Direct Testimony
Mark Lux

Before the South Dakota Public Utilities Commission of
the State of South Dakota

In the Matter of the Application of
Black Hills Power, Inc., a South Dakota Corporation

For Authority to Increase Rates
In South Dakota

Docket No. EL12-___

December 17, 2012

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EXHIBITS

None

I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark Lux. My business address is 1515 Wynkoop Street, Suite 500, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Black Hills Service Company, a wholly-owned subsidiary of Black Hills Corporation ("Black Hills Corporation"), as Vice President and General Manager, Regulated and Non-Regulated Generation. In that role, I am responsible for the operation and construction of the electrical power generation and coal mining assets owned by Black Hills Corporation subsidiaries, including Black Hills Power, Inc. ("Black Hills Power" or the "Company").

Q. FOR WHOM ARE YOU TESTIFYING ON BEHALF OF TODAY?

A. I am testifying on behalf of Black Hills Power.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I received a Bachelor of Science degree with honors in Mechanical Engineering from the South Dakota School of Mines and Technology in 1987. I have more than 25 years of experience working in the mining and electrical power industry, in both nuclear and fossil fuel power generation, including operating experience and power plant construction experience. I have been involved in the development, engineering, construction and commissioning of several coal-fired power plants, including Black Hills Power's Wygen III plant and Neil Simpson II plant. I have also been involved with the development, engineering, construction and commissioning of several coal-fired and gas-fired power plants owned or developed by subsidiaries of Black Hills Corporation, including the recent construction of simple cycle and combined cycle natural gas-fired units in Colorado.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide background information on Black Hills Power's generation assets. I address the environmental laws and regulations that are impacting Black Hills Power's operational decisions with regard to its small coal-fired generating units. I discuss the Company's major capital additions related to environmental regulation and related to generation efficiency and reliability. I discuss anticipated plant closures and the economic shutdown until plant retirement. I describe Black Hills Power's plans for a generating asset addition at the Cheyenne Prairie Generating Station.

III. GENERATION ASSETS

Q. PLEASE DESCRIBE THE GENERATION ASSETS OF BLACK HILLS POWER.

A. Black Hills Power owns 471 MW of electric utility net generation capacity as follows:

Unit	Fuel Type	Location	Ownership Interest (%)	Gross Capacity (MW)	Year Installed
Osage	Coal	Osage, WY	100	34.5	1948-1952
Ben French	Coal	Rapid City, SD	100	25.0	1960
Neil Simpson I	Coal	Gillette, WY	100	21.8	1969
Neil Simpson II	Coal	Gillette, WY	100	90.0	1995
Wyodak	Coal	Gillette, WY	20	72.4	1978
Wygen III	Coal	Gillette, WY	52	57.2	2010
Ben French Diesel #1-5	Oil	Rapid City, SD	100	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, SD	100	80.0	1977-1979
Neil Simpson CT	Gas	Gillette, WY	100	40.0	2000
Lange CT	Gas	Rapid City, SD	100	40.0	2002

In addition, Black Hills Power purchases 50 MW under a long-term agreement expiring in 2023 and 14.7 MW and 20 MW under long-term agreements expiring in 2028 and 2029, respectively.

IV. ENVIRONMENTAL ISSUES

Q. ARE THERE NEW ENVIRONMENTAL REGULATIONS AFFECTING BLACK HILLS POWER'S GENERATION FLEET?

A. Yes. The Environmental Protection Agency ("EPA") issued National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial and Institutional Boilers (herein "Area Source Rules"), on March 21, 2011 with an effective date of May 20, 2011. The deadline to comply with these rules is March 21, 2014.

Q. PLEASE GIVE A BRIEF DESCRIPTION OF THE AREA SOURCE RULES.

A. Area Source Rules are designed to reduce emissions of hazardous air pollutants from various small boilers, to include coal-fired units of 25 MW or less. Specifically, the rules implement: (1) new emission requirements for mercury and carbon monoxide; (2) work practice standards addressing startup and shutdown and energy assessments; (3) operating restrictions defining mercury sorbent injection rates and coal quality; (4) continuous monitoring; and (5) compliance testing. Operating older units in compliance with these rules would require significant expenditures, including the addition of emission controls, installation of monitoring equipment, restrictions on quality of the coal received and adherence to new operating parameters established during the compliance test.

Q. WHICH GENERATING RESOURCES OWNED BY BLACK HILLS POWER ARE AFFECTED BY THESE RULES?

A. Black Hills Power owns three coal-fired power plants equipped with boilers of 25 MW or less: Neil Simpson I, Osage and Ben French. All three of these plants are subject to the Area Source Rules.

Q. WHAT IS THE EFFECT OF THE AREA SOURCE RULES ON THE NEIL SIMPSON I, OSAGE AND BEN FRENCH UNITS?

A. These rules require either: 1) the retrofit of expensive new environmental controls on Neil Simpson I, Osage and Ben French; or 2) retirement of the affected units. Furthermore, if these older facilities are to continue to operate with new emission controls to meet these regulations, life extension upgrades would be required. It is highly likely that if this happens, the EPA will initiate New Source Review ("NSR") investigations, which historically have led to significant capital costs to meet Best Available Control Technology emission limits similar to those of new plants. Additionally, NSR now requires adherence to the Green House Gas New Source Performance Standard ("GHGNSPS") implemented in 2012 by EPA. The GHGNSPS requires coal-fired plants that impact thresholds of greenhouse gas emissions to install carbon capture and sequestration within 10 years and achieve carbon emission limits equal to natural gas-fired emissions of 600 pounds per megawatt hour on a 12-month annual average. As a result of these factors, as well as the likelihood of additional future EPA regulations affecting the continued operation of these facilities, Black Hills Power concluded that the most cost effective plan for EPA compliance is to retire Neil Simpson I, Osage, and Ben French on March 21, 2014, the EPA deadline for compliance of the Area Source Rules.

Q. HOW WILL THE PLANT SHUTDOWNS BE STAGED?

A. The three Osage units and Ben French have been placed in economic shutdown and will remain in that condition until their March 21, 2014 retirement. Neil Simpson I is expected to continue to operate until its March 21, 2014 retirement. The three Osage units were placed in economic shutdown on October 1, 2010. The Ben French unit was placed in economic shutdown on September 1, 2012. Ben French last generated energy on August 31, 2012.

Q. WHAT IS ECONOMIC SHUTDOWN?

A. Economic shutdown is when a generating unit is removed from service because the cost to operate it is not competitive in the market and it is not required to meet demand. Economic shutdown assumes that replacement power can be acquired at a lower cost from the market or that native load demand does not require generation from the asset due to economic conditions in the service territory. During economic shutdown, plants can be reactivated with thirty days advance notice. However, steps need to be taken to protect the equipment during economic shutdown.

Q. WHAT STEPS NEED TO BE TAKEN TO PROTECT EQUIPMENT DURING ECONOMIC SHUTDOWN?

A. Although the steps needed to be taken to protect equipment vary from plant to plant because of differences in design, the major items that need to be addressed include the following:

- Boiler vented and drained hot during shutdown of the unit. If the unit is a long-term asset, consideration should be given to displacing oxygen in the boiler with nitrogen (nitrogen blanketing) to avoid oxidation damage.
- All feedwater and condensate piping and vessels require draining (all internal water and steam piping drained at low point drains).
- Ensure that ash hoppers, ductwork and precipitator are cleaned of excessive ash accumulations to avoid corrosion and hardening of ash.

- Ensure all water pumps are drained to avoid freezing and corrosion damage. Some pumps require disassembly as drains are not provided.
- Drain cooling tower and circulating water system to avoid corrosion or freeze damage.
- Drain oil from cooling tower gearboxes to avoid moisture accumulation and subsequent freezing and potential environmental spill incident. Tower gearbox blades must be secured to avoid spinning due to wind draft.
- Lockout and tagout all switchgear with potential to be started that might result in damage to equipment.
- Purge hydrogen from generator (on hydrogen-cooled machines) and displace with dry air.
- Shut off turbine/generator lube oil system, ensure moisture is drained from bottom of tank and turn oil heaters off. Leave oil in tank. Several days prior to start up of the unit, oil heaters and vapor extractor must be started.
- Pull generator brushes out to avoid damage to the collector rings. Ensure shaft ground is functional and installed.
- Install grounding breakers in major buss work to discharge any stray voltage (safety precaution).
- Clean out all coal storage vessels to avoid spontaneous combustion.
- Open condenser to vent moisture to atmosphere and avoid oxidation of turbine components.

- Blowdown and isolate instrument air systems to avoid moisture accumulation and subsequent instrument damage.
- Purge and cap all sources of alternate fuel – oil and natural gas.
- Demineralized water process equipment must be drained and cleaned.
- Evaluate all chemicals stored on site and eliminate those that will not be used.
- Ensure all fire protection systems are functional and protected from freezing.
- Station batteries must be maintained as normal to provide vital AC to emergency systems and meet North American Electric Reliability Corporation (NERC) procedural requirements.
- Regular inspections must be made to ensure that the idle facility does not become a public nuisance or hazard.

Q. WHAT WERE THE DRIVERS FOR ECONOMIC SHUTDOWN AT BEN FRENCH AND OSAGE?

A. The primary driver is that other units on the Black Hills Power system, as well as economy energy available in the market, are more economical to serve the near-term energy requirements of the customers of Black Hills Power than the Ben French and Osage units. The fact that these units will be retired in 2014 in order to maintain compliance with EPA regulations is also a factor in this decision-making. Because there is little risk that the units will need to be removed from economic shutdown prior to their near-term retirement, it is unlikely that there would be any costs associated with removing them from economic shutdown.

Q. WHAT WILL BE THE IMPACT OF THE ECONOMIC SHUTDOWN?

A. The most significant impact is that customers will see considerable cost savings as a result of the shutdown of Ben French. For example, there are approximately $1.3 million savings in annual operating and maintenance costs resulting from the Ben French shutdown, as shown on Schedule H-14 in the Revenue Requirement Model, and annual energy savings of approximately $1.3 million due to the difference in purchased power costs and the coal costs shown on Schedule H-9 and H-15. The savings on the Osage shutdown have already been generally realized, but the savings were comparable to or perhaps greater than the Ben French savings.

The Black Hills Power system will continue to provide energy to its customers in the most cost effective means possible. Black Hills Power's customers' energy demand will be supplied by existing BHP owned mine mouth coal-fired and natural gas-fired generation, some contracted renewable energy and market power purchases, when economical. The Ben French and Osage units can be reactivated, if needed, until their retirement date of March 21, 2014.

Q. WHAT IS THE STATUS OF NEIL SIMPSON I?

A. Neil Simpson I will remain in operation until its retirement on or before March 21, 2014.

V. MAJOR CAPITAL ADDITIONS

Q. PLEASE DESCRIBE THE COMPANY'S MAJOR CAPITAL ADDITIONS RELATED TO ENVIRONMENTAL REGULATION.

A. The Company has invested approximately $5.2 million in capital additions related to or required by environmental regulations. These capital additions (that have been made since the Company's last rate case) have been placed in service or will be placed in service by April 1, 2013, and are summarized as follows:

Category	Cost	Description
Environmental Regulation	1,100,000	Water treatment Nitrogen Oxides Control
	1,500,000	Wygen III Sulfur Dioxide start-up requirements
	1,100,000	Reciprocating Internal Combustion Engine Compliance for Ben French Diesels
	$1,500,000	Neil Simpson II Stop Valve
TOTAL	$5,200,000	

Q. PLEASE DESCRIBE THE CAPITAL ADDITION RELATED TO WATER TREATMENT REGARDING NITROGEN OXIDES EMISSIONS.

A. The permits for the Neil Simpson complex required a reduction of Nitrogen Oxides (NO_x) emissions for both natural gas-fired and coal-fired generation. In order to comply with the permitting requirements, a reverse osmosis system for the Neil Simpson Complex was purchased and installed in 2009. Cleaner water lowers "water hardness" and can be utilized to control combustion temperature, which in turn leads to lower NO_x emissions. This system makes the site self-sufficient in providing high quality water for process water to operate the Steam Generators that provide emission compliance with Nitrogen Oxides permit limits. This capital addition benefits various generating plants at the Neil Simpson Complex and is a shared asset based upon capacity. The portion of the capital cost attributed to the Company is $1.1 million.

Q. PLEASE EXPLAIN THE CAPITAL ADDITION TO WYGEN III REGARDING SULFUR DIOXIDE EMISSIONS.

A. The air permit for Wygen III requires compliance with a three-hour sulfur dioxide emission limit once firing commenced. In other words, there are emission limits during the start up of the Wygen III generating plant. Due to environmental pressures on coal plant emissions, the State of Wyoming issued the air permit in 2008 but included, for the first time in Wyoming, start-up emission limits. These start-up limits were required to ensure current federal standards were met, thus allowing the State to issue the coal plant air permit while ensuring compliance with federal standards. Working with the original equipment manufacturer (OEM) to procure process equipment to meet these new start-up limits required us to agree to a test period for which the OEM could collect data and ensure a reliable design to achieve these "new to industry" start-up limits. Therefore, a temporary facility was put in place complying with these start-up limitations. The test facility provided sufficient data and design details for the OEM to design and construct a permanent facility, which will be in service by April 2013. This permanent facility allows for the injection of hydrated lime, which will allow Wygen III to meet the requirement of its air permit regarding the three-hour sulfur dioxide emission start-up limits with a fully integrated, OEM warranted and designed system.

Q. PLEASE EXPLAIN THE CAPITAL ADDITIONS REGARDING THE BEN FRENCH DIESELS.

A. The Ben French diesels, located in Rapid City, South Dakota, and built in 1965, are internal combustion engines and subject to new EPA requirements limiting emissions of carbon monoxide from reciprocating internal combustion engines. Therefore, modifications that are expected to be completed in the first quarter 2013 are being made to the Ben French diesels to add catalysts that convert carbon monoxide to carbon dioxide. The modifications made to the Ben French diesels are not unlike adding a catalytic converter to an automobile. These capital additions will provide for compliance by the May 13, 2013 deadline of the most current EPA National Emissions Standards for Hazardous Air Pollutants.

Q. PLEASE DESCRIBE THE INVESTMENT IN THE NEIL SIMPSON II STOP VALVE.

A. The Company invested $1.5 million for the replacement of a combination stop valve/control valve in Neil Simpson II. This combination valve was placed in service in May 2012.

Q. WHY WAS IT NECESSARY TO REPLACE THIS COMBINATION VALVE ON NEIL SIMPSON II?

A. NERC and the applicable balancing authority, reliability council and reserve group, require utilities to maintain spinning reserves, which generally defined, means that the utility must have reserves available within ten minutes to regulate load. Some of these reserves are required to be on line or referred to as "spinning reserves".

As I noted previously, Neil Simpson I, Osage and Ben French are subject to EPA Area Source Rules, and as a result, the Company has determined that these three generating facilities must be retired no later than March 21, 2014, the EPA deadline for compliance. Furthermore, Osage and Ben French have been placed in economic shutdown.

Osage and Ben French previously were run at reduced loads in order to provide spinning reserves. But those spinning reserves are no longer available because of the economic shutdown and will be permanently unavailable for spinning reserves after March 21, 2014 because of the EPA's Area Source Rules. Therefore, the Company determined that Neil Simpson II, if retrofitted with a new combination valve, offered the best alternative for the Company's spinning reserves requirement. The Company determined that the cost benefit of purchasing spinning reserves from the market, while possible, would be an unacceptable risk in a fluctuating market. The timing of the combination valve retrofit coincided with the regularly scheduled major maintenance outage of Neil Simpson II.

Without this retrofit, Neil Simpson II did not qualify for spinning reserves. With the addition of the new combination valve, the plant is now available to provide spinning reserves. The unit has now successfully completed the NERC-required response testing and complies with the ten-minute response requirements to be certified for spinning reserves.

Q. **PLEASE DESCRIBE THE COMPANY'S MAJOR CAPITAL ADDITIONS RELATED TO GENERATION EFFICIENCY AND RELIABILITY.**

A. The Company has invested approximately $20.3 million in capital additions related to generation efficiency and reliability. These capital additions (that have been made since the Company's last rate case) have been placed in service or will be placed in service by April 1, 2013, and are summarized as follows:

Category	**Cost**	**Description**
Generation Efficiency/Reliability	$8,500,000	Neil Simpson II Air-Cooled Condenser
	2,800,000	Wyodak Air-Cooled Condenser
	2,100,000	Generation Transformer – Neil Simpson II
	750,000	Spare Transformer
	570,000	Wyodak Plant – spare transformer
	5,600,000	Overhauls/Turbine/Boiler
TOTAL	$20,320,000	

Q. PLEASE DESCRIBE THE CAPITAL ADDITION RELATED TO THE NEIL SIMPSON II AIR-COOLED CONDENSER.

A. Neil Simpson II was originally constructed in 1995 and has an air-cooled condenser. Nevertheless, this plant was not able to run at a maximum rating if the ambient temperature was greater than 77 degrees. Specifically, unit derates were required during warm temperature months due to elevated back pressure. As a result, Neil Simpson II was not able to run at its maximum rating during high demand or peak times. In 2009, the Company expanded the air-cooled condenser surface area on Neil Simpson II, which allowed the unit to operate more efficiently during warm temperature months, using less fuel per MW generated. Neil Simpson II may now operate at its full maximum rating up to 92 degrees ambient temperature, rather than the original 77 degrees ambient design operating temperature.

Q. PLEASE DESCRIBE THE CAPITAL ADDITIONS COMPLETED REGARDING THE WYODAK GENERATION FACILITY.

A. The air-cooled condenser in the Wyodak generation plant, which was installed in 1978, reached the end of its useful life and needed to be replaced. This air-cooled condenser was replaced at a total cost of approximately $14 million and was placed in service in 2011. The Company's share of 20% of that cost, or $2.8 million, is included in rate base as a capital addition.

Q. PLEASE EXPLAIN THE CAPITAL ADDITION REGARDING THE NEIL SIMPSON II TRANSFORMER.

A. In June 2012, the Neil Simpson II generator step up ("GSU") failed, resulting in a three-week outage. A suitable replacement was identified, purchased and installed by July 1, 2012, at a cost of $2.1 million.

Q. HAS THE COMPANY DECIDED TO ACQUIRE A SPARE TRANSFORMER FOR NEIL SIMPSON II?

A. Yes. The Company received an estimate of $750,000 to repair the main GSU transformer that was removed from Neil Simpson II ("Spare Transformer") and has authorized the repair of that transformer. The repairs on the Spare Transformer will be completed on or before April 1, 2013. The Company has determined that acquiring a spare transformer at a reasonable cost is relatively low-cost risk mitigation compared to the cost of purchased power if the new transformer were to fail. The spare transformer will serve as a spare in case of a loss of a transformer on the Black Hills Power system, and not just on Neil Simpson II. This provides for an additional measure of reliability for the Company's customers.

Q. PLEASE DESCRIBE THE WYODAK PLANT SPARE TRANSFORMER.

A. Pacificorp, which controls the management of the Wyodak plant, decided to purchase a new main GSU transformer to be used as a spare for the Wyodak plant. Black Hills Power paid $570,000 towards the cost of this spare transformer. The transformer is stored at the Wyodak plant.

Q. ARE SPARE TRANSFORMERS NECESSARY?

A. Yes, if a reliable spare transformer can be acquired at a reasonable cost. The three-week outage resulting from the failure of the Neil Simpson II transformer could have been significantly longer. In the industry, it often takes up to six months to identify, purchase and replace a transformer. An outage can be expensive for a utility, particularly if the outage occurs during high demand or peak times. Pacificorp's decision to purchase a spare transformer for the Wyodak plant validates the Company's decision to have a spare transformer available for its power system.

Q. PLEASE DESCRIBE THE COMPANY'S CAPITAL ADDITIONS MADE FOR OVERHAULS OF ITS GENERATION FLEET.

A. Every plant in Black Hills Power's generation fleet undergoes regular maintenance. Overhauls are scheduled periodically. Such plant overhauls are comparable to rotating tires on your automobile or changing the oil and air filter. These costs are reflective of replacement components for Wyodak and other Black Hills Power's generation assets. The Company's investments in overhauls totaled approximately $5.6 million and were completed from 2008 to 2010.

VI. STAFFING IMPACTS

Q. PLEASE DESCRIBE STAFFING PLANS AT BEN FRENCH.

A. When Ben French went into economic shutdown, all employees were retained for a month to make the modifications necessary to effectuate the economic shutdown. On October 1, 2012, staffing was reduced by seven individuals with eleven staff remaining to cover the 24 hours a day and 7 days a week operations of the natural gas-fired peaking units that remain at the Ben French and Lange sites. This remaining staff includes management and supervision. Some of the seven employees were relocated as staff at the Neil Simpson Power Plant in Gillette, Wyoming. Others will be retiring effective June, 2013. This adjustment is reflected in the Revenue Requirement Model, Schedule H-14. Please refer to Ms. Wentz's direct testimony.

VII. CHEYENNE PRAIRIE GENERATING STATION

Q. WHAT IS THE LONG-TERM PLAN FOR ADDRESSING THE CAPACITY NEEDS OF CUSTOMERS RESULTING FROM THESE EPA-MANDATED REGULATIONS REQUIRING PLANT RETIREMENTS?

A. Black Hills Power, along with Cheyenne Light, Fuel and Power Company ("Cheyenne Light"), are developing the Cheyenne Prairie Generating Station (CPGS) in Laramie County, Wyoming. Black Hills Power's ownership in this facility will replace the reductions in its generation fleet as a result of the new EPA requirements discussed earlier in my testimony.

Q. PLEASE GENERALLY DESCRIBE THE CHEYENNE PRAIRIE GENERATING STATION (CPGS).

A. The CPGS will include (2) two natural gas-fired combustion turbine generators (CTG's) and (1) one steam turbine in combined cycle (CC), with a total base load nominal net output of 95 MW. This 2 x 1 CC will be jointly owned 42% by Cheyenne Light and 58% by Black Hills Power and therefore CPGS will provide

Black Hills Power with 55 MW. CPGS also includes a simple cycle CTG owned by Cheyenne Light with a net output of 37 MW.

Q. HAS THE WYOMING PUBLIC SERVICE COMMISSION ISSUED A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF CPGS?

A. Yes. Cheyenne Light and Black Hills Power filed a joint application for a Certificate of Public Convenience and Necessity (CPCN) for the CPGS in November 2011 with the Wyoming Public Service Commission. A CPCN was granted by the Wyoming Public Service Commission. Construction is scheduled to begin during the first quarter of 2013.

Q. ARE THERE ANY COSTS IN THIS RATE CASE RELATED TO CPGS?

A. No.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.