a Commission-approved final Standard of zero percent,⁷⁷ the modeling conducted in this resource plan provides an avenue for future compliance greater than zero percent. The Company will continue to monitor and assess the risk and timing of any future compliance requirements to ensure that those needs are cost-effectively met.

8.8.2 Wyoming Environmental and Economic Externalities

The resources identified in this IRP and described in the Action Plan may have environmental externalities, such as air quality implications. Environmental impacts will be assessed when a resource has been selected and a resource site location has been determined. Additional details on environmental externalities will be supplied in future filings with the Commission, such as Certificate for Public Convenience and Necessity.

Due to the identification and construction of new generation resources, Cheyenne Light anticipates positive economic externalities to occur from the Action Plan. More specifically, the Action Plan identifies \$309 million in new capital investment, which will create approximately \$1 million in new and ongoing property tax revenue for Wyoming communities. It is reasonable to expect the construction of new generation resources will also deliver short-term positive economic externalities, such as temporary construction jobs, a boost in sales tax revenues, and other direct and indirect economic benefits. However, Cheyenne Light has elected not to expend additional funds to study and quantify these potential benefits for inclusion in this IRP.

8.8.3 Community and Employee Transition Plan

Cheyenne Light has not developed a Community and Employee Transition Plan as part of its Action Plan as Cheyenne Light's Action Plan does not identify early retirement of any Company-owned generation resources. Section 8.8.2 shows positive economic externalities resulting from the Action Plan; therefore, a Community and Employee Transition Plan is not necessary.

⁷⁶ Wyoming Statute § 37-18-101-102.

⁷⁷ Docket No. 20003-251-EA-25 (Record No. 17783). Company-owned generation must generate zero percent of electricity using carbon capture.

8.8.4 Resource Acquisition Plan

The Energy Resource Procurement process is provided in Wyo. Stat. § 37-2-136, which requires significant energy resources (defined as 100 MW or greater) to complete a solicitation process reviewed and approved by the Commission. The total new generating capacity identified in the Action Plan is 86 MW and is therefore not a significant energy resource, exempting it from Wyo. Stat. § 37-2-136 requirements.

9. CONCLUSION

The IRP identifies that the forecasted future needs of Cheyenne Light will be best met through a balanced mix of generation resources, including coal, natural gas, wind and energy storage. This IRP includes an analysis of the resource needs of Cheyenne Light, including the requirements as identified by Chapter 7, Section 6 IRP Rules.

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 and regulatory requirements.

This IRP identified a Cheyenne Light near-term capacity shortfall of 95 MW beginning in 2027. Based on forecasts and analysis, Cheyenne Light recommends the addition of natural gas fired reciprocating internal combustion engines, with a nameplate capacity of 36 MW, and 50 MW of energy storage in the near-term need planning period as the preferred, least-cost and least-risk alternative to meet the identified resource need. The energy storage and natural gas resources will economically provide firm capacity and will be available to quickly adapt to any changes in load and resource needs.

Due to the timing and resource needs for Cheyenne Light, Cheyenne Light recommends a combination of this preferred plan and the continued evaluation of additional resource opportunities for the resource needs identified to occur in 2033 and 2034 to meet the identified capacity shortfalls in the IRP. As a point of reference, this IRP does not address any LPCS capacity needs which are handled separately under customer specific contracts per the LPCS Rate Schedule. Pursuant to the LPCS Tariff provisions, LPCS customers must have their own Eligible Capacity Resources (as defined in the LPCS Tariff) that are greater than or equal to 115% of the customer's actual peak monthly load served. In addition, there are ring fencing provisions contained in the LPCS Tariff which provide that LPCS customers will have costs assigned to them individually based upon cost causation principles that are based on the characteristics of the electric service that has been contracted for by the customer, including the costs of any Eligible Capacity Resources.

Cheyenne Light is in the beginning stages of developing the required applications for approval by the Wyoming Public Service Commission for approval to construct the

36 MW of reciprocating internal combustion engines (RICE) and 50 MW energy storage identified in the preferred plan, and anticipates making these filing in the second half of 2026 or the first half of 2027. The RICE units and energy storage will likely be located in Cheyenne, Wyoming. Cheyenne Light is targeting an in-service date of 2029 for the energy storage and RICE units so that it can continue to provide safe and reliable energy to its customers in Wyoming.