APPLICATION FOR A CERTIFICATE OF
PUBLIC CONVENIENCE AND NECESSITY

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

JOINT APPLICATION OF CHEYENNE	)	
LIGHT, FUEL & POWER COMPANY	)	
AND BLACK HILLS POWER, INC. FOR	)	**DOCKET NO 20003-___-EA-11**
A CERTIFICATE OF PUBLIC	)	**RECORD # ________**
CONVENIENCE AND NECESSITY FOR	)	
A GAS-FIRED ELECTRIC	)	**DOCKET NO 20002-___-EA-11**
GENERATING POWER PLANT AND	)	**RECORD # ________**
RELATED FACILITIES	)	
	)	

The above-named Applicants submit this Application for a Certificate of Public Convenience and Necessity, pursuant to § 37-2-205, Wyoming Statutes and Sections 203, 204, 205, and 206 of Chapter II of the Rules of the Public Service Commission of Wyoming as follows:

1. Cheyenne Light, Fuel & Power Company, which is incorporated under the laws of the State of Wyoming ("Cheyenne Light") and duly authorized to do business in the state of Wyoming, and with offices located at 108 West 18th Street, Cheyenne, Wyoming 82001, proposes to construct and operate a facility at Cheyenne, Wyoming and Black Hills Power, Inc., which is incorporated under the laws of the State of South Dakota ("Black Hills Power") (Cheyenne Light and Black Hills Power collectively known as "Applicants") and duly authorized to do business in the state of Wyoming, and with an office located at 409 Deadwood Ave, South Dakota, 57702, proposes to construct and operate a facility at Cheyenne, Wyoming.

2. Attached hereto and incorporated into this Application is the information required by Sections 204, 205, and 206 of Chapter II of the Rules of the Public Service Commission of Wyoming, together with pre-filed testimony.

3. Due to the construction period of this proposed project and the need to finalize construction contracts and order equipment and components, Applicant respectfully requests a decision regarding this Application within ten months of the Application.

4. Persons to whom all filings, pleadings and correspondence in connection with this Application are to be sent are as follows:

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EXHIBIT
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WHEREFORE, Applicants pray that the Commission enter an Order granting Applicant a Certificate of Public Convenience and Necessity authorizing the construction, operation, and maintenance of the Gas-Fired Combustion Turbine Electric Generating Power Plant and Related Facilities, including a high pressure gas line and transmission line, as described herein.

Dated this 1 day of November, 2011.

Cheyenne Light, Fuel & Power Company

By Mark Stege
Mark Stege
Vice President, Operations
Cheyenne Light, Fuel and Power Company

Black Hills Power, Inc.

By Richard C. Loomis
Richard C. Loomis
Vice President, Operations
Black Hills Power, Inc.

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EXECUTIVE SUMMARY

Request for Approval. Cheyenne Light, Fuel & Power Company (herein "Cheyenne Light") and Black Hills Power, Inc. ("Black Hills Power") (referred to collectively as "Applicants") request approval to construct in Cheyenne, Wyoming, a natural gas-fired generating power plant providing a total of 132 MW. The power plant includes a natural gas-fired combustion turbine generator and a combined cycle unit. In addition, ancillary equipment, electrical transmission and natural gas lines and related equipment, land and buildings (referred to collectively with the power plant, as the "Facility") are necessary to make the plant operational and compliant with environmental requirements. Applicants are affiliates in that both are subsidiaries of Black Hills Corporation.

Site Description. The proposed site of the Facility is located on the southeast side of the City of Cheyenne, Wyoming. It is an undeveloped parcel of approximately 250 acres and is characterized by gently rolling hills. The proposed site has an adequate and efficient water supply, access to interstate natural gas pipelines, and access to and availability of electric transmission.

Plant Description. Applicants propose to install:

1. One natural gas-fired combustion turbine generator (CTG) to be wholly owned by Cheyenne Light,
2. A Cheyenne Light and Black Hills Power jointly-owned combined cycle (CC) that includes two combustion turbine generators, two heat recovery steam generators and one steam turbine (the CC and CTG shall be referred to as the "Plant"),
3. A wholly-owned Cheyenne Light fuel gas supply line ("Gas Pipeline").
4. A wholly-owned Cheyenne Light transmission line interconnecting the CC and CTG to Cheyenne Light's existing 115 kV transmission system ("Transmission Interconnection"), and
5. Cheyenne Light and Black Hills Power jointly-owned ancillary equipment, land and buildings, a substation, and other assets that do not fall within the definition of the above four categories ("Common Capital Assets").

The Plant is designed to fire natural gas only and will be equipped with low-emission systems.

Fuel gas will be supplied by the Gas Pipeline that will transport natural gas via a 12" diameter high pressure transmission line that will interconnect with an interstate transmission pipeline near the Wyoming/Colorado border. The Gas Pipeline to be constructed by Cheyenne Light will be approximately 11 miles in length.

Potable and makeup water for the Facility will be sourced from the Cheyenne Board of Public Utilities (CBOPU), and wastewater will be discharged to the CBOPU municipal wastewater treatment plant, which is adjacent to the Facility or be discharged to either Crow Creek or Dry Creek with a NPDES discharge permit.

Applications for the necessary air permits have been filed.

Upon receipt of necessary governmental approvals, construction activities will commence in the fourth quarter of 2012. The estimated in-service commercial operation date is scheduled for summer 2014.

Facility Estimated Cost and Ownership. The estimated total cost to construct the Facility is $237 million. Of the total cost, Cheyenne Light will pay $145.3 million and Black Hills Power will pay $91.7 million. Cheyenne Light will recoup a portion of its capital cost over time from the payment by Black Hills Power of 42% of Cheyenne Light's capital costs and operating expenses on a revenue requirement basis relating to the Gas Pipeline and Transmission Interconnection. Accordingly, the effective capital cost to Cheyenne Light will be $135.7 million.

The following table summarizes the estimated cost and ownership of the Facility:

Asset	Net Output	Ownership	Estimated Cost	Notes
1. Combustion Turbine Generator	37 MW	Cheyenne Light	$49.0M	
2. Combined Cycle	95 MW	Cheyenne Light 42% (40MW)($58.7M) Black Hills Power 58% (55MW)($81.1M)	$139.8M	Ownership based on MW
3. Gas Pipeline		Cheyenne Light	$15.9M	BHP to pay 42% of CL's capital costs and operating expenses on revenue requirement basis
4. Transmission Interconnect		Cheyenne Light	$7.0M	
5. Common Capital Assets		Cheyenne Light 58% ($14.6M) Black Hills Power (42%)($10.6M)	$25.2M	Ownership based on total MW by entity divided by Facility's total MW
Total	132 MW Total Plant Net Output		$237M Total Estimated Cost of Facility	

Resource Need and Selection. The proposed joint-ownership of a combined cycle resource by Cheyenne Light and Black Hills Power represents a win-win opportunity for each utility that was not on the planning horizon just months ago.

By way of background, Cheyenne Light recognized that it will need new electric resources to offset load growth and the expiration of long-term power purchase contracts occurring over the next several years. Cheyenne Light currently owns one generating resource, the coal-fired Wygen II unit, and purchases the remainder of its requirements through power purchase agreements (PPAs) for coal-fired, natural gas-fired and wind resources. All of Cheyenne Light's PPAs expire within the 20 year planning horizon.

Accordingly, in June 2011, Cheyenne Light completed an integrated resource plan (IRP) in anticipation of increased customer load and expiring PPAs. The IRP identified a capacity deficit of 93 MW in 2014 and exceeding 150 MW by the end of the 20-year plan. The Cheyenne Light IRP identified a preferred plan that included the addition of three combustion turbine generators for Cheyenne Light customers by 2014. Consistent with the IRP, Cheyenne Light filed a Certificate of Public Convenience and Necessity on August 1, 2011 with the Wyoming Public Service Commission (WPSC) to construct three combustion turbine generators on a site in Cheyenne, Wyoming.

As Cheyenne Light was filing with the WPSC, Black Hills Power was beginning work on an IRP to identify the future resource needs of its customers. The future resource needs of Black Hills Power are driven primarily by the impact of environmental regulatory requirements on its existing generating facilities. Based on regulatory requirements and economics, the Ben French, Neil Simpson 1 and Osage coal-fired units owned by Black Hills Power will need to be retired in 2014. In addition, certain PPAs of Black Hills Power will terminate over the 20-year IRP planning horizon.

Work progressed on the IRP for Black Hills Power, and the preferred plan identified in the IRP included the conversion of a combustion turbine generator to combined cycle operation, in the 2014 time frame. As a result of the preferred plan in Black Hills Power's IRP, consideration was given to whether siting a combined cycle resource in Cheyenne would present an opportunity for both Cheyenne Light and Black Hills Power.

To assess the benefits and risks of a jointly-owned CC unit, the Applicants undertook additional analysis and modeling to determine the financial impact on the completed resource plans of Cheyenne Light and Black Hills Power. The Applicants analyzed and considered whether the increased initial capital cost per kW of a combined cycle, as compared to combustion turbine generators, would be offset by the benefits associated with a more cost efficient combined cycle.

The result of the analysis indicated that a jointly-owned CC unit, one CTG owned by Cheyenne Light, and additional firm market purchases resulted in lower present value of revenue requirements than the resource scenario of three CTGs identified in Cheyenne Light's original IRP.

This resource mix – a jointly-owned CC unit, one CTG owned by Cheyenne Light and additional firm market purchases – includes operational and environmental benefits, market risk benefits and the benefit of resource diversity. A CC unit is an intermediate resource that provides the following benefits to Cheyenne Light and Black Hills Power:

- operates at a lower heat rate than a combustion turbine generator;
- lowers environmental emissions;
- reduces utility exposure to future environmental mandates or taxes;
- reduces reliance on the economy energy markets;
- provides a hedge against future natural gas prices

- addition of an intermediate resource diversifies the resource mix of both Applicants; and
- provides economical system and wind regulation.

Construction of a CC unit in Cheyenne in conjunction with the new construction of a CTG is more efficient as compared to use of an existing CTG. In addition, the availability of water and a gas fuel supply favored locating the jointly owned CC in Cheyenne. A 2007 dispatch agreement between the Applicants provides the ability to exchange energy without a resulting transmission cost between their respective service territories.

For the reasons set forth above and in this Application, it was decided to file a motion to withdraw the August 1, 2011 Cheyenne Light CPCN application and file this joint application.

Financial Condition of Applicants; Financing. The financial integrity of both Cheyenne Light and Black Hills Power is sound, and each entity has the ability to finance its capital costs related to the Facility. The exact type and timing of long term financing by Applicants has not been finally determined but is expected to be through assignment of Black Hills Corporation debt, issuance of first mortgage bonds by Cheyenne Light and Black Hills Power for their respective capital investment and/or equity invested by Black Hills Corporation.

Other Considerations. The Applicants have elected to construct the Facility to serve their customers in lieu of entering into long-term power purchase agreements. Reasons for this decision include price stability beyond the term of the power purchase agreement, a regulated rate of return approved by the WPSC, operational benefits and security realized by utility-owned generation, and the risks that may be associated with purchased power.

For the reasons discussed in this Application, the Applicants believe that the construction of the Facility is prudent and in the best interests of the customers of Cheyenne Light and Black Hills Power.

<u>Subsection 204(a)[1].</u> The name and address of the applicant

The applicants are Cheyenne Light and Black Hills Power. Cheyenne Light is a Wyoming corporation with offices located at 108 West 18th Street, Cheyenne, Wyoming 82001. Black Hills Power is a South Dakota corporation with offices located at 409 Deadwood Ave, South Dakota, 57702.

<u>Subsection 204(b).</u> The type of plant, property or facility proposed to be constructed.

The generation facility proposed to be constructed by the Applicants will be located on a parcel of land located within the City of Cheyenne in Laramie County, Wyoming. The Applicants anticipate that the proposed facility site will include up to 250 acres. The Applicants propose to install a natural gas-fired simple cycle combustion turbine generator (CTG) to be wholly-owned by Cheyenne Light and a jointly-owned combined cycle combustion turbine (CC) that includes two (2) combined cycle combustion turbine generators (CC CTG), two heat recovery steam generators (HRSG) and one steam turbine generator (STG), providing a total net output of 132 MW[2] at annual average ambient conditions. In addition, the Facility will include a substation, transmission line interconnecting the Plant to Cheyenne Light's existing 115 kV transmission system, fuel gas supply system and ancillary equipment.

The Plant is designed to fire natural gas only and will be equipped with low-emission combustors, selective catalytic reduction (SCR) to control nitrogen oxides (NOx) emissions, and an oxidation catalyst to control carbon monoxide (CO) and volatile organic compounds (VOC) emissions. An inlet air cooling system is included with each CTG and CC CTG to improve performance at higher ambient temperatures.

Fuel gas for the Plant will be supplied by Cheyenne Light's natural gas system via a 12" diameter high pressure transmission line interconnecting with an interstate transmission pipeline. Though it has yet to be determined which interstate pipeline the Plant will interconnect with, the selection will be based on reliability, flexibility and cost-effectiveness.

The Plant will interconnect with Cheyenne Light's 115kV electrical transmission system.

Potable and makeup water for the Facility will be sourced from the CBOPU. Wastewater will be discharged to the CBOPU municipal wastewater treatment plant which is adjacent to the Facility or possibly to Dry Creek through a Surface Water Discharge permit issued by the Wyoming Department of Environmental Quality (WDEQ).

Affiliates of the Applicants have successfully constructed and operated other natural gas-fired generation facilities that are very similar to the Facility. Black Hills Service Company (BHSC), an affiliate, is currently constructing a combined cycle gas turbine facility in Pueblo, Colorado that includes LM6000 combustion turbines. The combustion turbine model selected for the Facility will be based on cost of generation, efficiency, reliability and manufacturer's delivery schedule.

[1] References to subsections refer to Sections 204, 205 and 206 of Chapter II of the Rules of the Public Service Commission of Wyoming

[2] Except as otherwise specifically indicated, all references to plant output in this application and testimony indicate net MW output.

<u>Subsection 204(c).</u> A complete description of the facilities proposed to be constructed, including preliminary engineering specifications in sufficient detail to properly describe the principal systems and components; and final and complete engineering specifications when they become available.

The following sections provide a general description of the major systems, equipment, site improvements and infrastructure additions that will be required for operation of the Facility.

1. Mechanical Systems

The principal mechanical systems and equipment required for the Plant are described in the sections below. Several mechanical systems are common to both the CTG and the CC including the fuel gas supply system, ammonia storage system, fire protection and detection system, compressed air system and water systems. The descriptions of these systems are included in the common systems section below. Those components of the CTG's and CC's mechanical systems that differ are categorized in simple cycle and combined cycle sections below.

1.1. Combustion Turbine Generator (Simple Cycle)

The principal mechanical systems and equipment required for the CTG include a combustion turbine and generator, inlet cooling system, emission control modules, fuel gas supply system, compressed air system and several water systems. In general, the mechanical systems and equipment described in this section will, at a minimum, meet the relevant requirements of National Fire Protection Association (NFPA) 70, American Society of Mechanical Engineers (ASME), American National Standards Institute (ANSI) and American Water Works Association (AWWA).

1.1.1. Combustion Turbine Generator

The CTG to be installed at the Facility will have a net capacity of 37 MW at annual average ambient conditions and is designed to provide peaking service. The CTG will combust high pressure natural gas, which in turn drives the electrical generator to produce electrical power.

1.1.1.1.Major Components

A complete list and general description of the major components of the CTG are provided below.

- Combustion turbine
- Generator
- Natural gas-fired inlet air heating units
- Enclosures and freeze protection measures
- Inlet air cooling system
- Carbon dioxide (CO_2) fire protection system
- Turbine control system

1.1.1.2.System Description

The CTG consists of a multi-stage axial compressor and a multi-stage turbine. The engine is equipped with variable inlet guide vanes and an inlet screen to protect against foreign object damage and with a low emissions system to control NO_x.

The Generator is an air-cooled unit operating at 13.8 kV, 60 Hz with a brushless excitation system with permanent magnet generator. Neutral and line side cubicles are included.

The modular inlet air filtration system consists of inlet screens, multiple filtration stages and a silencing section. The inlet filter module also includes a bank of finned tubing (coils) which can be used for inlet air chilling or anti-icing depending on ambient conditions (the combustion turbine inlet air chilling system). The combustion turbine inlet air cooling system helps to maintain the output of the turbine during warm weather.

The inlet air heating system provides heated water to the inlet coils during cold weather conditions to heat the inlet air to the manufacturer's design inlet temperature range to meet emissions guarantees as well as to prevent icing on the unit. The water/glycol mixture is pumped through a natural gas-fired heater before sending it to the coils in the CTG inlet.

The overall design is modular with separate pre-assembled sections for the turbine and generator compartments. The unit is provided with weatherproof, acoustic enclosures. The turbine and generator compartments are fully ventilated with redundant fans and are provided with explosion proof lighting.

The combustion turbine enclosure is protected by a full flooding CO_2 fire protection system. The system consists of high pressure bottle storage located beside each turbine enclosure on a separate skid. If a fire is detected, the system will go into audible and visual alarm, and the fire suppression agent will be introduced into the compartment.

The unit is supplied with a turbine control panel (TCP) suitable for mounting in an indoor, non-hazardous area. The control system features an integrated turbine control system, vibration monitor, digital meter, digital generator protective relay module and a human machine interface (HMI) display of key discrete and analog data. Alarm and shutdown events are displayed on the HMI automatically. Power for the control panel is provided by a dedicated 24V DC battery system with dual 100% capacity chargers.

1.1.2. Emissions Controls

The CTG will be equipped with SCR capability to control NO_x and with a CO catalyst bed sized to control CO and VOC emission as required by an approved air permit.

1.1.2.1.Major Components

The emissions control systems include the following major components:

- SCR system, including ammonia injection system
- Tempering air system
- CO catalyst
- Exhaust stacks

1.1.2.2. General Description

NOx emissions will be controlled by the SCR which will be designed for the application of an aqueous ammonia solution as a reducing agent. The catalyst in presence of a reducing agent decomposes NO_x contained in the flue gas into nitrogen (N_2) and water vapor (H_2O). The CO catalyst will convert CO to CO_2 in the presence of a metal oxidation catalyst. VOC's will be controlled in a similar fashion.

Each SCR arrangement includes 2x100% tempering air fans, intake filter housing and 2x100% seal air cooling fans (only used when the tempering air fans are shut down). The SCR is provided with an ammonia vaporization and flow control skid. The aqueous ammonia distribution system feeding the skids will be equipped with a return line from the skid back to the storage tank.

1.2. Combined Cycle

The CC to be installed at the Facility will have a net capacity of 95 MW at annual average ambient conditions. The principal mechanical systems and equipment required for the proposed CC include two (2) CC CTGs, inlet air evaporative cooling system, two (2) HRSGs, STG, steam surface condenser, fuel gas supply system, cooling tower, fire protection and detection system, chemical feed systems, compressed air system, and several supporting water systems. In general, the mechanical systems and equipment described in this section will, at a minimum, meet the relevant requirements of National Fire Protection Association (NFPA) 70, American Society of Mechanical Engineers (ASME), American National Standards Institute (ANSI) and American Water Works Association (AWWA).

1.2.1. Combined Cycle Combustion Turbine Generators (CC CTG)

The CC CTGs to be installed at the Facility will each have a nominal capacity of about 37 MW at annual average ambient conditions, designed to provide intermediate to base load service. Each CC CTG combusts high-pressure natural gas that is expanded in a turbine, which in turn drives the electrical generator to produce electrical power.

1.2.1.1. Major Components

A complete list and general description of the major components of the CC CTGs are provided below.

- Combustion turbine
- Generators
- Modular inlet air filtration system with evaporative cooling and heating coil
- Inlet gas-fired heater system
- Compressor interstage water injection system
- Enclosures and freeze protection measures
- Auxiliary skids
- CO_2 fire protection system
- Air-cooled auxiliary cooling system

- Turbine control system

1.2.1.2.System Description

Each CC CTG consists of a multi-stage axial compressor and a multi-stage turbine. The engine is equipped with variable inlet guide vanes and an inlet screen to protect against foreign object damage and with a low emissions system to control NO_x. The low emissions system can control NOx emissions by thoroughly pre-mixing the fuel and air, and maintaining optimum conditions within the combustors.

An interstage water injection system boosts engine performance by providing intercooling to the compression process. Demineralized water is injected through spray nozzles between the high and low-pressure compressors, and at the inlet bellmouth.

The Generators are air-cooled, two pole units operating at 13.8 kV, 60 Hz with brushless excitation system with permanent magnet generator. Neutral and line side cubicles are included.

The power output stabilization sends supplementary control signals to the generator's voltage regulator to control power fluctuations and improve the stability of the power system.

The modular inlet air filtration system consists of inlet screens, multiple filtration stages, and a silencing section.

A re-circulating evaporative cooling system is also included in the inlet filter house to cool the ambient air during hot weather conditions. The inlet filter module also includes a bank of finned tubing (coils) which can be used for anti-icing during freezing weather conditions.

The combustion turbine inlet air evaporative cooling system uses plant water to saturate cooling media inside the inlet filter module. As the intake air passes over the saturated cooling media, some of the water evaporates and is absorbed by the air. During the evaporation process, the inlet air is cooled. Water is re-circulated over the media to maintain the cooling effect, and a blowdown stream is rejected to the wastewater collection system to prevent the buildup of dissolved solids on the filter media surfaces.

The gas-fired in-let heater is used to heat a glycol water mixture that is circulated through the finned tube coil in the inlet filter module during weather conditions when there is a possibility of atmospheric water vapor freezing on the filter media. This system is also designed to bring the ambient air temperature injected into the turbine within the temperature range to meet manufacturer emissions guarantees.

Each CC CTG has a self-contained system to reject heat from the oil systems used to lubricate the bearings in the turbine, compressor and generator. It consists of pumps, fans, and a finned tube heat exchanger, and the heat is rejected directly to atmospheric air.

In addition to the inlet air heating system, each unit is provided with freeze protection measures such as an enclosure for the auxiliary skid, heat tracing, piping insulation, and heating exposed instruments and equipment.

The overall design is modular with separate pre-assembled sections for the turbine and generator compartments. The unit is provided with weatherproof, acoustic enclosures. The turbine and generator compartments are fully ventilated with redundant fans and unit heaters and are provided with explosion proof lighting.

The auxiliary skid houses ancillary equipment for each turbine such as the generator mineral lube oil system, turbine synthetic lube oil system, hydraulic oil system, and water wash pump. The skid is located under the inlet air filter. A separate skid is included for the compressor water injection system equipment. All wastewater will go to the wastewater collection and treatment system.

The CC CTG enclosure is protected by a full flooding CO_2 fire protection system. The system consists of high-pressure bottle storage located beside each turbine enclosure on a separate skid. If a fire is detected, the system will go into audible and visual alarm, and the fire suppression agent will be introduced into the compartment.

Each unit is supplied with a freestanding TCP suitable for mounting in an indoor, non-hazardous area. The control system features an integrated turbine control system, vibration monitor, digital meter, digital generator protective relay module, and a HMI display of key discrete and analog data. Alarm and shutdown events are displayed on the HMI automatically. Power for the control panel is provided by a dedicated 24V DC battery system with dual 100% capacity chargers. The TCPs are located in the facility control room.

1.2.2. Heat Recovery Steam Generator (HRSG)

Each HRSG will be designed as a two pressure steam generator without duct firing, and include SCR to control NOx and CO catalyst to control CO and VOC to no greater than the limits in an approved air permit.

1.2.2.1.Major Components

Each HRSG includes the following major components:

- Low pressure (LP) heat transfer section
- High pressure (HP) heat transfer section
- SCR system, including ammonia injection system
- CO catalyst
- Boiler feed pumps
- Ammonia storage and handling system
- Exhaust stack

1.2.2.2.System Description

The LP heat transfer section is supplied with water from the condensate system and heats the water in an LP economizer section to near saturation temperature and stores the water in the LP drum. Water from the LP drum is sent to the LP evaporator section, where it is turned into steam, and returned to the LP drum. Steam from the drum is then sent through a moisture separator and on to the LP superheater section. This superheated LP steam is then transported by the LP steam system to the steam turbine. Water level in the drum is controlled by a blowdown valve, as well as a level control valve upstream of the LP drum.

The HP heat transfer section is supplied with water from the boiler feedwater system, and the boiler feed pumps take suction from the LP drum. The HP heat transfer section heats the water in the HP economizer to near saturation temperature and stores the water in the HP drum. Water from the HP drum is sent to the HP evaporator, where it is turned into steam, and returned to the HP drum. Steam from the drum is then sent through a moisture separator and on to the HP superheater sections. A bypass valve can route some of the steam around one of the sections to control final steam temperature to the steam turbine. Water level in the drum is controlled by a blowdown valve, as well as a level control valve located upstream of the HP economizer.

NOx emissions will be controlled by the SCR which will be designed for the application of an aqueous ammonia solution as a reducing agent. The catalyst in presence of a reducing agent decomposes nitrogen oxides (NOx) contained in the flue gas into nitrogen (N_2) and water vapor (H2O). A separate CO catalyst will be included to convert CO to CO_2 in the presence of a metal oxidation catalyst.

Two (2) 100% capacity, motor driven, horizontal boiler feed pumps are provided for each HRSG, and will be located beside the HRSG casing. The pumps take suction from the LP drum of the associated HRSG, and supply HP feedwater to the HP economizer. A recirculation system is provided to allow the minimum flow for the pumps to be maintained during periods of low feedwater demand by the HRSG.

Drains from the HRSG piping and components are routed to the HRSG blowdown tank, which allows the drains to flash at near atmospheric pressure so that the steam can be vented to atmosphere through a silencer, and the recovered condensate can be recovered and drained into the HRSG blowdown sump. From the sump, the water is pumped to the cooling tower basin.

The HRSG includes interconnecting piping, an insulated external gas-tight casing, stairs, ladders and platforms for operations and maintenance access, and the exhaust stack with the continuous emission monitoring system sensors mounted near its top. It also includes the required pressure relief valves with silencers to limit noise transmission beyond the site boundaries.

1.2.3. Steam Turbine Generator (STG)

The STG takes HP and LP steam from the HRSG, which is conveyed by the HP and LP steam systems, respectively, and expands that steam through the rotating blades to produce rotational energy in the shaft. The shaft is connected to the generator, which converts the rotational energy into electric power. The steam turbine exhausts the steam at vacuum conditions into the steam surface condenser.

1.2.3.1.Major Components

- Steam turbine with HP and LP inlets
- Generator
- Lube oil system with coolers
- Turbine exhaust hood water spray system

- Steam seal system and gland steam condenser
- Electrohydraulic control system
- Turbine generator control system with distributed control system (DCS) interface

1.2.3.2.System Description

The steam turbine is a single casing, axial exhaust, single flow, condensing type with an uncontrolled admission point for LP steam. The HP steam conditions at the turbine inlet are nominally 800 psig and 830°F. The turbine is designed to operate continuously between full load and a minimum of 20% load. It is designed to operate with either inlet throttling or sliding inlet pressure.

The generator operates at 60 Hz with total enclosed water to air-cooling (TEWAC). It has a nominal rating of 30 MVA and operates at 13.8 kV at the generator terminals. It is capable of operating at a lagging power factor of 0.85. It includes a neutral grounding assembly and a brushless exciter system. It is capable of manual or automatic synchronization, and includes the necessary instruments and controls for interfacing with the grid.

The turbine and generator has a self-contained lubrication system which is cooled by water from the auxiliary cycle cooling water system. Redundant pumps for both AC and DC operation are included. The same cooling water is used for generator cooling.

The turbine exhaust hood water spray system is designed to cool the steam in the turbine exhaust under startup and shutdown conditions to prevent over-temperature excursions of the connecting ducting. The steam seal system provides steam to the areas where the shaft penetrates the turbine casing, and limits the in-leakage of air at those points operating below atmospheric pressure. The gland steam condenser uses condensate in a shell and tube heat exchanger to cool excess sealing steam and drains from the turbine, and to remove any non-condensable gases from the turbine drains.

The electrohydraulic control system (EHC) provides the instrumentation and quick operating valves to keep the operation of the turbine generator within expected conditions, and to trip the unit if necessary. The control system also includes a microprocessor-based control system with an operator interface terminal located in the control room. A link is provided to the overall plant DCS to coordinate the control of all plant components.

1.2.4. Steam Surface Condenser

The steam surface condenser receives exhaust steam from the steam turbine and condenses the steam using circulating water flowing through tubes. The condenser shell operates as a vacuum and contains the steam until it is condensed. Any non-condensable gases that enter the condenser are removed by the associated air removal equipment.

1.2.4.1.Major Components

- Surface condenser
- Condensate pumps

- Air removal equipment
- Makeup condensate deaeration section

1.2.4.2. System Description

The surface condenser is a single shell design, with double water pass design and divided water boxes arranged to allow two separate cooling water paths. The condenser hotwell extends the full length of the unit and is designed to hold a 5 minute condensate supply at full load. Turbine exhaust is condensed on the tube surfaces, and falls by gravity into the hotwell.

Three (3) 50%-capacity, multistage, vertical can-type condensate pumps take suction from the condenser hotwell and supply the condensate system. A minimum flow recirculation system is provided to protect the pumps from damage during low demand of condensate flow. Condensate is provided to the gland steam condenser, the steam bypass systems, and the HRSG LP Economizer.

The Condenser Air Extraction system uses two (2) 100%-capacity, motor driven, liquid ring vacuum pumps, with associated auxiliaries, to maintain the condenser vacuum by extracting and condensing some of the steam along with the non-condensable gases that have leaked into the vacuum spaces. One (1) vacuum pump operates to maintain vacuum once the steam turbine is operating, but both are operated together to create the vacuum after a shutdown, referred to as "hogging" operation. The vacuum pumps are mounted on a skid adjacent to the condenser shell, and non-condensable gases are discharged to the atmosphere through a silencer.

The condenser hotwell is also used for cycle makeup with demineralized water to retain hotwell level as various vents and drains are routed to the drain tanks and inventory is lost from the cycle. A special section of tubes and baffles is used to allow the removal of dissolved oxygen from the makeup water before it is mixed in the hotwell.

1.2.5. Cooling Tower

The cooling tower receives heated water from the circulating water system and utilizes evaporative cooling as the water cascades down the fill to reduce the water temperature to near that of the ambient wet bulb.

1.2.5.1. Major Components:

- Multi-cell cooling tower structure
- Cooling fans, and drive system
- Water distribution system, including fill and drift control media
- Fire protection system
- Lightning protection system

1.2.5.2.System Description

One (1) multi-cell cooling tower will be installed at the Facility. The tower will be divided into single cells, each capable of being operated independently, by full-width partition walls constructed of fiberglass and extending from the bottom of the fill to the underside of the fan deck.

Cooling fans will be propeller type, directly connected to its motor through a totally enclosed, heavy-duty gear reducer and drive shaft. Fans, gear, shaft bearings, and motors will be mounted on a common galvanized steel baseplate. Fan motors will not be located in the fan stack or air plenum. The fans provide sufficient air flow through the fill sections to allow the necessary evaporation of water to cool the remaining water. After the air flows through the fill, it passes through a drift elimination section to reduce any water droplets in the warmed air leaving the tower.

The cooling tower structure will be built of fiberglass. A closed head dry pipe fire protection system will be provided for the tower, including stairways. The system will be the dry deluge type designed in accordance with National Fire Protection Association (NFPA) 214 and will have the approval of the owner's fire insurance underwriters.

A complete lightning protection system will be provided in accordance with applicable standards. A controlled blowdown system is used to control the concentration of dissolved solids in the circulating water of the tower basin. A tower bypass system is also included to return the warm water directly to the basin when freezing would occur in the fill sections.

1.3. Common Mechanical Systems

1.3.1. Fuel Gas Supply System

The fuel gas supply system will receive natural gas from the gas supplier's metering station. The system will regulate, filter and deliver natural gas to the CTG and CC CTGs.

1.3.1.1.Major Components:

The Fuel Gas Supply System includes the following major components:

- Multi-cyclone scrubber
- Tandem gas pressure reducing valve sets
- Fuel gas heaters
- Coalescing filters

1.3.1.2.System Description

Pipeline quality natural gas will be supplied via a 12 inch diameter steel transmission line at a pressure up to 1,000 psig at the interconnection point with a delivery pressure to the Plant of approximately 700 to 900 psig. The transmission line will run from the interconnection point for approximately 11 miles to the Plant site. The design of the transmission piping system will ensure that gas surges associated with a trip of one CTG or CC CTG will not affect continuous operation of CTG and CC CTG. Load control and metering will be monitored by Cheyenne Light's existing SCADA system.

One multi-cyclone scrubber will be installed to remove particulate and moisture from the gas prior to pressure regulation. The fuel gas drains tank receives blowdown from the multi-cyclone scrubber. Two tandem gas pressure reducing valve sets will be installed in parallel. Each tandem gas pressure reducing valve set includes one 50% self-contained pressure regulator and one (1) 50% monitor regulator to reduce gas pressure to within the limits required at the CTG and CC CTG inlet. A separate gas pressure reducing station will be installed downstream, with two (2) 50% trains, to provide fuel gas to the inlet air heater.

Two (2) 100% capacity fuel gas heaters will provide dew point heating to ensure dry gas enters the CTG and CC CTG while one coalescing filter per CTG unit will remove any other remaining particulates or liquids before entering the CTG units

1.3.2. Fire Protection and Detection System

The fire protection and detection system provides fire pumps, water storage, hydrants, fire extinguishers, manual pull stations, notification, fixed suppression systems, and independent fire detection systems to protect plant personnel, buildings, and equipment in the event of fire.

1.3.2.1.Major Components:

The fire protection and detection system include the following major components:

- Connection to the CBOPU municipal water system
- Firewater storage tank (a dedicated portion of the service water storage tank)
- Firewater pump package (skid mounted enclosure)
- Underground firewater loop piping, fire hydrants, valves, instrumentation, and accessories
- Sprinkler systems in various plant buildings, sized in accordance with NFPA requirements
- Fire detection and alarm system
- Hand-held fire extinguishers

1.3.2.2.System Description

The primary source of firewater for the Facility will be the CBOPU municipal water supply. As a secondary source, the Facility will include its own firewater storage and pumping capabilities.

The secondary firewater system consists of a stand-alone fire pump package which is Underwriters Laboratory (UL) listed. The fire pump package includes an electric-driven fire pump, a diesel engine-driven backup fire pump, and an electric-driven jockey pump.

The fire pump package will take suction from an adjacent treated/firewater storage tank. The tank will be sized to hold a sufficient quantity of water for the fire pump to operate at design capacity for two hours.

The firewater distribution system consists of a looped fire main that will extend to all fixed fire protection systems and yard fire hydrants. Fixed fire protection systems will be located at the cooling tower and in the administration building. Fire protection systems will be hydraulically designed and installed to the latest NFPA guidelines and meet the requirements of the authority having jurisdiction.

A detection and alarm system will be designed and installed in accordance with local, state and federal standards. An alarm panel which collects monitoring signals from throughout the Facility will be located within the control room, near the plant operator's workstation.

1.3.3. Water Systems

Several water and wastewater systems will be installed to meet the water and wastewater disposal needs of the Facility. The Facility will receive potable water from the CBOPU municipal water system, and the service water system will utilize wastewater effluent water from the CBOPU wastewater treatment plant. Plant wastewater and sanitary wastewater will be directed to the CBOPU treatment plant that is located adjacent to the Facility or will be discharged to Dry Creek through a Surface Water Discharge permit issued by the WDEQ.

1.3.3.1. Major Systems:

- Circulating water system
- Auxiliary cooling water system
- Service water system
- Evaporative cooling water system
- Demineralized water system
- Potable water system
- Wastewater system
- Sanitary waste system

1.3.3.2. Systems Descriptions

1.3.3.2.1. Circulating Water System

The circulating water system removes waste heat from the condenser. Circulating water is drawn from the cooling tower basin by the circulating water pumps, passed through the condenser's water boxes and tubes, and returned to the cooling tower. The circulating water system includes circulating water pumps and interconnecting piping, valves, instrumentation, and accessories. In addition, makeup water is supplied from the service/fire water tank, and blowdown is sent to the wastewater system. A chemical feed system will be installed to monitor and maintain the quality of the water and prevent corrosion or contamination within the circulating water system. The circulating water system will have three (3) chemical treatment systems to reduce alkalinity, to treat and prevent scale, and for controlling biological growth.

1.3.3.2.2. Auxiliary Cooling Water System

The auxiliary cooling water system removes waste heat from various equipment coolers, which are not cooled by other means. The auxiliary cooling water pumps also draws circulating water from the cooling tower basin and provides water to the steam turbine, its generator and auxiliary systems, and coolers associated with the boiler feed pumps and the vacuum pumps. The auxiliary cooling water system includes auxiliary cooling water pumps and interconnecting piping, valves, instrumentation, and accessories.

1.3.3.2.3. Service Water System

The service water system treats, stores and forwards potable water to the treated water system, demineralized water treatment, service water system and the potable water system. The service water system is comprised of a service water storage tank, service water forwarding pumps and interconnecting piping, valves and instrumentation. The Facility's service water system will receive potable water from the CBOPU municipal water system at a tie point that is approximately one (1) mile from the project site.

1.3.3.2.4. Demineralized Water System

The demineralized water system receives potable water directly from the CBOPU municipal water system, processes the water to remove minerals, stores it in a dedicated tank, and supplies the demineralized water to the water wash and compressor water injections systems for the CTG and CC CTGs, and condenser for steam cycle makeup. The demineralized water system is comprised of a demineralized water storage tank, backflow preventer, two (2) rental deionized water systems that include mixed bed units, which will be regenerated off-site, and two 100%-capacity demineralized water distribution pumps.

The demineralized water storage tank will be designed and fabricated in accordance with ANSI/American Water Works Association (AWWA) D100-84, Welded Steel Tanks for Water Storage or API 650. The tank will be constructed of carbon steel and the inside surface will be coated with epoxy. Demineralized water pumps will circulate water from the storage tank to the condenser for initial fill and makeup. The demineralized water pumps will also circulate makeup water to the CT water wash, and the compressor water injection system. The CTG and CC CTGs utilize the water wash system as a cleaning system, which allows the compressor section to be cleaned during full load operation or for an off-line soak washing. Demineralized water is also supplied to the sample panel for sample cooling. Compressor water injection is used for power augmentation when desired during normal operation.

1.3.3.2.5. Potable Water System

The potable water system supplies clean, potable water for lavatories, showers, toilets, and safety shower stations. The system will be designed in accordance with local regulations and standards. Safety showers/eyewash stations, a pressure tank and backflow preventers are the major components of the potable water system. The safety showers include one scald protection bleed valve and one flow switch. Backflow preventers will be installed to prevent possible contamination of the potable water system from other interconnected systems such as the demineralized water system

1.3.3.2.6. Wastewater System

The wastewater system will collect and treat wastewater from CTG and CC CTGs drains, STG, HRSG, steam cycle drains, CTG and CC CTGs wash water, evaporative cooler blowdown, cooling tower blowdown, several water treatment systems including the filtration, reverse osmosis, and demineralization units, air compressor condensate and equipment wash-down drains. The major components of the wastewater system include recovery sumps, sump pumps, drain tanks, water wash drains tanks, drain tank pumps, oil/water separator, and interconnecting piping and valves.

Wastewater, which may contain oil, will be collected in area drains and routed to the oil/water separator. After separation, waste oil is retained for off-site disposal and clear water is pumped to the wastewater sumps.

Spent wash water is collected in the wash drain tanks. The spent wash water contains detergent and could contain some oily residue from turbine washes. The water is pumped into a chemical waste removal truck for disposal.

Cooling tower and evaporative cooler blowdown will also be discharged to the wastewater sumps, from which it will be pumped to the CBOPU water treatment facility tie-point, located about 1 mile from the plant.

1.3.3.2.7. Sanitary Waste System

The sanitary waste system collects wastewater from toilets, showers, and lavatories within the facility. The system will gravity drain into the CBOPU treatment plant, adjacent to the facility and will be designed in accordance with local regulations and standards.

1.3.4. Heating, Ventilation, and Air Conditioning

Heating, ventilating, and air conditioning systems will be provided as required for all areas housing personnel and/or areas containing electrical equipment within the water treatment enclosure, Admin/Control building and workshop/warehouse building. Redundant HVAC will be provided for the control room.

1.3.5. Compressed Air Systems

The compressed air system supplies clean, dry air at the required pressure and capacity for pneumatic controls, instruments, valve operators, and nonessential air requirements and includes a compressed air package, compressed air receivers and distribution piping.

The distribution piping supplies dried, filtered, compressed air to plant equipment, and includes quick disconnect hose connections for service air uses. Self-contained backpressure regulator valves will be provided in lines supplying air for nonessential services to isolate air in the event that the main air header pressure drops below 85 psig.

1.3.6. Ammonia Storage System

One (1) 8,500 gallon aqueous ammonia storage tank will provide sufficient storage for the entire facility. The storage tank design and fabrication will be in accordance with ASME Code Section VIII, Div. 1. The tank will receive aqueous ammonia from trucks. Two (2) 100% aqueous ammonia forwarding pumps will be provided. The pumps will take suction from the storage tank and forward aqueous ammonia to the CC and CTG. The Facility will manage the ammonia system through an ammonia handling plan.

2. Electrical Systems

The principal electrical systems and equipment required for the Facility include the generator system, generator step-up (GSU) transformers, an auxiliary power supply system, diesel generator to provide backup electric power and a high voltage interconnection. The Facility will interconnect to Cheyenne

Light's 115 kV transmission system through a proposed 115 kV substation located at the project site. The proposed 115 kV substation will be incorporated into the existing Cheyenne Light Archer to Skyline 115 kV transmission line through a proposed approximate two (2) mile double circuit transmission line. The major components of the double circuit transmission line will be conductors, shield wires, insulators and steel poles. The major components of the proposed 115 kV substation will include circuit breakers, air break switches and associated structures.

In general, the electrical systems and equipment described in this section will, as a minimum, meet the requirements of NFPA 70 (National Electric Code), ANSI, Institute of Electrical and Electronics Engineers (IEEE), National Electrical Manufacturers Association (NEMA), and the National Electrical Safety Code (NESC).

2.1. Generator System

The generator system transfers electrical energy from the STG, CTG and CC CTGs to the GSU transformers and plant auxiliary power supply. The system includes the generator breakers, which are used to connect the generators to the electrical system, the GSU transformers, current limiting reactors, and non-segregated bus duct that carries the electrical energy to the GSU transformers.

2.1.1. Major Components:

The generator system includes the following major components:

- Non-segregated bus duct
- Generator circuit breakers
- Current-limiting reactors

2.1.2. System Description:

The non-segregated bus duct transfers power from the CTG, CC CTGs and STG to the GSU transformers. The non-segregated bus will include termination compartments as necessary to interface with the generator breaker, and transformer terminals. The non-segregated bus will be sized to meet the voltage, current, and short circuit conditions of the installation. An interface box, containing the necessary bus work and flexible links, will be necessary to connect the bus ducts to the transformer secondary.

The generator circuit breakers will be SF_6 breakers and designed, manufactured, and tested in accordance with the latest standards of ANSI, particularly ANSI C37.013, and NEMA. The generator circuit breaker will be 15kV type SF6, 8000A, 80KA RMS short circuit and suitable for the bus connections. Synchronizing potential transformers (PTs) will be provided on the GSU side of the breaker.

Current limiting reactors will be sized to reduce the available fault current to an acceptable level. The reactors are necessary due to the fact that two generators will be connected to one GSU transformer secondary.

2.2. GSU Transformers

The GSU transformer will step up the output voltage of the generators from 13.8 kV to a level which is compatible with the substation voltage. Copper windings will be provided and the impedance value will be selected to be compatible with utility interconnection studies. The GSU transformers will be 3-phase, 60 hertz, two-winding, mineral oil-filled, outdoor units. The transformer's high voltage windings will be connected in a solidly-grounded wye configuration. The transformer's high voltage terminals will have surge arresters and will be mounted on top of the transformer tank. The transformer's low voltage winding will be connected in a delta configuration.

The transformers will be equipped with standard accessories according to ANSI C57.12. In addition to the standard accessories, the transformers will be equipped with a fault pressure relay. Two sources of 480 volt, 3-phase auxiliary power will be supplied to the transformers. An automatic transfer switch will transfer from the normal source to the alternate source of power should the normal source fail.

2.3. Auxiliary Power Supply System

The auxiliary power supply system provides electrical power to the CTG, CC CTGs, STG and the balance of plant auxiliary loads.

2.3.1. Major Components:

The auxiliary power supply system includes the following major components:

- Unit auxiliary transformers (UAT) –one per CTG and CC CTG
- Station service transformers (SST)– one per CTG and CC CTG
- Cooling tower 480V secondary unit substation transformer
- Medium voltage (4.16kV) switchgear – 1 lineup per CTG and CC CTG
- Low voltage (480V) switchgear – 1 lineup per CTG and CC CTG
- Low voltage motor control centers (MCC) and panelboards

2.3.2. System Description:

Each UAT will step down the generator terminal voltage from 13.8 kV to 4.16 kV. The transformers will provide normal power to all of the plant auxiliary electric loads through the plant's 4.16 kV switchgear.

Each UAT will be a 3-phase, 60 hertz, two-winding, mineral oil-filled, outdoor unit. The transformer high voltage windings will be solidly connected to the generator terminals and the GSU transformer low voltage terminals and will be connected in delta configuration. The transformer low voltage winding will be connected in a wye configuration with the neutral grounded through a resistor. The transformer will be equipped with standard accessories according to ANSI C57.12. In addition to the standard accessories, the transformer will be equipped with a fault pressure relays.

2.4. Diesel Generator

A diesel generator will provide backup electric power to serve critical loads and to charge batteries for the uninterruptible power supply system, in the event that power supply to the Facility is lost. The unit will be briefly operated on a monthly basis to ensure readiness.

2.4.1. Major Components:

The diesel generator includes the following major components:

- Skid mounted 500kW diesel engine with generator
- Fuel storage tank
- Controls

2.4.2. System Description:

The diesel generator will be capable of automatic start, and synchronization in the event of a power failure. The generator will also be provided with remote start/stop, test and synchronize capabilities.

2.5. High Voltage Generator Interconnection

The Plant will interconnect to Cheyenne Light's 115 kV transmission system at a new 115 kV substation located at the project site

2.6. 115 kV Substation

The 115kV substation will be designed and constructed to initially accommodate two 115 kV transmission lines and two (2) 115 13.8kV GSU transformers.

2.6.1. Major Components

- Circuit breakers
- Air break switches
- Associated structures – aluminum buses, line terminating structures, control building

2.6.2. System Description

The substation will include 115kV, SF6 gas circuit breakers, each with a continuous current rating of 2,000 amperes. Each breaker will have twelve 2000:5 ampere, multi-ratio class 800 current transformers to be used for the protective relaying and metering systems.

The substation will contain 115kV manual operated air break switches, each with a continuous current rating of not less than 2,000 amperes. Each switch will have light gray post insulators with the mechanical strength to meet the NESC strength requirements. The switches will be mounted on galvanized steel switch stands and grounded to operator switch platforms, meeting single point grounding requirements for operator safety.

Aluminum buses will have a minimum continuous current rating of 2,000 amperes and will be supported on galvanized steel bus stands with the horizontal spacing and ground clearance meeting the requirements of the latest edition of the NESC.

The 115kV transmission line termination structures will be galvanized steel "A" frame structures meeting the loading requirements of the latest edition of the NESC.

The station control building will be a pre-manufactured building containing the equipment necessary to operate the station consisting of lighting, heating and air conditioning systems, a 125 volt battery system, relay panels, metering panels, control panels, AC/DC panels and associated cable trays, conduit and wire.

The station yard will be graded for proper drainage, compacted to at least 90 percent and graveled. The yard perimeter will be fenced with a seven-foot high chain link fence, with a one-foot barbed wire top rail.

The substation site will be sized and arranged to allow for future expansion. Future expansion may require the installation of additional 115kV circuit breakers, air break switches, and associated substation structures, equipment and facilities.

2.7. 115 kV Transmission Line

A proposed 115kV double circuit transmission line segment will incorporate the proposed 115 kV substation into Cheyenne Light's existing Archer to Skyline 115 kV transmission line. Exhibit EE-2 attached to the testimony of Eric Egge shows a potential route of the double circuit transmission line segment.

2.7.1. Major Components

- Steel poles
- 795 ACSR 26/7 standing conductor
- Galvanized steel shield wire
- Insulators

2.7.2. System Description

The proposed double circuit transmission line segment will utilize single, self-supporting steel poles either direct embedded or on foundations. Strength of the structures will meet or exceed requirements set forth in the latest edition of the NESC.

The conductor will be a vertical arrangement, 795 ACSR 24/7 stranding, code name Tern. Each conductor will weigh 1.094 pounds per foot, with ultimate breaking strength of 31,500 pounds. The shield wires will consist of one 3/8 inch seven strand extra high strength (EHS) galvanized steel and one 48 fiber optical shield wire (OPGW). The shield wire will be 0.360 inches in diameter and will weigh 0.273 pounds per foot, with ultimate breaking strength of 15,400 pounds. The OPGW shield wire will be 0.443 inches in diameter and will weigh 0.292 pounds per foot, with ultimate breaking strength of 15,919 pounds.

The insulator that supports the conductor on tangent structures will consist of single suspension strings with seven (7) units per phase and 20,000 pound rated strength. The angle and dead-end assemblies will consist of strings of ten (10) units per phase and 20,000 pound rated strength. Design ground clearance will be at least 26 feet.

3. Instrumentation And Control Systems

The principal instrumentation and control systems required for the proposed Plant include the plant control system and the continuous emissions monitoring system.

3.1. Plant Control System

The CC and common equipment will be monitored and controlled in the main control room by a distributed control system, (DCS). Separate programmable logic controller (PLC) systems may be utilized for subsystems such as the water treatment system, fire pump controller, and continuous emissions monitoring system (CEMS). Equipment packages such as chemical injection, air removal and ammonia vaporization system may be controlled and monitored by the DCS (to be determined during detail design).

The CTG will be monitored and controlled by the turbine manufacturer's control systems.

Auxiliaries such as sump pumps that need not be in continuous operation for electric power production shall be monitored, controlled, and protected locally, with limited control room monitoring and control.

3.2. Continuous Emissions Monitoring System

The continuous emissions monitoring system (CEMS) measures and records the emissions from each of the exhaust stacks as required by the U.S. Environmental Protection Agency (EPA) Code of Federal Regulations and the WDEQ. Each CEMS will consist of one (1) set of continuous emissions monitors which will monitor CTG and CC flue gas constituents.

Each CEMS will include a continuous duty remote type analyzer subsystem with an extractive probe sampling system for each CTG and CC unit and a common data collection system including, a data acquisition and handling system (DAHS), shelter and analyzer equipment. The CEMS also includes analyzers, sample extraction equipment, data acquisition system, controller (if required), software, controls, a power supply transformer, distribution panel, an interface terminal box and other system specific accessories. The design will meet performance specifications and regulatory requirements.

All analyzers and DAHS will be powered via contractor-supplied UPS. The continuous emissions monitors will be capable of multi-range operation, if necessary for compliance with 40 CFR Part 75, Appendix A and EDR Version 2.1 or latest version at the time of installation.

4. Civil Works

Site development and grading will be completed to ensure that stormwater drainage is managed appropriately, sufficient surfacing is completed to provide employee parking and access to generation facilities and buildings and fencing installed for site security. A construction storm water permit will be secured from the WDEQ which will require the development of a Storm Water Pollution Prevention Plan.

4.1. Site Development and Grading

The initial site development work will include clearing and grubbing the site, disposing of non-hazardous waste, stripping and stockpiling topsoil, the installation and maintenance of construction parking and construction laydown areas and the construction of temporary and permanent drainage facilities using accepted best management practices (BMP) for erosion and sediment control.

Facility grading work will include shaping the natural grade as required to accommodate both construction facilities and permanent facility equipment. Grading will be carried out in a manner that will minimize earthwork while obtaining proper cross section, longitudinal slopes, and curvature for roads, raising grades as necessary to eliminate flooding from external water courses due to the 100-year rainfall and constructing stable, erosion-resistant earthen side slopes. The 100-year runoff from up hill drainage areas will be diverted around the Facility and returned to the natural drainage course in a manner acceptable to the permitting agency.

Drainage and storm water will be managed using a clean storm drain sewer and ditch system and oil-contaminated runoff sewer system (see wastewater system).

A looped facility road will be provided around the power block area and interior facility roads will be provided where access is required to equipment, pump structures, or entrances to buildings or enclosures. All open areas will be covered with crushed rock to control dust.

Temporary security fencing will be provided around the entire property line with appropriate gates to accommodate construction activities. Permanent security fencing will be installed around the perimeter of the new facility. The plant entrance gate will be a motor operated gate, which will be remotely controlled from the control room or by an electronic keypad or access card locally. All other gates will be manually operated.

5. Structural Works

5.1. Earthwork, Excavation and Fill

A geotechnical investigation will be performed at the project site. The investigation will determine the suitability of site soils for use as compacted fill, and their ability to achieve the desired compaction requirements with the proper moisture treatment.

Excavations for the CTG and CC as well as gas pipeline, water and wastewater trenches will be carried out and supported in such a manner as to prevent flooding or ponding of water, damage or interference to other existing structures, utility services or stored equipment/materials. Excavations for foundations will be sealed with a concrete mud mat or seal slab, if required, as soon as possible after being excavated and inspected. The gas pipeline trench will comply with Cheyenne Light's construction standards and any waterline trenching, water and wastewater, will comply with codes adopted by the City of Cheyenne.

Fill materials will be suitable for the intended purpose and will not include materials hazardous to health, material susceptible to attack by ground or groundwater chemicals, material susceptible to swelling or shrinkage under changes in moisture content, highly organic or chemically contaminated materials or any other unacceptable materials.

Compaction of fill materials will be carried out as soon as practicable after deposition of fill materials. Fill will be compacted to the densities appropriate to the design requirements, fill type and depth of layers.

5.2. Foundations

Geotechnical exploration, steel pile testing, and analysis information will be used to determine the most suitable foundation system. Foundation analysis for major equipment will include the evaluation of total and differential settlement. Dynamic foundation analysis and design will be performed for the turbine generators when recommended by the equipment manufacturer. Foundations will meet all manufacturer requirements. Additionally, foundations for rotating equipment will not impart unreasonable vibration levels, consistent with normal utility industry practice, to surrounding foundations and equipment.

Above ground tanks, equipment skids, pumps and supports will be installed on raised slabs or pads for corrosion protection. All foundation floor elevations will be above the 100 year flood plain and the floor elevation of buildings and the top of foundations for major outdoor equipment will be a minimum of six (6) inches above the high point of finished grade elevation. Oil-filled equipment foundations will have an integral reinforced concrete spill containment area.

5.3. Steel Work

Steel design will be in accordance with the latest edition of the American Institute of Steel Construction (AISC) design manual, allowable stress design. The selected contractor will utilize a system to validate type and grade of high strength bolts by sampling and metallurgical testing. All hoist and monorail support beams will be clearly marked with their rated capacity.

5.4. Buildings

Buildings will be constructed to provide the space needed to house the plant's personnel as well as electrical and auxiliary equipment. It is expected that a control/administration building, a warehouse/workshop building and a water treatment building will be required.

Subsection 204(d). List the rates, if any, proposed to be charged for the service that will be rendered because of the proposed construction.

Cheyenne Light Forecasted Revenue Requirement

Cheyenne Light used a standard declining cost curve rates model to determine the revenue requirement for the Facility. These costs include economy purchase power in lieu of natural gas burned in the CTG and CC. In addition, the revenue requirement is reduced by removing the capacity associated with the PPA for CT2, a natural gas-fired combustion turbine that will expire in August 2014.

The table below lists the estimated revenue requirements for the first six (6) years of operation of the Facility. Please see Exhibit APP-1 for the extended revenue requirements forecast.

Cheyenne Light Forecasted Revenue Requirements

Year	2014	2015	2016	2017	2018	2019
Revenue Requirements	$14,857,986	$26,259,138	$25,456,777	$26,983,422	$27,523,086	$24,257,984

The revenue requirements are provided for illustrative purposes only. A rate application will be filed with the Commission prior to inclusion of the capital costs associated with the Facility in customer rates.

Black Hills Power Forecasted Revenue Requirement

Black Hills Power used a standard declining cost curve rates model to determine the revenue requirement for the Facility. These costs include economy purchase power in lieu of natural gas burned in the CCs.

The table below lists the estimated revenue requirements for the first six (6) years of operation of the Facility. Please see Exhibit APP-1 for the extended revenue requirements forecast.

Black Hills Power Forecasted Revenue Requirements

Year	2014	2015	2016	2017	2018	2019
Revenue Requirements	$10,975,609	$19,343,276	$21,478,587	$20,153,556	$20,299,815	$20,570,866

The revenue requirements are provided for illustrative purposes only. A rate application will be filed with the Commission prior to inclusion of the capital costs associated with the Facility in customer rates.

Subsection 204(e). State the estimated total cost of the proposed construction.

The current total estimated cost of the Facility is $237 million. See Exhibit ML – 1. This cost estimate is based on the design basis document that was developed to identify all the required systems and major equipment of the facility as listed in Subsection 204(c). In addition, vendor proposals, current equivalent project costs and known site development cost impacts were all taken into consideration in developing this cost estimate.

Cheyenne Light's total estimated portion of the cost of the Facility is $145.3 million, but Cheyenne Light will recoup a portion of that amount from Black Hills Power on a revenue requirement cost recovery-type basis for an effective capital cost to Cheyenne Light of $135.7 million. Black Hills Power's total estimated portion of the cost of the Facility is $91.7 million but will pay Cheyenne Light over time its 42% of the capital costs related to the Gas Pipeline and Transmission Interconnection. Cost allocations are more fully described below and in Exhibit ML – 1.

The Facility consists of five general components: 1) the CTG; 2) the CC; 3) the Gas Pipeline; 4) the Transmission Interconnection; and 5) the Common Capital Assets.

The following is general information regarding each of the five general components of the Facility, together with the ownership and the cost of each:

1. **CTG** -- The combustion turbine generator with a net output of 37 MW, which will be wholly-owned by Cheyenne Light. The estimated cost of the CTG is $49.0 million.
2. **CC** -- The combined cycle unit with a net output of 95 MW, which will be owned by Cheyenne Light (undivided 42% ownership for 40 MW) and BHP (undivided 58% ownership for 55 MW). The parties will negotiate an agreement that will set forth the determination and allocation of operating and maintenance expenses and future capital costs regarding the CC. The estimated cost of the CC is $139.8 million.
3. **Gas Pipeline** -- The gas pipeline will deliver natural gas from the interstate pipeline to the Facility, a distance of approximately 11 miles. The gas pipeline will be owned and paid for by Cheyenne Light. Cheyenne Light and Black Hills Power will negotiate a contract whereby Black Hills Power will pay to Cheyenne Light approximately 42% of Cheyenne Light's capital costs

and annual operating expenses on a revenue requirement cost recovery-type basis. The estimated cost of the gas pipeline is $15.9 million.

4. **Transmission Interconnection** – The transmission interconnection line will run from the substation on the Facility land to the 115 kV transmission line of Cheyenne Light, a distance of approximately 2 miles. The transmission interconnection will be owned by Cheyenne Light. Black Hills Power will pay Cheyenne Light approximately 42% of Cheyenne Light's capital costs and annual operating expenses on a revenue requirement cost recovery-type basis. The estimated cost of the Transmission Interconnection is $7.0 million.
5. **Common Capital Assets** – The Common Capital Assets include all of those assets of the Facility that do not fall within any of the above four categories, but that are used by or indirectly benefit the CTG and the CC. For example, one of the Common Capital Assets is the administration building, which will serve both the CTG and CC generating units. The common capital assets will be owned 58% by Cheyenne Light and 42% by Black Hills Power. The percentage of common capital assets ownership is based on each entity's net MW compared to total net MW of the Facility. The parties will negotiate an agreement that will set forth the determination and allocation of operating and maintenance expenses and future capital costs regarding the Common Capital Assets. The estimated cost of the Common Capital Assets is $25.2 million.

Subsection 204(f). State the manner by which the proposed construction will be financed.

It is anticipated that the construction costs regarding the Facility will be financed in a manner similar to other major projects through the use of internally generated funds and short-term borrowings from the Black Hills Corporation utility money pool.

Subsection 204 (g). State the financial condition of the applicant.

The financial integrity of both Cheyenne Light and Black Hills Power is sound. Cheyenne Light files quarterly and annual income statement, balance sheet and cash flow information with the Federal Energy Regulatory Commission (FERC). Applicable portions of Cheyenne Light's 2010 annual FERC filings which include the financial condition information as required in Section 202(a) are set forth in Exhibit BGI-1 attached to the testimony of Brian Iverson.

Black Hills Power files quarterly and annual income statement, balance sheet and cash flow information with FERC. These documents are set forth in Exhibit BGI-2 attached to the testimony of Brian Iverson. The senior secured debt of Black Hills Power is currently rated A3 by Moody's Investors Service, BBB+ by Standard & Poor's Financial Services, and A- by Fitch.

Subsection 204(h). State the estimated annual operating revenues and expenses that are expected to accrue from the proposed construction.

The table below shows the first six years estimated revenues and associated expenses for the portion of the proposed Facility owned by Cheyenne Light. The operating revenues include an adjustment for an annual fee that Cheyenne Light will receive from Black Hills Power for 42% of the capital costs and operating expenses on a revenue requirements basis related to the Gas Pipeline and Transmission Interconnection. Please see Exhibit APP-1 for the extended revenue and expense forecasts.

Cheyenne Light's Forecasted Operating Revenues and Expenses

Year	2014	2015	2016	2017	2018	2019
Operating Revenues	$14,857,986	$26,259,138	$25,456,777	$26,983,422	$27,523,086	$24,257,984
Operating Expenses	$5,362,174	$9,214,556	$9,282,883	$9,354,392	$9,429,078	$9,506,934

The table below shows the first six years estimated revenues and associated expenses for the portion of the proposed Facility owned by Black Hills Power. The operating expenses include an annual fee paid to Cheyenne Light by Black Hills Power for 42% of the capital costs and operating expenses on a revenue requirements basis related to the Gas Pipeline and Transmission Interconnection. Please see Exhibit APP-1 for the extended revenue and expense forecasts.

Black Hills Power's Forecasted Operating Revenues and Expenses

Year	2014	2015	2016	2017	2018	2019
Operating Revenues	$10,975,609	$19,343,276	$21,478,587	$20,153,556	$20,299,815	$20,570,866
Operating Expenses	$4,856,771	$8,385,620	$8,432,138	$8,481,896	$8,534,890	$8,591,115

Subsection 204(i). State the estimated starting and completion date of the proposed construction.

Construction activities will commence in the fourth quarter 2012 with the construction phase lasting approximately 18 months. It is expected that the Facility will begin commercial operation in the summer of 2014. During the summer of 2013, it is anticipated that construction activities will consist of equipment mobilization; preliminary site work including clearing, leveling, and grading work; excavation; substructures and piping; and foundation work including erection of foundations and steel structures. Major construction activities will commence in third quarter 2013, including mechanical and electrical work, and construction of combustion turbine generators, air quality control system and major auxiliary equipment.

This estimated schedule is based on receipt of an approved CPCN and air permit by fourth quarter 2012 and recent past experience associated with construction of similar facilities.

Subsection 205(a). The proposed site by an appropriate description of the involved properties and the county or counties in which the major utility facility will be located and where possible a metes and bounds description; a description of the route of line or lines in the project and the number of route miles located in each county; a description of the various types of country in or through which the facility will be constructed.

The Facility will be located in Section 1, Township 13 North, Range 66 West, of the 6th Principal Meridian, Laramie County, Wyoming. The legal description for the project site is attached to Mark Lux's testimony as Exhibit ML-3.

The Gas Pipeline will be placed in an easement that will run in a northerly direction from an interconnection point with an interstate pipeline for approximately 11 miles to the Plant site. The exact route of the Gas Pipeline will depend on the Applicant's ability to acquire easements from property owners, selection of an interstate gas pipeline interconnection point and assessment of topography between the interconnection and the Plant. Therefore, the Applicants requests that it be allowed to build the Gas Pipeline within the corridor identified on Exhibit APP-3. The entire length of the pipeline will likely be located in Laramie County. The route selected will likely be the most direct route from the interstate gas pipeline interconnect to the Plant and have the least possible impact on property owners. The majority of the land the Gas Pipeline line will cross is open rangeland with an agricultural zoning designation.

The proposed Transmission Interconnection segment will be placed in a new 90 foot easement that will run in a westerly direction from where Cheyenne Light's existing Archer to Skyline 115 kV turns north. The proposed Transmission Interconnection segment will cross over three existing 115 kV transmission lines before turning west and paralleling the existing WAPA lines to the project site. The exact route of the proposed Transmission Interconnection segment will depend on Cheyenne Light's ability to acquire easements from property owners.

Subsection 205(b). A brief report on the surrounding scenic, historical, archeological and recreational locations, natural resources, plants and animal life, land reclamation, possible safety hazards and plan for protecting the environment.

1. Project Site

The project site is located within the incorporated boundaries of the City of Cheyenne, approximately three miles east of Cheyenne, Wyoming. The project site is a privately-owned undeveloped parcel of approximately 250 acres. The parcel is characterized by gently rolling hills ranging from 5,900 to 6,000 feet above sea level. The parcel is bordered to the east by the Dry Creek Water Reclamation Facility, to the north by a transmission line, to the south by the Burlington Northern railroad, and to the west by an undeveloped property.

The site is grassland, and with the exception of a few two-track roads and fences, appears undisturbed (Photos 1 and 2). The observed current land use is grazing. Stormwater runoff ditches are present in the southwestern corner of the parcel, and an irrigation ditch is located in the southeastern corner.

Photo 1 – View from a knoll in the center of the parcel, looking southeast

Photo 2 – View from a knoll in the center of the parcel, looking west

A literature review was conducted through the Wyoming Cultural Resource Information System (WYCRO) database, which is an online database containing records of known archaeological, historic, and architectural sites as well as information on cultural resource surveys conducted within the state. The database is searched by township, range, and section returning results of sites or projects within each section. Further refinement is achieved by examining quarter sections or information contained within the records returned through the query. Based on the available literature, the project site has not been previously surveyed for cultural resources and there are no known cultural resources within the project site. There have been 10 cultural resource surveys conducted within one mile of the project site between 1981 and 2009.

The literature review identified five cultural resource sites within one mile of the project site. Although there are no known cultural resources within the project site, one site, the Archer-Cheyenne Transmission Line (LA1400) is adjacent to the northern boundary of the project site. This site is considered not eligible for listing on the National Register of Historic Places (NRHP). The remaining known sites are located far enough outside of the project site that they will not be affected by project activities. It should be noted, however, that the project site was at one time a part of the Hereford Ranch, a property that is listed on the NRHP. There are no structures or known features associated with the Hereford Ranch on the project site; this area was historically agricultural fields or rangeland.

The Facility will be on private land and compliance with Section 106 of the National Historic Preservation Act may be required based on air permit and the industrial siting permit requirements. However, federal permitting may trigger a Section 106 consultation with the State Historic Preservation Office (SHPO). Likewise, should the project be subject to review under Wyoming's Industrial Siting Act (ISA), the SHPO would become a commenting state agency during the ISA process. Should this occur, it is likely the SHPO would require a pedestrian survey to identify cultural resource sites and determine the effects the project may have on them. Impacts to cultural resources could be avoided by project design or through mitigation developed in consultation with the SHPO.

Because of the lack of significant cultural resource studies conducted in the area, it is impossible to determine if this project will have an effect on cultural resources. Based on the projects' location in an area of numerous transportation corridors and the proximity and association with other known historic resources, there is a high probability of finding additional cultural resources within the project site. However, without a project specific pedestrian inventory for cultural resources there is no way to determine the effects this project may have on cultural resources.

The project site presents a uniform upland grassland habitat for wildlife; no special or unique habitats are present. Given the project site's location and size, use by big game is likely limited to transient, occasional use; therefore, impacts are expected to be minimal. The site is not suitable habitat for sage-grouse (Centrocercus spp.), and is outside of identified sage-grouse core areas. Several common avian species were observed on site, and although project development may displace these avian species, impacts are expected to be minimal.

A raptor nest in a live cottonwood was observed approximately 1,200 feet south of the parcel along Crow Creek. Although a red-tailed hawk (Buteo jamaicensis) was observed in the area, it could not be associated with the nest, nor could the activity status of the nest be determined. Given the surrounding land uses (e.g., railroad, wastewater treatment plant, Interstate 80), development of the project site is not expected to cause direct impacts to nesting raptors. Indirect effects of the project on raptors would be the loss of foraging habitat.

There are no wetlands within the project site. Irrigation ditches along the southern boundary may be jurisdictional waters of the U.S., and even though no water will be discharged from the Facility, impacts to those ditches could require Clean Water Act permitting in consultation with the U.S. Army Corps of Engineers. Impacts to potentially jurisdictional waters of the U.S. could be avoided or minimized through project design. Impacts permitted by the U.S. Army Corps of Engineers could contain mitigation, if appropriate.

There are no national parks or state parks within twenty miles of the project site (National Parks Service, 2011). The nearest park, United Nations Park, and the nearest recreation facility, KOA Campground, are both located over one mile away from the project site.

A query of the WDEQ, Land Quality Division, shows that as of March 31, 2011 in the Cheyenne area, 33 sites are identified as having unresolved contamination issues (Wyoming DEQ, 2011). None of the sites identified are located within one mile of the project site boundaries. According to a query of the U.S. Environmental Protection Agency, the nearest Superfund site is located over 4.75 miles away (EPA, 2011).

Since the project site is undeveloped, the safety hazards associated with demolition of structures, such as asbestos or lead-based paints, will not be an issue. During operations, solid waste will be hauled to an off-site landfill by a private contractor. A telecom buried cable and a City of Cheyenne sewer pipe cross the project site (Environmental Technology and Training, 2005). During construction, the contractor will locate all underground and overhead utilities in accordance with generally accepted construction practices. To ensure public health and safety, Black Hills will obtain a National Pollutant Discharge Elimination System (NPDES) storm water construction permit. The Facility will also obtain an Industrial Wastewater Discharge permit from the City of Cheyenne to discharge wastewater to the wastewater treatment plant or an NPDES Surface Water Discharge permit with WDEQ. The City of Cheyenne has a NPDES permit with the State of Wyoming to ensure compliance with discharges to the water of the State. Air quality will be protected through the installation of Best Available Control Technology (BACT) as required by the WDEQ for criteria pollutants and the EPA for greenhouse gas (GHG) pollutants.

The Applicants will assume responsibility for reclaiming areas adjacent to the project site that are disturbed during construction. The Facility will be decommissioned at the end of its useful life and the land reclaimed, if appropriate.

2. Proposed Pipeline Corridor

The western and northern boundaries of the proposed pipeline corridor area are located approximately one mile east and one mile south of Cheyenne, Wyoming, respectively. The proposed corridor is approximately three miles wide east to west, and approximately nine miles long north to south. The northeastern corner of the pipeline corridor is adjacent to the western boundary of the project site. The exact route the pipeline would follow within the proposed corridor is not precisely known at this time. The land ownership within the proposed corridor is a mix of private, State and Federal land. The land within the corridor is characterized by gently rolling hills ranging from 5,900 to 6,200 feet above sea level. The corridor is bounded to the east and west by a mix of private, State and Federal lands, by the Wyoming/Colorado border to the south, and I-80 to the north.

The land within the corridor is predominantly grassland, with a reservoir and a quarry evident to the north. Land use within the corridor appears to be largely undeveloped and undisturbed, with some scattered agricultural activities and evidence of one residential development, all separated by County and local roads. No site visit was conducted in the preparation of this technical memo therefore no site photos are available. A cursory review of readily available online geospatial images of the corridor was conducted, primarily on Google Earth.

A literature review for the identification of known cultural resources was conducted through the Wyoming Cultural Resource Information System WYCRO database, which is an online database containing records of known archaeological, historic, and architectural sites as well as information on cultural resource surveys conducted within the state. The database is searched by township, range, and section returning results of sites or projects within each section. Further refinement is achieved by examining quarter sections or information contained within the records returned through the query. Given the size of the pipeline corridor examined, no buffer was included in the literature review.
The corridor searched included: Township 12 North, Range 66 West, and all of Sections 1, 2, 3, 10, 11, 12, 13, 14, and 15; Township 13 North, Range 66 West, and all of Sections 1, 2, 11, 12, 13, 14, 22, 23, 24, 25, 26, 27, 34, 35, and 36.

Based on the available literature, most of this proposed pipeline corridor has not been previously surveyed for cultural resources. Six surveys have taken place within the proposed pipeline corridor. Most of these are linear surveys with two small block surveys that covered less than 200 acres.
The literature review identified ten cultural resource sites within pipeline corridor. Six of the ten sites are prehistoric occupation sites consisting of rock rings, hearths, and artifact scatters (LA459, LA558, LA559, LA606, LA607, and LA608). All but one of these prehistoric sites have been recommended Not Eligible for listing on the National Register of Historic Places (NRHP). Site LA459 remains unevaluated pending further research and possibly testing to determine eligibility for listing on the NRHP. The remaining four sites include a historic can scatter (LA82), a historic transmission line (LA1400), a historic building (LA1406), and a historic railroad (LA3228). The historic building and the railroad are both significant resources that have been recommended as eligible for listing on the NRHP.

Compliance with Section 106 of the National Historic Preservation Act will be required due to the presence of federal lands. Likewise, should the project be subject to review under Wyoming's Industrial Siting Act (ISA), the SHPO would become a commenting state agency during the ISA process. It is likely the SHPO would require a pedestrian survey of a defined pipeline corridor to identify cultural resource sites and determine the effects the project may have on them. Impacts to cultural resources could be avoided by project design or through mitigation developed in consultation with the SHPO.

Because of the lack of significant cultural resource studies conducted in the area, it is impossible to determine if this project will have an effect on cultural resources. Based on the projects' location in an area of numerous transportation corridors and the proximity and association with other known prehistoric and historic resources, there is a high probability of finding additional cultural resources within the corridor. However, without a corridor specific pedestrian inventory for cultural resources there is no way to determine the effects this Facility may have on cultural resources. Wyoming Gap Analysis Program (GAP) land cover data of the area indicates that the pipeline corridor consists primarily of shortgrass prairie, agricultural, and developed areas (USGS 2007), as shown on Figure 4. The far northern portion of the pipeline corridor is primarily industrial with a riparian corridor running generally west to east. The Wyoming Hereford Ranch Reservoir and the Crow Creek riparian corridor are also found in the northern end of the pipeline corridor. The large majority of vegetation south of the reservoir is shortgrass prairie. Shortgrass prairie vegetation in the area is most likely grazed by cattle. A section of agricultural lands is located about 4 miles south of the reservoir.

Several U.S. Geological Survey National Hydrology Dataset water courses are mapped in the proposed pipeline corridor area. Irrigation ditches are also likely to be found in the area. Impacts to waterways and ditches could require Clean Water Act permitting in consultation with the U.S. Army Corps of Engineers. Impacts to potentially jurisdictional waters of the U.S. could be avoided or minimized through project design. Impacts permitted by the U.S. Army Corps of Engineers could contain mitigation, if appropriate.

Based on the habitat available in the area, it is likely migratory birds such as horned lark (Eremophila alpestris), meadowlarks (Sturna spp.), and kingbirds (Tyrannus spp.) would use the pipeline corridor. Raptors including red-tailed hawks (Buteo jamaicensis) and Swainson's hawks (Buteo swainsoni) may also be found foraging and nesting in the area. The site is outside of identified sage-grouse (Centrocercus spp.) core areas (University of Wyoming 2011). Big game species such as pronghorn (Antilocapra americana) may be found in the shortgrass prairie, and mule deer (Odocoileus hemionus) may utilize the riparian corridor or agricultural areas. Due to proximity of the pipeline corridor to urban and developed areas and because similar shortgrass prairie habitat is available adjacent to the corridor, it is unlikely unique habitat is found on site.

There are no national parks or state parks within twenty miles of the pipeline corridor (National Parks Service, 2011). The nearest park or recreation facility, United Nations Park and the KOA Campground, are both located over one mile away from the corridor area.

A query of the Wyoming Department of Environmental Quality, Solid and Hazardous Waste Division, shows that as of the most recent report (dated March 31, 2011), in the city of Cheyenne, 33 sites are identified as having unresolved contaminated issues (Wyoming DEQ, 2011). None of the sites identified are located within one mile of the corridor boundaries. According to a query of the U.S. Environmental Protection Agency, the nearest Superfund site is located over 4.75 miles away (EPA, 2011).

Since the majority of the land area within the proposed corridor is undeveloped, the safety hazards associated with demolition of structures, such as asbestos or lead-based paints, will likely not be an issue. During construction, the contractor will locate all underground and overhead utilities to prevent interference with utilities. To ensure public health and safety, the Applicants will obtain an NPDES permit and will adhere to all requirements of this permit to ensure wastewater discharges are properly treated prior to entering a receiving water body. Air quality will be protected through the Best Available Control Technology as required by the Department of Environmental Quality.

The Applicants will assume responsibility for reclaiming any areas adjacent to the pipeline that may be disturbed during construction. Where appropriate, the pipeline will be decommissioned at the end of its useful life and the land reclaimed, if appropriate

Subsection 205(c) Land, mineral and water requirements for the major utility facility, the status of the acquisition of land, or rights-of-way or of minerals and water for the project, the sources or locations thereof, and the proposed method of transportation and utilization.

The proposed Facility will be located on up to 250 acres within Section 1, Township 13 North, Range 66 West, of the 6^{th} Principal Meridian, Laramie County, Wyoming.

The proposed site is owned by B and L Land Company. On July 15, 2011 an affiliate of Black Hills Power and Cheyenne Light entered into a written option to purchase the land for the proposed site.

The water balance figure attached to Mark Lux's testimony as Exhibit ML-6 shows the flow rates of water that will normally be consumptively used by the Facility. The water requirements for the Facility will be met through purchase of water from the Cheyenne Board of Public Utilities.

The natural gas fuel supply for the proposed Facility will be supplied by Cheyenne Light. The Plant will utilize up to 30,000 Dth/day.

<u>Subsection 205(d).</u> A statement setting forth the need for the project in meeting present and future demands for service, in Wyoming or other states, and the proposed sale of the utility commodity or service which the construction of this facility will make available.

Cheyenne Light and Black Hills Power independently completed IRPs that analyzed the future resource needs of their customers. The following sections include information from both of those reports.

1. **Cheyenne Light**

    1.1. Resource Need Assessment

Cheyenne Light will need new electric resources to offset load growth and the expiration of long-term power purchase contracts occurring over the next several years. Although the economy in Cheyenne has seen slower growth in the past two years due to the current recession, industrial growth continues with load gains projected for the National Center for Atmospheric Research (NCAR), continued development of the Swan Ranch Industrial Park and indications of expansion plans from industrial customers. The Cheyenne Light electric system is expected to experience average annual load growth of approximately 1.5%.

Cheyenne Light currently owns one generating resource, the coal-fired Wygen II unit, and purchases the remainder of its requirements through power purchase agreements for coal-fired, natural gas-fired, and wind resources. Over a 20-year planning horizon, all of Cheyenne Light's PPAs expire. The contract with Black Hills Wyoming for 40 MW from CT2 expires in August 2014 and the Happy Jack and Silver Sage PPAs expire in 2028 and 2029, respectively. The PPA for 60 MW from Wygen I is expected to be replaced in kind at the time of its expiration.

To address the load growth and expiring PPAs, Cheyenne Light completed an IRP that provided a road map for defining the appropriate system upgrades, modifications, and additions required to ensure reliable and economic service to Cheyenne Light's customers now and for the future. The IRP, attached as Exhibit ES–1 to Eric Scherr's testimony, examined the needs of those customers with a thorough consideration of generation, including renewable energy and purchased power.

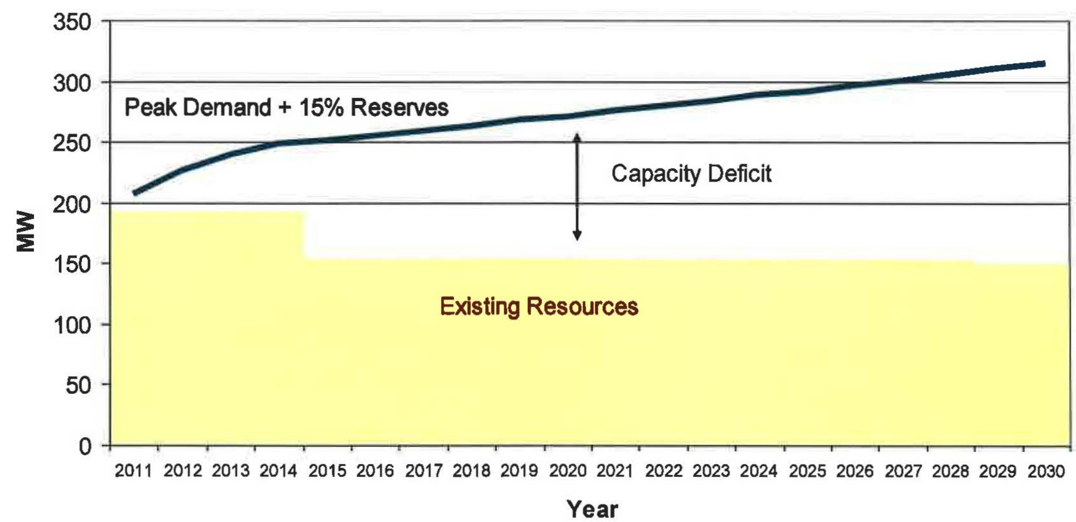
The IRP includes a load forecast that represents an average annual trended forecast growth rate of 1.5%, as well as expected load additions. The peak demand and energy forecast was developed by trending historical peak demands and annual energy and modifying the result to reflect load gains projected for expected load additions in 2012 through 2014 such as the Swan Ranch Industrial Park. The 2009 load shape was used to develop the hourly load forecast from the peak demand and annual energy projections. This load forecast assumes no large scale implementation of plug-in hybrid electric vehicles (PHEV) and no changes in the load shape over the planning horizon.

Cheyenne Light's energy efficiency program includes residential and commercial programs and forecasted reductions in load from the implementation of these programs were included in the load forecast. The residential electric portfolio offers customers opportunities to save energy with lighting, electric water heating, and second refrigerator recycle programs. This portfolio also offers an energy audit program. The commercial electric portfolio provides both a prescriptive rebate program and a custom rebate program. A brief description of each program is provided in the IRP.

The totality of the requirements for new resources, incorporating load growth, the need for a minimum planning reserve margin of 15%, expiring PPAs and reflecting that Cheyenne Light has no committed resources in its generation portfolio, is shown on Figure 1-1. The capacity deficit in any year is reflected as the distance between the line labeled "Peak Demand + 15% Reserves" and the top of the shaded blocks for "Existing Resources". In 2014 the capacity deficit is 93 MW and by the end of the planning horizon the deficit reaches over 150 MW.

Although there is no specified requirement for planning reserves by the Western Electricity Coordinating Council (WECC), prudent utility practice dictates that utilities plan for enough capacity to provide adequate reserves to ensure that electricity can continue to be provided during outages of the largest generating unit and/or the largest transmission line. Historically across the country, the level of planning reserve margin has generally ranged from 15 to 20 percent. The IRP assumed the planning reserve margin to be 15 percent. Cheyenne Light recognizes that as a standalone system, its planning reserve margin requirement could be higher than the 15% planning reserve margin assumption. As a result, Cheyenne Light anticipates negotiating a reserve sharing agreement with an affiliate in an effort to manage its reserve requirements and maintain a reliable system.

Figure 1-1
Cheyenne Light Load and Resource Summary



A comprehensive planning analysis that included capacity expansion modeling of eleven scenarios, utilizing stochastic analysis to quantify risk for each scenario and production cost modeling to determine relative present value of revenue requirements (PVRR) for each scenario is set forth in Exhibit ES-1 of Eric Scherr's testimony.

2. Black Hills Power

2.1. Resource Need Assessment

Black Hills Power's future resource needs are driven primarily by the impact of environmental regulatory requirements on its existing generating facilities. The EPA issued National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial Commercial and Institutional Boiler regulations are designed to reduce emissions of hazardous air pollutants from various small boilers, including coal-fired generating units of 25 MW or less. These rules directly impact the Ben French, Neil Simpson 1, and Osage coal-fired generating units of Black Hills Power. Currently the Osage units are in cold storage based on economics, but Ben French and Neil Simpson are in operation and relied upon for system capacity. Black Hills Power's future resource need is based on the upgrade or replacement of the Ben French and Neil Simpson 1 units. The Osage units have planned retirements in 2013 which are now confirmed due to the EPA rules.

In addition, the Reserve Capacity Integration Agreement (RCIA) with PacifiCorp terminates in 2012 which results in the effective loss of 28 MW of summer capacity. Over a 20-year planning horizon the existing PPAs with PacifiCorp, Happy Jack, and Silver Sage all terminate for a loss of 53.5 MW of accredited capacity.

To address the unit retirements and expiring PPAs, Black Hills Power completed an IRP that provided a road map for defining the appropriate system upgrades, modifications, and additions required to ensure reliable and economic service to Black Hills Power's customers. The IRP, attached as Exhibit ES–2 to Eric Scherr's testimony, examined the needs of those customers with a thorough consideration of generation, including renewable energy and purchased power.

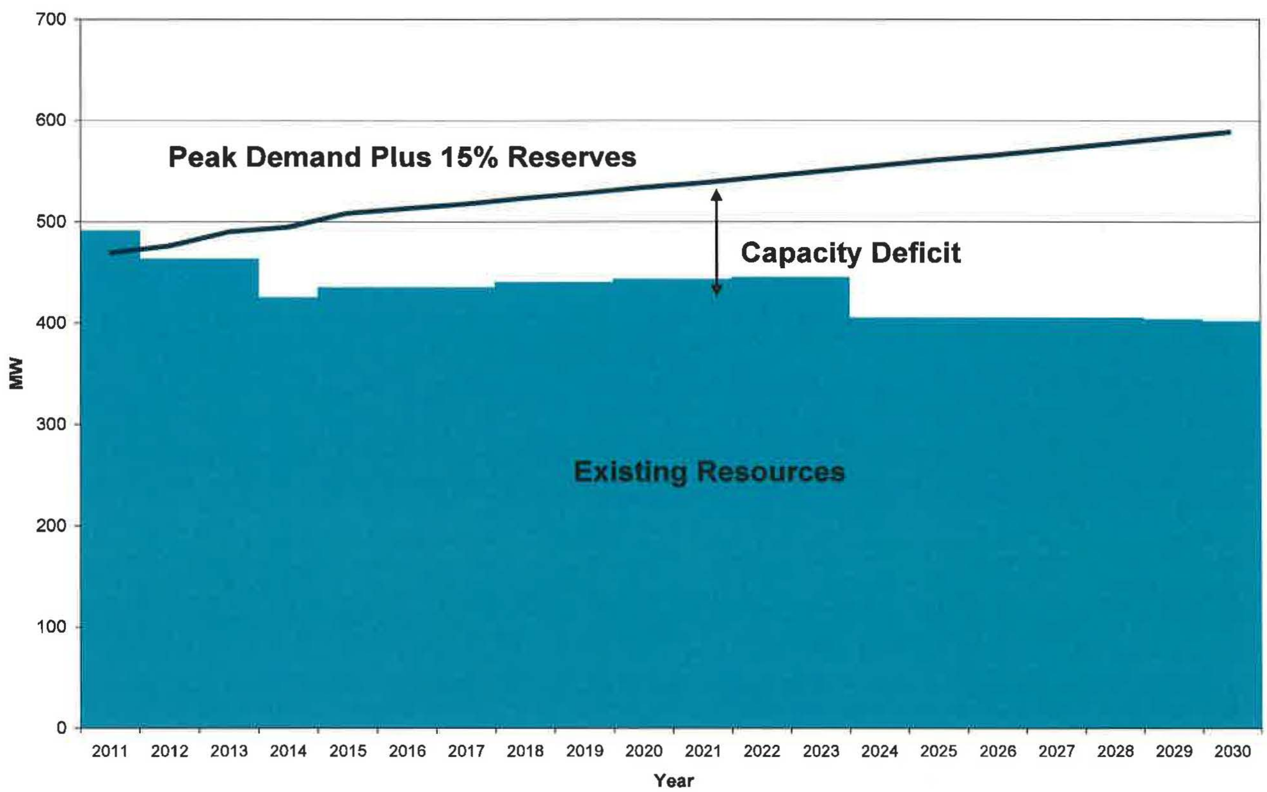
The IRP includes a load forecast that represents an average annual trended forecast growth rate of 1.0%, as well as expected load additions. The peak demand and energy forecast was developed by trending historical peak demands and annual energy and modifying the result to reflect load gains projected for expected load additions in 2012 through 2016. The 2009 load shape was used to develop the hourly load forecast from the peak demand and annual energy projections. This load forecast assumes no large scale implementation of plug-in hybrid electric vehicles (PHEV) and no changes in the load shape over the planning horizon and was adjusted to reflect the achievement of demand-side management programs.

Black Hills Power's demand-side management program includes residential and commercial programs and forecasted reductions in load from the implementation of these programs were included in the load forecast. The programs include residential and commercial programs for energy efficiency. The residential electric portfolio offers opportunities to save energy with water heating, refrigerator recycling, and heat pumps. This portfolio also offers school-based energy education, energy audits and weatherization programs. The commercial electric portfolio provides both a prescriptive rebate program and a custom rebate program. A brief description of each program is provided in the IRP.

As resources retire and existing PPAs terminate, other resources will be required to enable Black Hills Power to meet its obligations to serve the electricity needs of its customers. The totality of the requirements for new resources, incorporating the need for a minimum planning reserve margin of 15% and reflecting that BHP has no committed resources (resources that are planned and/or under construction but are not currently operational) in its generation portfolio, is shown on Figure 2-1. The capacity deficit in any year is reflected as the distance between the line labeled "Peak Demand Plus 15% Reserves" and the top of the shaded block for "Existing Resources". The capacity deficit in 2014 is 66 MW and reaches approximately 225 MW by the end of the planning horizon.

Although there is no specified requirement for planning reserves by the WECC, prudent utility practice dictates that utilities plan for enough capacity to provide adequate reserves to ensure that electricity can continue to be provided during outages of the largest generating unit and/or the largest transmission line. Historically across the country, the level of planning reserve margin has generally ranged from 15 to 20 percent. The IRP assumed the planning reserve margin to be 15 percent.

Figure 2-1
Black Hills Power Load and Resource Summary



A comprehensive planning analysis that included capacity expansion modeling of ten scenarios, utilizing stochastic analysis to quantify risk for each scenario and production cost modeling to determine relative present value of revenue requirements (PVRR) for each scenario is set forth in Exhibit ES-2 of Eric Scherr's testimony.

3. Resource Selection For Cheyenne Light and Black Hills Power

Consistent with its responsibility to meet customer energy needs in a way that is reliable and economic, the Applicant's resource planning approach includes both quantitative analysis and qualitative considerations. Quantitative analysis provides insights on future risks and uncertainties associated with market and fuel prices, load growth rates and other variables. Qualitative perspectives, such as the importance of fuel diversity and regional economic development are also important factors to consider as long-term decisions are made regarding new resources.

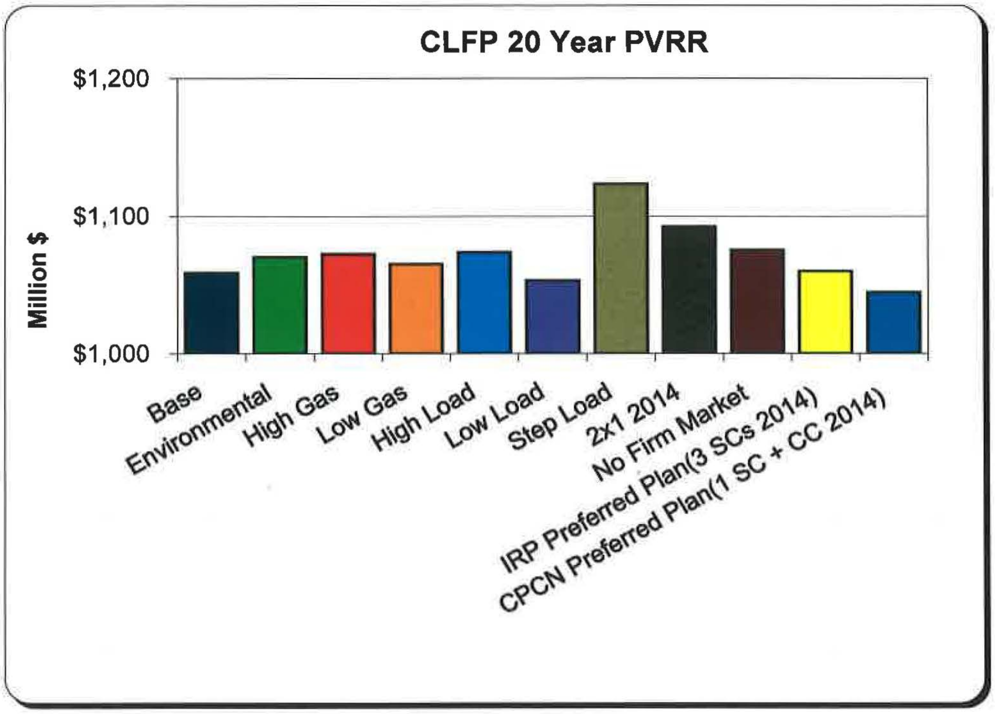
Company management uses all of these analyses and perspectives to ensure that the near-term and long-term customer needs are met while maintaining the operational flexibility to adjust to evolving economic, environmental and operating circumstances. As a result, the final resource selection, as described below, is a practical, logical and economic solution that benefits Cheyenne Light, Black Hills Power and their customers.

The preferred plan that led to the original CPCN filing on August 1, 2011 and as identified in the Cheyenne Light IRP recommends reliance on the market for firm capacity purchases in July and August of 2011, 2012, and 2013. In 2014, the plan recommends building or otherwise procuring three CTGs of approximately 38 MW each to accommodate forecasted load growth, to enable expansion possibilities, to mitigate shaft risk, and to handle future environmental regulation.

Following the completion of the Cheyenne Light IRP modeling, Black Hills Power began work to complete an IRP to identify the future resource needs of its customers. The preferred plan identified in Black Hills Power's IRP recommends reliance on the market for firm capacity purchases in July and August in years 2011-2023 and the conversion of an existing CTG to a gas-fired combined-cycle combustion turbine in the 2014 time frame. As a result of this outcome consideration was given to siting the Black Hills Power IRP identified resource in Cheyenne, presenting an opportunity for both companies to jointly-own a combined cycle resource.

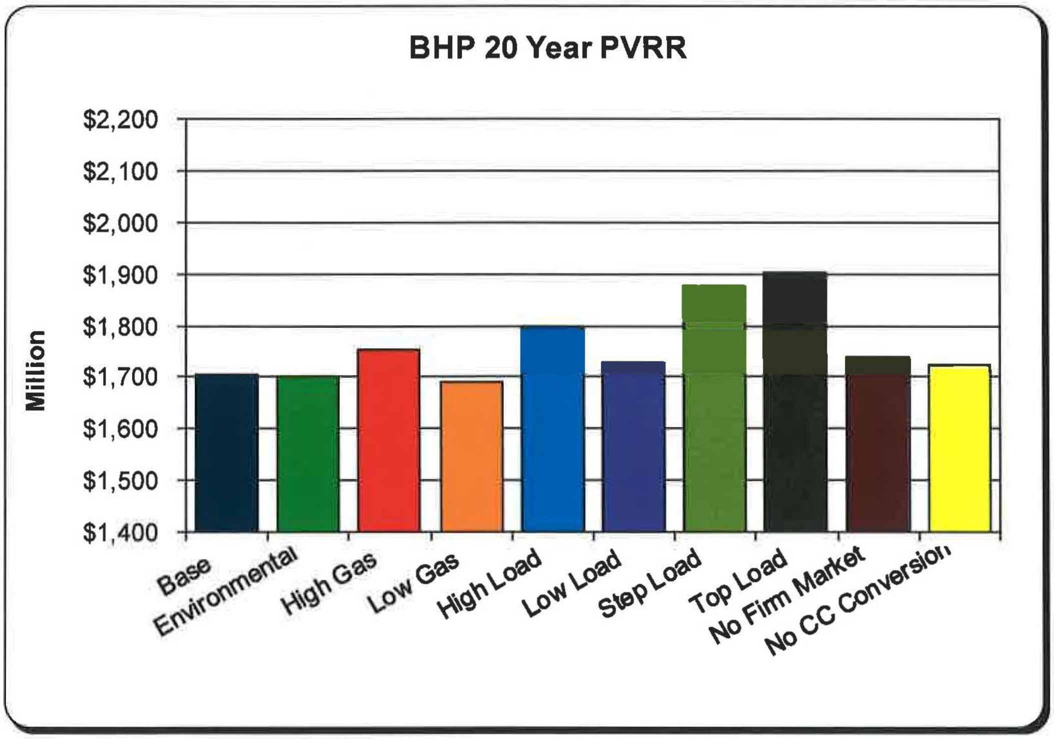
To assess the benefits of a jointly-owned CC unit additional modeling was undertaken to determine the financial impact on both Cheyenne Light's and Black Hills Power's completed resource plans. The results of the capacity expansion modeling showed that the Cheyenne Light model picks the CTG and a jointly-owned CC as the proposed resource additions when firm market purchases of up to 50 MW in all months are allowed. The production cost model was then run with the additional capacity purchases and the partial ownership of a CC unit. This modeling showed that the jointly-owned combined cycle unit (Cheyenne Light owns 42%, Black Hills Power owns 58%), one CTG wholly-owned by Cheyenne Light, and additional firm market purchases with associated capacity resulted in lower present value of revenue requirements (PVRR) than the resource scenario of three CTGs identified in Cheyenne Light's IRP. In Figure 3-1 below, the blue bar labeled "CPCN Preferred Plan (1 SC+CC 2014)" represents a PVRR reduction of 15.55 million dollars from Cheyenne Light's previous preferred plan labeled "IRP Preferred Plan (3 SCs 2014)".

Figure 3-1



As mentioned above, the Black Hills Power IRP preferred plan included the conversion of an existing CTG to a combined cycle unit. The combined cycle conversion option included in Black Hills Power's IRP analysis assumed that the full output of a combined cycle would be made available for Black Hills Power through the conversion of an existing wholly-owned CTG. To verify the impact of a jointly-owned combined cycle unit on Black Hills Power's preferred plan, additional modeling was completed. The ten (10) Black Hills Power scenario model runs shown in Figure 3-2 were remodeled with only 55 MW of a jointly-owned combined cycle unit available to Black Hills Power rather than the full 95 MW, as modeled in the IRP analysis. There was a slight increase in the 20-year PVRR of each scenario, but the increase was similar in all ten scenarios indicating the Base scenario is still the preferred plan for BHP.

Figure 3-2



4. Benefits of a Jointly-Owned Combined Cycle Resource

The benefits that result from the proposed resources (one combustion turbine and one jointly-owned combined cycle unit located in Cheyenne, Wyoming) include resource mix benefits, operational and environmental benefits, and market risk benefits. The lower heat rate of a CC provides several benefits including reduced reliance on economy energy markets, provision of a hedge against future natural gas prices, the ability to provide more economical system and wind regulation and lower emissions reducing exposure to future CO_2 taxes.

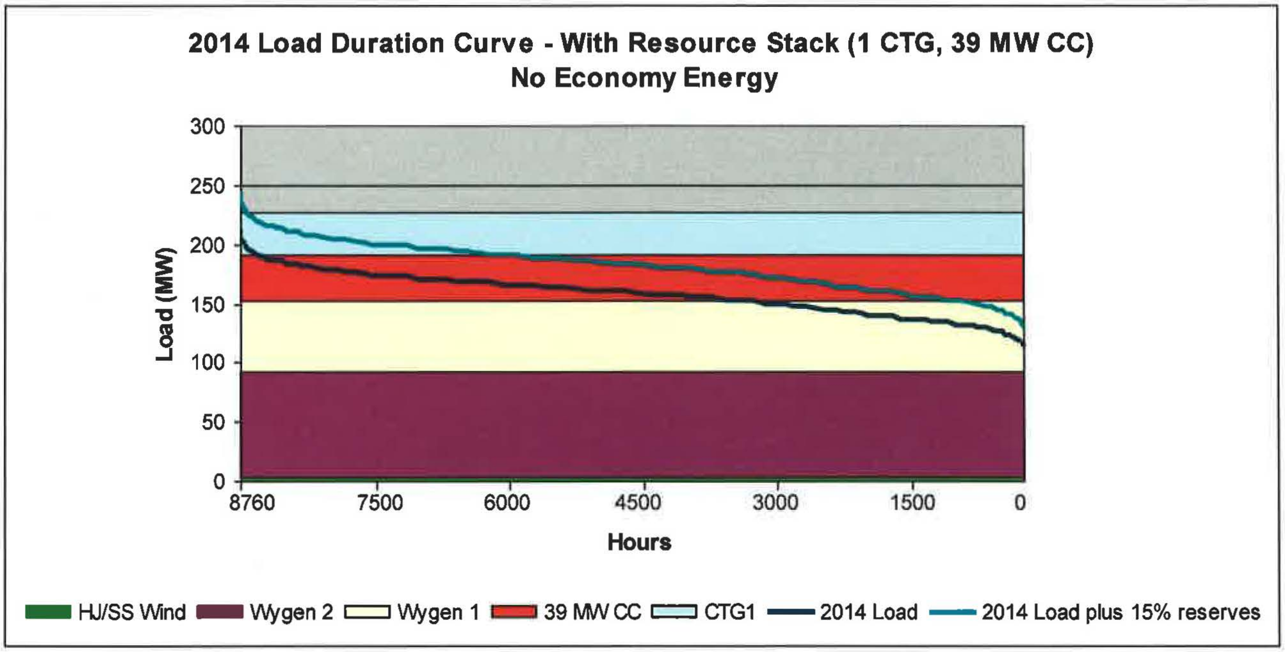
Cheyenne Light's preferred plan in the IRP that included three CTGs, utilized the economy energy market to supply a large portion of its energy need rather than operating the proposed CTGs. Economy energy markets currently offer attractive pricing but are subject to availability and possible curtailment. Curtailments cause Cheyenne Light to rely on its own resources to serve customer load even when it is more economical to purchase energy from the market. Economy energy is also subject to market conditions. In the relatively recent past, economy energy markets have traded on the daily market at over $1,000/MWh. To assess the risk associated with the unavailability of economy energy, capacity factors for the CTG and the CC with and without economy energy were compared. Table 3-1 demonstrates that in the event economy energy is not available or not economic, there is a sharp increase in the level of operation of the CTG and CC units. For example, this modeling indicates that in 2015, the annual capacity factor for the CC increases from 3.9% to 23.7% when economy energy markets are not available. Because a CC operates more efficiently than a CTG, Cheyenne Light customers will benefit from reduced operation costs.

Table 3-1

	Combined Cycle Capacity (%)		Simple Cycle Capacity (%)	
	w Econ Energy	w/out Econ Energy	w Econ Energy	w/out Econ Energy
2014	3.9	23.7	0.2	5.2
2015	2.6	25.6	0	9.4
2016	2.6	20.4	0	4.5
2017	3.2	22.2	0.9	7.6
2018	3.8	23.5	0.6	6.2
2019	4.4	23.2	2.5	10.1
2020	4.2	21.8	0.3	6.9
2021	4.6	24.7	1.6	9.7
2022	4.5	23.1	0.8	7.7
2023	8.1	43.5	1.4	16.6
2024	9.4	45.5	2.1	17.1
2025	6.7	43.8	1.1	17.2
2026	7.3	44.9	1.4	16.7
2027	7.6	47.2	1.4	19.1
2028	8.6	50.1	2	20.3
2029	9.2	53.8	1	23.1
2030	11	78.5	1.6	40.6

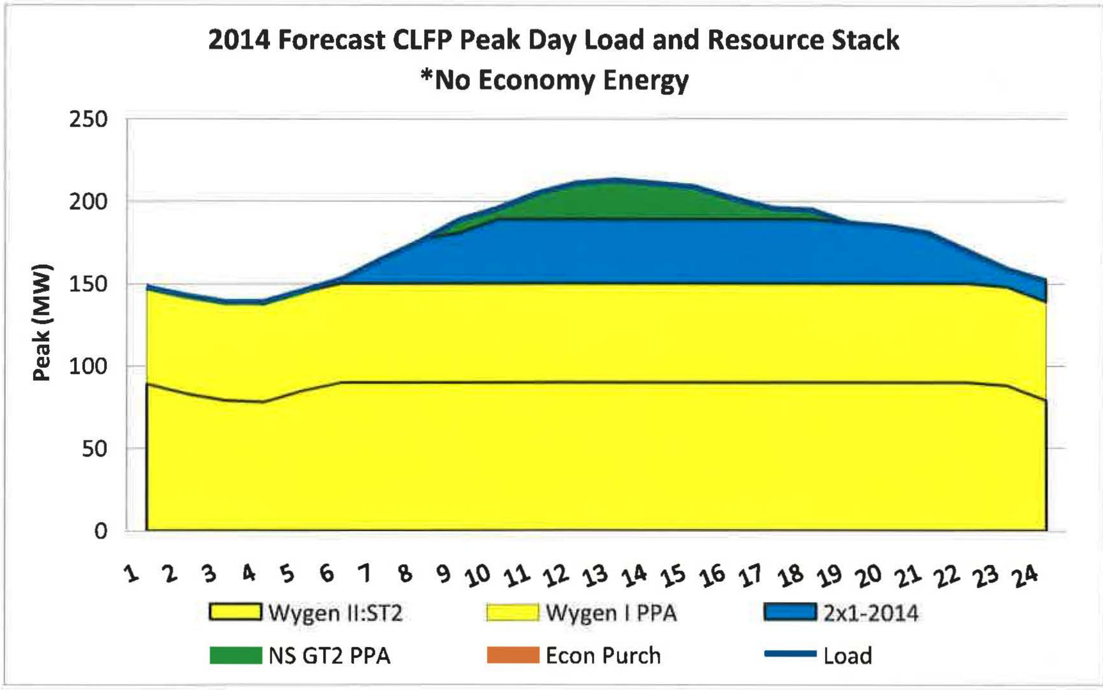
Figure 3-3 is a load duration curve (LDC) that illustrates the relationship between Cheyenne Light's forecasted 2014 load and the utilization of resources available to serve the load. In addition to existing resources, this graph includes the proposed ownership share of the CC and the proposed CTG when economy energy markets are not available. The LDC shows the 8,760 hours of load during the year sorted from highest load to lowest load. The blue line on the graph represents Cheyenne Light's 2014 forecasted load and the green line represents the forecasted load and the additional 15% reserve margin. The height of each resource slice is a measure of capacity and the X-axis measures the utilization rate or forecasted hours the resource will operate annually. Base load resources – Wygen 1 and Wygen 2 – represented by the yellow and purple slices, operate all hours of the year. The red bar in Figure 3-3 represents Cheyenne Light's ownership share in the combined cycle unit. The graph shows that without economy energy purchases, Cheyenne Light will need to run the combined cycle for 50% of the year to serve load. The size of the jointly-owned combined cycle fits well with Cheyenne Light's need shown by the high capacity factor of 25%.

Figure 3-3



Generating units for the electric utility industry are generally categorized as baseload, intermediate, peaking, or super peaking. Baseload generating units generally operate seven days per week, 24 hours per day to meet the demand that is always present. Intermediate capacity "stacks" above baseload capacity and meets demand that occurs for 10-12 hours per day. Peaking capacity operates for brief periods of time to meet high demand hours. Super peaking operates for those very few hours when loads are at their highest levels. A resource mix that consists of each of these types of capacity generally provides the most operating flexibility for utilities. Through a joint venture, both Cheyenne Light and Black Hills Power will have access to a CC unit further diversifying their resource portfolios. Figure 3-4 shows how Cheyenne Light's existing and proposed resources would be utilized on its forecasted peak day in 2014. Wygen I and Wygen II operate as baseload resources, the proposed CC will operate as an intermediate resource and the proposed CTG fills the peak need.

Figure 3-4



As mentioned previously, a CC unit operates at a lower heat rate than a CTG but only when it runs at near full capacity. Because Black Hills Power and Cheyenne Light share a similar coincident peak, weather patterns and load requirements, it is likely that these utilities will need to call on the unit at the same time. The combined need of the two utilities will allow the CC unit to operate at a capacity sufficient to achieve a low heat rate resulting in more economic energy for customers.

The CPCN application filed on August 1, 2011 by Cheyenne Light, Docket No. 20003-112-EA-11, requested approval of three (3) CTGs for a total capacity of 114 MW. Because of the opportunity to partner with Black Hills Power in a CC unit, Cheyenne Light has the opportunity to alleviate some market risk associated with economy energy purchases in exchange for some market risk associated with capacity energy purchases caused by reducing the built capacity to 77 MW. In addition, Cheyenne Light customers will likely benefit from the reduced capital expenditures in 2014.

For the reasons discussed above, Cheyenne Light has altered its decision on resource selection and is requesting approval for one (1) CTG and a 42% undivided ownership in one (1) CC for 77 MW of capacity. Black Hills Power is requesting approval of a 58% undivided ownership interest in one CC for 55 MW of capacity.

<u>Subsection 205(e).</u> A statement of the effect of the project on applicant's and other systems' stability and reliability, if applicable.

Cheyenne Light submitted two Large Generator Interconnection (LGI) applications through the FERC-approved Cheyenne Light Open Access Transmission Tariff (OATT). Black Hills Transmission Planning has completed a System Impact Study (Study) for the first request and has partially completed Study analysis on the second request. These Studies evaluate the potential effect the addition of the CC and CTG would have on the Cheyenne area transmission system. The Studies indicate that the CTG and CC will have a positive effect on the reliability of the Cheyenne Light and neighboring utilities transmission systems by reducing the power flow loading on area transmission facilities. This is primarily due to the generation being interconnected electrically "close" to the load center. Additionally, the Studies indicate that the CTG and CC will have no adverse effect on the area transmission system stability.

The addition of the 12" gas transmission pipeline to Cheyenne Light's system will not only supply the Plant with fuel but may also afford Cheyenne Light and its customers an additional gas pipeline for added reliability and system flexibility through the provision of a secondary transmission feed to Cheyenne Light's gas distribution system. The Applicants specifically request that this Commission determine and order that upon completion of construction of the Gas Pipeline as described herein, any further changes to the Gas Pipeline that may benefit the Cheyenne Light LDC system shall not be paid by nor be the responsibility of Black Hills Power and Cheyenne Light Electric Division.

Subsection 205(f). The estimated cost of and plans for financing the project, and a statement of the estimated effect of the project on applicant's revenues and expenses.

Cheyenne Light and Black Hills Power strive to maintain a typical utility capital structure including long-term debt and equity. The Applicant's objective will be to finance the construction costs of this project with short-term borrowings and internally generated funds. Short term borrowings may be drawn from Black Hills Corporation's utility money pool. The exact type and timing of long term financing for this Facility cannot be determined at this time but will depend on then current financial market conditions. It is expected that permanent long term financing will be through the assignment of Black Hills Corporation debt, issuance of first mortgage bonds by Black Hills Power and Cheyenne Light for their respective capital investment and/or equity invested by Black Hills Corporation. Please see Subsection 204(h) for the estimated annual revenues and expenses resulting from the Facility.

Subsection 205(g). A list of local, state, Indian, or federal governmental agencies having requirements which must be met in connection with the construction or operation of the project, and the status before those agencies; and applicant shall file such agency's final order when entered.

The Applicants recognizes that the Facility must comply with all local, state, and federal regulations and permit requirements, and understands that certain permits are required prior to commencing construction and/or operation. Table 4 (below) provides a list of permits and approvals that must be obtained in addition to the CPCN from the Commission.

TABLE 4
POENTIALLY NECESSARY PERMITS, APPROVALS, AND CONSULTATIONS

Issuing Agency/Permit Name	Permit	Details	Status
U.S. Army Corps of Engineers (USACE)	Jurisdictional Determination; Section 404/Individual or Nationwide Permit; Preconstruction Notice	Required for discharge of dredged or fill material into waters of the United States, including adjacent wetlands.	
Federal Aviation Administration	Notice of Proposed Construction or Alteration	Construction of structures over 200 feet. Approximate 60-day process for application development and approval.	

TABLE 4 POENTIALLY NECESSARY PERMITS, APPROVALS, AND CONSULTATIONS			
Issuing Agency/Permit Name	**Permit**	**Details**	**Status**
EPA	Safe Drinking Water Act	Potable water system at the plant. Water system, certified operator and sampling/operating plan required.	
EPA	Air Permit	Issues GHG permit and reviews the Prevention of Significant Deterioration (PSD) permit for criteria pollutants for comment	
	The Spill Prevention Control and Countermeasure (SPCC) Plan is a federal requirement (40CFR112) for facilities that store specific amounts of petroleum products.	For above ground oil storage onsite, including fuels and transformers, a SPCC Plan is required for 1,320 or more gallons of oil maintained on site.	
	EPA ID number issued; assigned as a Conditionally Exempt Small Quantity Generator (CESQG)	CESQG generate 100 kilograms or less per month of hazardous waste, or 1 kilogram or less per month of acutely hazardous waste.	
WDEQ;Issuing Agency	Prevention of Significant Deterioration (PSD) Construction Permit	PSD applies to new major sources or major modifications at existing sources for pollutants where the area the source is located is in attainment or unclassifiable with the National Ambient Air Quality Standards (NAAQS) for criteria pollutants. This process also requires issuance of a GHG permit by EPA.	
	Title V Permit (Section 112(b))	Title V operating permits are required for all major sources (i.e. with the potential to emit 10 tons per year (tpy), or more, of any hazardous air pollutant listed pursuant to 112(b); 25 tpy, or more, of any combination of hazardous air pollutants listed pursuant to 112(b)).	
	Acid Rain Air Permit (Title IV)	This permit is a portion of the larger Title V permit and specifies each unit's allowance allocation and NOx limitation (if applicable), and also specifies compliance plan(s) for the affected source.	
WDEQ	Air Quality Permit, Fugitive Dust	Sources operating within the State of Wyoming are required to control fugitive dust emissions as outlined in Chapter 3, Section 2(f) of the Wyoming Air Quality Standards and Regulations	
	Wyoming Industrial Development Information and Siting Act/ Industrial Siting Commission Order Industrial Siting Permit	If estimated capital cost of a project facility is in excess of $180.2 million (W.S. 35-12-102(vii)), the applicant is required to obtain a permit, or waiver of permit, before initiating construction. In addition, if the potential project costs are within 80 percent or greater of the $180.2 million threshold, the applicant is required to file a Non-Jurisdiction Certificate Application.	

TABLE 4 POENTIALLY NECESSARY PERMITS, APPROVALS, AND CONSULTATIONS			
Issuing Agency/Permit Name	**Permit**	**Details**	**Status**
	National Pollutant Discharge Elimination System (NPDES) Large Construction General Permit (WYR10-0000)	Construction projects that disturb 5 or more acres must be covered under the general construction permit. This permit requires a Notice of Intent (NOI), and a Storm Water Pollution Prevention Plan (SWPPP Plan), containing erosion control measures.	
	Permit to Construct Small Wastewater Facilities (Septic Tanks and Leachfields)	Required for construction of leach field or septic system that has greater than 2000 gallons per day.	
	Section 401 Water Quality Certification/ Temporary Increase in Turbidity	Required for individual and specified nationwide wetland permits and/or stream crossings that have the potential to degrade or impact state waters.	
Wyoming Department of Transportation (WYDOT)	Right-of-Way Encroachment/ Driveway Access Permit	Issuance required for any activities impacting highways or within highway easements, including road crossing. Driveway access permit required if access to site is from roads maintained by Wyoming DOT	
Wyoming State Historic Preservation Office (SHPO)	Section 106 of National Historic Preservation Act of 1966, as amended (16 U.S.C. 470 et seq.) and Advisory Council Regulations on the Protection of Historic and Cultural Properties, as amended (36 CFR 800)	Will be necessary for undertakings with proposed federal nexus (e.g., on federal lands, federally regulated interconnect), or if the project falls under jurisdiction of the Industrial Siting Act (ISA).	
Laramie County Planning and Development Office/ City of Cheyenne Planning and Development	Preliminary Development Plan, Site Plan Application, Commercial Building Permit	Required for development and construction of the facility. May require an Environment and Services Impact Report and Open Hole (Soils) Report, as well as additional resource studies. Requires review and approval by the Planning Commission.	
	Grading, Erosion, and Sediment Control Permit	Required for all land disturbing activities related to non-residential development.	
	Address Application	Required for all new development.	
	Sign Permit	Required for outdoor signs associated with the project.	
	Zoning Permit	Required for rezoning of land parcels.	
	Floodplain Development Permit	Required if project is to be developed within a Federal Emergency Management Agency (FEMA) designated floodplain.	
Board of Public Utilities (City of Cheyenne)	Industrial Discharge Permit	This permit is required for Plant effluent discharge to the CBOPU wastewater treatment facility.	

TABLE 4 POENTIALLY NECESSARY PERMITS, APPROVALS, AND CONSULTATIONS			
Issuing Agency/Permit Name	**Permit**	**Details**	**Status**
Laramie County Public Works Department	Driveway Access Permit County Road Permit	Required for driveway access off roads maintained by the county. Required for roadway excavation and bores	
U.S. Fish and Wildlife Service	Approval	Required for transmission route	
Wyoming Game and Fish Department	Approval	Required for transmission route	

Subsection 206(a). A general description of the devices to be installed at the major utility facility to protect air, water, chemical, biological and thermal qualities; the designed and tested effectiveness of such device; and the operational conditions for which the devices were designed and tested.

The Facility is being designed in a manner that the construction and operation of the Facility will not present a danger to the air, water, chemical, biological, or thermal qualities of the site. All steps necessary under state and federal law will be taken to ensure the quality of the site. Emissions for NO_x, CO, SO_2, VOC, particulate (PM_{10}) and hazardous air pollutants (HAPs) will meet both short term and annual permit limits. The Facility will also have a CO_2 BACT permit limit related to the recently issued Greenhouse Gas PSD Tailoring Rule.

1. **Air Emissions**

The Facility is being designed to utilize the BACT. The following is a summary of the proposed BACT for air emissions and associated emission rates, as permitted by the WDEQ, Air Quality Division.

Nitrogen Oxides - Nitrogen oxide emissions from the CTG and CC CTG will be controlled with Dry Low NO_x burners (DLN) and selective catalytic reduction (SCR) with ammonia injection. The NO_x control systems will be designed to meet the limits in an approved air permit. The SCR system functions by injecting ammonia into the flue gas stream just upstream of a catalytic reactor. The NH_3 molecules in the presence of the catalyst, dissociate a significant portion of the NO_x into nitrogen and water.

Carbon Monoxide and VOCs – Carbon monoxide emissions from the CTG and CC CTG will be controlled with Dry Low NO_x burners (DLN) and catalytic oxidation (CatOx). The CO control systems will be designed to meet the limits in an approved air permit. The CatOx system also reduces VOCs emissions by approximately 50 percent.

Particulate – The use of pipeline natural gas (PNG) in the CTG and CC will minimize PM_{10} emissions. The wet cooling tower associated with the CC will have high efficiency drift eliminators installed to reduce particulate emissions.

Sulfur Dioxide – The use of PNG in the CTG and CC will minimize sulfur dioxide (SO_2) emissions.

Hazardous Air Pollutants – The use of PNG in the CTG and CC will minimize the emissions of HAPs. The CatOx system will also significantly reduce organic HAP emissions.

2. **Water, Chemical, Biological and Thermal Qualities**

All chemical containing equipment will be surrounded by a curbed area or other containment method in order to contain spillage and prevent exposure to storm water runoff. Drains from the chemical feed areas will be contained locally, and pumped to a waste truck if required.

Spent CTG and CC CTG wash water will be collected in the CTG and CC CTG wash drain tanks. The spent CTG and CC CTG wash water contains detergent and could contain some oily residue from turbine washes. The water will be pumped into a chemical waste removal truck for disposal as needed.

Mechanical equipment drains potentially containing oil residue will be collected in a dedicated system and processed by an oil/water separator. Clean effluent water from the oil/water separator will then be discharged to the CBOPU water treatment facility. Oil will be pumped out of the oil/water separator's oil containment compartment as required and trucked offsite to a licensed processing facility.

Spent cooling tower blowdown and sanitary wastewater will also be discharged to the adjacent CBOPU water treatment facility or be discharged to either Crow Creek or Dry Creek with a NPDES discharge permit.

The unit will be provided with weatherproof, acoustic enclosures.

The Facility will be designed to protect the environment. All steps necessary under state and federal law will be taken to ensure the quality of the project site.

Subsection 206(b). The name of any body or source of water or river along which the major utility facility will be constructed or from which it will obtain or return water.

The Facility will be constructed near Crow Creek and Dry Creek. Water sources for the Facility will not come from or be discharged to either Crow Creek or Dry Creek without a NPDES discharge permit.

The Facility will receive potable water from the CBOPU municipal water system, the Facility's treated water system will utilize wastewater effluent water from the CBOPU wastewater treatment plant and the Facility's sanitary wastewater will be directed to the CBOPU treatment plant that is located adjacent to the Facility. The Applicants notified the City of Cheyenne of the water requirements for the proposed Facility and has obtained approval for the required volume of potable water and wastewater effluent water. In addition, the Applicant's will obtain an Industrial Discharge Permit from the City of Cheyenne.

Subsection 206(c). A geological report of the station site include foundation conditions, groundwater conditions, operating mineral deposits within a one-mile radius; and a topographical map showing the area within a five-mile radius.

1. **Project Site**

The area surrounding the project site can be described as undulating and rolling and is typical of the high plains and grasslands located in southeastern Wyoming. The topography is marked by a high terrace or knoll at approximately 5,970 feet above mean sea level (MSL) and then descends slowly by approximately 50 feet in elevation to the southeast and southwest towards Crow Creek and Stewarts Ditch. The topography ascends again near a line of hills and terraces to the south approximately one-half mile from the southern border of the site. Crow Creek flows to the southeast and borders the project site to the south at an elevation of 5,918 feet MSL, receiving drainage from offsite ephemeral tributaries and the Hereford Ranch Reservoir to the west. Topography is shown on Exhibit ML-4 attached to the testimony of Mark Lux.

Soil conditions have been evaluated in an October 2005 report by Terracon, which is attached as Exhibit ML-7 to Mark Lux's testimony, when a geological site investigation was conducted to test the feasibility of constructing new building foundations at the site (Terracon, 2005). Regionally, the surficial and subsurface soils overlie the Tertiary and Quatenary deposits of the Ogallala Formation. The contact with the Ogallala is estimated to be the first distinct clay, silt, or sandy clay layer below the unconsolidated Quaternary deposits. Quaternary terrace deposits range in thickness from about 10 to 30 feet and consist of interbedded clay, sand, and gravel. The Ogallala Formation is predominantly interbedded clayey sand, fine, sandy silt and sandy clay, with several sandstone lenses. The detailed discussion of the site geology is limited to the Ogallala Formations of the Tertiary age located within the site boundary. The Ogallala is the only formation directly affecting site development, including foundation and groundwater conditions at the project site. Soil and geologic maps of the area surrounding the site are presented as Exhibits ML-8 and ML-9 respectively to Mark Lux's testimony.

Soil samples consisting of silty sand, well graded sand, and silty clayey sand were documented during the geotechnical investigation and are indicative of the terraced alluvial deposits caused by gently inclining and relatively flat surfaces within the Ogallala formation. Based on geological contact maps, the predominant surficial geological feature across the site that defines the vadose zone (geological formation, primarily soil horizons encountered before the first water bearing aquifer) and foundation conditions is terrace deposits (Case et al., 1998). Attached Exhibit APP-2 lists all references included within Subsection 206(c). The terrace consists of relict alluvial deposits on flat and gently inclined surfaces that are bounded to the west by a relatively ascending slope and to the south by a relatively steeper descending slope and then ascending slope beyond Crow Creek. The soil encountered in the vadose zone and foundation zone from approximately 1 foot (ft.) below ground surface (bgs) to approximately 15 ft. bgs consists of well drained, loose to dense sands with silty sand to 5 ft. bgs and either well-graded, medium dense to dense sand or silty clayey sand to approximately 12 ft. bgs. Medium dense to dense silty sand extends between 10 to 20 ft. bgs at varying percentages.

The actual contact between the surficial geological features of the Tertiary and Quatenary deposits and the Upper Miocene bedrock formation is unknown within the site boundary, but it is estimated to be below the extent of the Ogallala formation depth of approximately 30 ft. bgs. The Upper Miocene rocks of the early tertiary epoch are the dominant bedrock formation below the Ogallala across the site. Immediately to the south of the site boundary, the Upper Miocene formation is in contact with the more recent bedrock formation of the alluvial and colluvium deposits caused by ancient stream erosion and gravity within the Crow Creek stream basin, consisting of loose and incoherent rocks. If excavation activities are expected to extend below 40 ft. bgs, then consolidated bedrock may be encountered and additional heavy equipment will be necessary to drive foundation piles or other building stabilization tools into the bedrock formation.

The hydrologic properties of these soils are considered Group B as defined by the U.S. Department of Agriculture soil classification system, consisting of moderate infiltration rates and are well drained with moderately fine and coarse textures (USDA, 2011 and USDA, 2007). Surface water transmission is moderate and indicates a low capillary capacity or ability to hold water within the soil horizon. Excavation activities within the near surface to approximately 5 ft. bgs will require careful attention to slope stability due to the unconsolidated sandy soils. Beyond 10 to 15 ft. bgs, heavy excavation equipment will be required due to the higher percentage of cohesive silty sands and clayey sands.

With the presence of Group B soils, recharge of the shallow aquifer will be predictable and at a higher rate in some areas with more sandy conditions than those with silty or clayey soils present. Data collected during the geotechnical investigation indicates the depth to groundwater to be greater than 20 ft. bgs as indicated by the lack of groundwater present in any of the twelve borings advanced across the site. The investigation, however, was conducted in the fall during a period of lower than normal precipitation when groundwater recharge may have been limited. The presence, therefore, of shallow groundwater within the unconsolidated water bearing unit less than 20 ft. bgs is possible during the winter, spring, and early summer periods. Although the groundwater gradient and average flow direction has not been formally calculated, it is expected to follow the drainage topography of the site towards Stewart Ditch and Crow Creek to the south. Further, the Tertiary and Quatenary deposits found within the shallow and deep aquifers are hydraulically connected and these water bearing strata are referred to as the High Plains Aquifer (USGS, 1967).

Based on the suspected flow of groundwater towards Crow Creek to the south, it is expected that groundwater may be encountered at depths less than 20 ft. bgs within the southern half of the project site. The presence of shallow groundwater less than 20 ft. bgs within the higher elevations located in the northern half of the project site is less likely, but still possible due to aquitards or other features where more consolidated fine soils within the vadose zone demonstrate higher water holding capacity. During excavation, monitoring for groundwater intrusion will be necessary. Additional precautions to avoid impacting groundwater caused by equipment fuel leaks or spills may be required based on site conditions, but is unclear without additional on-site depth to groundwater measurements.

While further investigation is required, Cheyenne Light is not aware of the presence of operating mineral deposits within the project site or within a one mile radius. Within Wyoming, extraction for ore deposits such as coal and precious metals have occurred further to the north in the Powder River Basin and to the west in areas such as the Wind River Valley near the higher elevations of the Absaroka Mountains and Wind River Mountains.

2. Proposed Pipeline Corridor

The area surrounding the proposed pipeline corridor associated with the project site can be described as undulating and rolling, and is typical of the high plains and grasslands located in southeastern Wyoming. The pipeline corridor is shown in Exhibit APP-3 and the corridor comprises an area approximately three miles wide from east to west by nine miles in length from north to south.

For discussion purposes, the proposed pipeline corridor (the corridor) has been separated into three segments as presented in Exhibit APP-3. The northern section of the corridor contains the lowest elevations at approximately 5,900 to 5,950 ft. above mean sea level (MSL) where Crow Creek flows from west across the corridor to the east through the Hereford Ranch reservoir and continuing on towards the southern boundary of the project site. The slope rises gently to the south approximately 200 ft. to form terraced and plateau hills that are part of the same range encountered directly south of the project site as described above. Based on images obtained from on-line geospatial tools, an open rock quarry is located within the corridor approximately ¾ mile south-southeast of the Hereford Reservoir with an operational footprint approximately 214 acres. No other mineral or ore mining operations are known to be present within the corridor. Based also on a review of the Wyoming Oil and Gas Commission's online database, it is apparent that numerous wells are located within the corridor. No other mineral or ore mining operations are known to be present within the corridor.

Moving south from Crow Creek and Hereford Ranch within the northern portion of the corridor, the upper Miocene rock features dominate the surficial geological profile within the terraced hills and plateaus as shown on Figures 2-A through 2-C (Case et al., 1998). A transitional surficial geological profile of slope wash and residual deposition from Miocene rock decomposition mixed with alluvial and co-alluvial stream sediments is present immediately adjacent the Crow Creek and Hereford Reservoir stretching ½ to ¾ mile to the south. Beyond this contact, the surficial bedrock profile consists of bench and mesa deposits and exposed sandstone lenses extending approximately 3.5 miles to Porter Draw, where a terraced alluvium is present along the stream channel. Immediately south of Porter Draw, the bench and mesa rock formations continue to the southern boundary of the corridor.

Similar to the project site, the soil contained within the Quaternary deposition of the Ogallala formation is the only soil profile that should affect pipeline construction activities. The Quaternary terrace deposits found along the corridor are predominately interbedded with clayey sand, fine sand, sandy silt and sandy clay with several sandstone lenses. Soil boring profiles for specific areas along the corridor were not available for analysis and may be required prior to construction activities to obtain additional geotechnical data. A depiction of surficial soil characteristics within the corridor is shown on Exhibit APP-3. Soil conditions along the Crow Creek stream channel and the Hereford reservoir consist of alluvial silty clay loam and are relatively poorly drained, which is consistent with a gaining stream such as Crow Creek. South of Crow Creek, the soil profile varies between clayey sand, fine sand, silty sand, and sandy clay as described above within the Quaternary deposits of the unsaturated and saturated vadose zone (USDA, 2011 and USDA, 2007).

In contract to the project site, measured depth to groundwater measurements were not available for the pipeline corridor. It is expected that groundwater conditions are similar to the project site and depth to water is greater than 20 ft. bgs and varies with seasonal conditions.

Conclusion

For the reasons discussed in this Application and the supporting documents, the Applicants believe that the construction of the Facility is prudent and in the best interests of the customers of Black Hills Power and Cheyenne Light. Applicants pray that the Commission enter an Order granting Applicant a Certificate of Public Convenience and Necessity authorizing the construction, operation, and maintenance of the Gas-Fired Combustion Turbine Electric Generating Power Plant and Related Facilities, including a high pressure gas line and transmission line, as described herein.