Direct Testimony
Vance Crocker

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. EL14-___

March 31, 2014

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Exhibits

None

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Vance Crocker. My business address is 409 Deadwood Avenue, Rapid City, South Dakota 57702.

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

A. I am the Vice President, Electric Operations, for 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. BRIEFLY DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I graduated from South Dakota State University, Brookings, South Dakota, in 1990 with a Bachelor of Science Degree in Electrical Engineering. I am currently a Registered Professional Engineer in the State of South Dakota. I was hired by Black Hills Power and Light upon graduation and have been employed with the Company since that time. The following is a summary of positions I have held with the Company.

From 1990 to 2000, I worked as an Engineer responsible for the planning and design of a wide array of transmission and distribution projects. From 2000 to 2005, I was a Transmission Planning Engineer responsible for developing long-range transmission plans that ensure reliability of the transmission system. From 2005 to 2007, I was the Manager of Transmission Planning and Operations. In this role I was responsible for transmission planning and managing the 24/7 Reliability Dispatch Center for Black Hills Power and its sister utility Cheyenne Light, Fuel and Power Company ("Cheyenne Light"). From 2007 to 2011, I was Director, Transmission Services for Black Hills Corporation's ("BHC") three electric utilities, Black Hills Power, Cheyenne Light, and Black Hills/Colorado Utility Company, LP. In this role, I was responsible for the transmission planning function and for the 24/7 Reliability Dispatch Center. From 2011 to 2013, I was the General Manager, Black Hills Energy – Kansas Gas. As General Manger, I was responsible for leading and managing Black Hills Energy for the State of Kansas. In 2013, I was named the Vice President of Electric Operations, Black Hills Power. I continue in this role today.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS BLACK HILLS POWER'S VICE PRESIDENT OF OPERATIONS.

A. I am responsible for the financial and operational performance of Black Hills Power's electric operations. I directly oversee operating functions, including electric distribution network operations, maintenance, construction, local customer service, customer relations and community relations. I am indirectly involved in the oversight of certain other functions that are centralized within BHC. Examples of central functions include regulatory and legislative affairs, human resources, IT, and customer service call center functions.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide: 1) an overview of this rate case; 2) an overview of Black Hills Power's operations and business in South Dakota; 3) a summary of Black Hills Power's reliability metrics and customer service efforts; 4) an overview of the Winter Storm Atlas driven ground patrol program; 5) a discussion regarding Black Hills Power's workforce; and 6) an introduction of the other witnesses testifying in this proceeding.

III. RATE CASE OVERVIEW

Q. WHAT ARE THE PRIMARY REASONS FOR THIS RATE CASE?

A. There are four primary reasons for this rate case. The first is the request that Cheyenne Prairie Generating Station ("CPGS") be added to rate base, coinciding with the in-service date of CPGS, and to add certain costs and expenses associated with CPGS as adjustments to the test year. Second, Black Hills Power will make significant investments in capital projects necessary to maintain, improve and replace infrastructure on our system. Third, as a result of the Environmental Protection Agency's ("EPA") Area Source Rules, Black Hills Power requests recovery of the costs related to the decommissioning of three of its coal-fired generation facilities. Fourth and finally, Black Hills Power requests recovery of the costs incurred to repair damage and restore service to its customers as a result of Winter Storm Atlas.

Q. WHAT IS THE AMOUNT OF THE REQUESTED INCREASE IN RATES?

A. As illustrated throughout the testimony offered in this docket, Black Hills Power has expended costs to ensure its continued ability to provide safe and reliable service in South Dakota. Black Hills Power requests authority to increase its annual revenue by $14,634,238 to cover the costs incurred since its last rate case.

Q. WHAT IS CPGS?

A. CPGS, which is located in Cheyenne, Wyoming, will consist of a 95 MW combined-cycle combustion turbine jointly owned by Black Hills Power (55 MW) and its sister utility Cheyenne Light (40 MW) and a 37 MW simple-cycle combustion turbine owned entirely by Cheyenne Light. Construction of CPGS began in April 2013, and is expected to be completed and in-service by October 1, 2014. CPGS is described in more detail in the testimony of Mark Lux.

Q. WHAT ARE THE CAPITAL EXPENDITURES RELATED TO CPGS?

A. The construction of CPGS is in progress as of the date of this application. There is an agreed upon cost cap of $222 million for all of the facilities at CPGS, and construction costs are expected to be at or below this amount. Black Hills Power's portion of the cost of construction of CPGS is expected to be approximately $93 million.

Q. BEYOND CPGS, WHAT ARE THE OTHER MAJOR CAPITAL ADDITIONS THAT ARE INCLUDED IN THIS RATE CASE?

A. There are a number of capital plant investments that have been made to existing generation since Black Hills Power's last South Dakota rate case. In particular, Black Hills Power has made major capital investments for safety and security, control system upgrades, environmental issues, integrity and reliability, regulatory requirements and facilities. Each of these categories of capital plant investments are discussed in detail in the testimony of Mark Lux.

In addition, Black Hills Power has also made capital investments to its distribution assets since its last rate case. For additional discussion regarding these investments, please refer to the testimony of Mike Fredrich.

Q. PLEASE EXPLAIN WHY BLACK HILLS POWER PLANS TO DECOMMISSION THREE OF ITS COAL-FIRED GENERATION FACILITIES.

A. The EPA enacted the National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers ("Area Source Rules"), which is designed to reduce emissions of hazardous air pollutants from various small boilers, to include coal-fired units of 25 MW or less. Black Hills Power owns three coal-fired power plants equipped with boilers of 25 MW or less and therefore subject to the Area Source Rules: Neil Simpson I, Osage, and Ben French. The implications of the standards set forth in the Area Source Rules require either the retrofit of expensive new environmental controls on these three facilities or the retirement of the affected units. Black Hills Power has concluded that the most cost effective plan for its customers to achieve EPA compliance was to retire Neil Simpson I, Osage, and Ben French. Decommissioning is discussed in more detail in the testimony of Mark Lux.

Q. PLEASE EXPLAIN WHY BLACK HILLS POWER IS REQUESTING RECOVERY OF COSTS ASSOCIATED WITH WINTER STORM ATLAS.

A. From Thursday, October 3rd through Saturday, October 5th 2013, western South Dakota experienced a severe winter storm that is commonly referred to as Winter Storm Atlas. Winter Storm Atlas has been determined to be the second heaviest snowstorm on record for Rapid City. Heavy snow and high winds caused significant damage to trees and power lines in the affected areas and caused treacherous travel and working conditions. Because the storm occurred in early October all deciduous trees were fully leafed. The combination of the leafed trees, heavy snow and high winds resulted in extensive broken trees that contributed greatly to the damage to Black Hills Power's facilities throughout its service territory in South Dakota.

Black Hills Power considers the outages caused by Winter Storm Atlas to be the worst in the Company's 130 year history. At the outage peak, approximately 41,800 of Black Hills Power's customers (in excess of 60%) were without power. Internal personnel as well as personnel dispatched from utilities in neighboring states supported Black Hills Power's restoration effort. These crews averaged 13 to 16 hour days with an exemplary safety record during the restoration period. At the height, these restoration efforts were carried out by over 500 employees and contractors. Many of the crews came from other states including North Dakota, Montana, Wyoming, and Colorado. Because Black Hills Power had an appropriate emergency response plan and began executing this plan prior to the storm, including timely activation of resources, it was able to restore power to 95% of its customers in six days.

The volume of personnel, materials and equipment that were mobilized for this storm was unprecedented, and critical to the Company's success. The resources that were utilized were greatly needed and resulted in power being restored to customers dramatically sooner than otherwise would have been possible. Repairing the substantial and widespread damage was costly, and far exceeded average annual storm-related costs. As a result, Black Hills Power seeks recovery of the associated costs in this proceeding. For additional information regarding the costs attributed to Winter Storm Atlas, please see the testimony of Chris Kilpatrick.

Q. WHAT INNOVATIVE MEASURES HAS BLACK HILLS POWER UNDERTAKEN TO MITIGATE INCREASING COSTS AND RATE IMPACT?

A. Black Hills Power supported and received approval for the phase in rate plan ("PIPR") whereby customers would pay construction financing costs during construction instead of adding an allowance for funds used during construction to rate base. The PIPR that accomplished this resulted in savings for Black Hills Power customers. The PIPR also provided that customers pay quarterly increases during the construction of CPGS, which minimizes the customer impact of the new generation going into customer rates on October 1, 2014.

Q. WHAT OTHER MEASURES WERE UNDERTAKEN BY BLACK HILLS POWER?

A. The electricity needs of the customers of Black Hills Power continue to steadily increase. Generation facilities must be built in advance to ensure the continued reliability of service to its customers. At the same time, Black Hills Power must decommission three of its coal-fired generation units. In addressing these issues, Black Hills Power identified the opportunity to partner with its sister utility, Cheyenne Light, in the development and joint ownership of the CPGS. This partnership provides for economies of scale that reduce overall costs, including the joint ownership of assets that benefit both utilities.

IV. BUSINESS OVERVIEW OF BLACK HILLS POWER

Q. PLEASE BRIEFLY DESCRIBE BLACK HILLS POWER'S HISTORY.

A. Black Hills Power and its predecessor companies have been providing electric power to the Black Hills region since 1883, when Pilcher Electric Light Co. was formed by early pioneers in Deadwood, SD. Black Hills Power and Light was formed in 1941 through the purchase and combination of several existing electric utilities throughout the Black Hills. Headquartered in Rapid City, today, Black Hills Power is a wholly owned subsidiary of BHC.

Q. PLEASE GIVE A BASIC OVERVIEW OF BLACK HILLS POWER'S BUSINESS OPERATIONS.

A. Black Hills Power is a regulated electric utility engaged in the generation, transmission and distribution of electricity to approximately 68,000 customers in western South Dakota, northeastern Wyoming, and southeastern Montana. Black Hills Power's service territory covers approximately 9,300 square miles. The Company has approximately 265 current employees with several open positions, and is further supported by Black Hills Service Company, LLC ("Service Company") and Black Hills Utility Holdings, Inc. ("Utility Holdings"). Approximately 90 percent of Black Hills Power's retail electric revenues during the 12 months ending September 30, 2013 were generated in South Dakota.

Q. PLEASE DESCRIBE BLACK HILLS POWER'S UTILITY ASSETS.

A. The assets utilized by Black Hills Power to provide service to customers fall into three primary classes: Generation (also known as Production), Transmission and Distribution. Each of these asset classes are described in more detail below.

<u>Generation Assets</u>

Black Hills Power's current ownership interests in electric generation plants are as follows:

Unit	Fuel Type	Location	Ownership Interest (%)	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

However, as a result of the newly enacted Area Source Rules, Black Hills Power retired three of its coal-fired generation units, Osage, Ben French, and Neil Simpson I.

In addition to the balance of the ownership of the remaining generation facilities, Black Hills Power will also own 58% of a combined cycle unit at CPGS. This unit will be in service on October 1, 2014, and will provide a total of 95 MW of generating capacity, with Black Hills Power owning 55 MW.

<u>Transmission Assets</u>

Black Hills Power's electric transmission system is composed of approximately 590 miles of high voltage (230 kV) transmission lines and 500 miles of low voltage (69 kV and 47 kV) transmission lines.

Black Hills Power also owns 35 percent of a transmission tie that interconnects the Western and Eastern transmission grids, which are independently operated transmission grids serving the western United States and eastern United States, respectively. This transmission tie, which is 65 percent owned by Basin Electric, provides transmission access to both the Western Electricity Coordinating Council region in the West and the Mid-Continent Area Power Pool region in the East. This transmission tie allows Black Hills Power to buy and sell energy on the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids.

Distribution Assets

Black Hills Power owns and operates 2,550 line miles of distribution facilities. Additional distribution assets include poles, transformers, meters, and other related equipment.

Q. PLEASE PROVIDE A BREAKDOWN OF BLACK HILLS POWER'S CUSTOMER CLASSES AND CUSTOMER COUNTS.

A. From October 2012 through September 2013, Black Hills Power provided service to the following average number of retail customers in South Dakota by customer class.

South Dakota Retail Customers

Residential	52,450
Small General Service	11,886
Large General Service	505
Lighting	647
Total	65,487

Q. WHAT ARE BLACK HILLS POWER'S HIGHEST SUMMER AND WINTER PEAK LOADS?

A. Black Hills Power's all-time peak load of 452 megawatts was reached in July, 2011, and a winter peak load of 408 megawatts was reached in January, 2011.

Q. PLEASE IDENTIFY BLACK HILLS POWER'S LONG TERM WHOLESALE CONTRACTS.

A. Black Hills Power has long term agreements to serve Sheridan, Wyoming (through Montana-Dakota Utilities Company) and the Municipal Energy Agency of Nebraska, also known as MEAN.

V. <u>RELIABILITY AND CUSTOMER SERVICE</u>

Q. PLEASE DESCRIBE HOW BLACK HILLS POWER MEASURES RELIABILITY OF ITS DELIVERY SYSTEM.

A. Black Hills Power utilizes generally accepted reliability indices, as defined by the Institute of Electrical and Electronic Engineers ("IEEE") in its standard number 1366-2003, "Guide for Electric Power Distribution Reliability Indices." Generally speaking, the most often used performance measurement for a sustained interruption is the System Average Interruption Duration Index ("SAIDI"). SAIDI measures the duration of an interruption for an "average time" customers are interrupted during a given time period. Other standard measures are utilized to help target expenditures for capital improvements to improve reliability measures.

Q. PLEASE DESCRIBE BLACK HILLS POWER'S HISTORICAL RELIABILITY PERFORMANCE.

A. Black Hills Power participates in an annual reliability benchmarking study conducted by IEEE. Among the 60 participating utilities, Black Hills Power consistently ranks as one of the top 25 percent most reliable companies. The following table sets forth a summary of Black Hills Power's performance relative to the IEEE benchmark survey for the years 2009, 2010, 2011, and 2012.

SAIDI Performance

(Average annual customer outage duration in minutes)

	2009	2010	2011	2012
Black Hills Power	69.9	76.1	85.9	72.6
IEEE Top Quartile	81.2	89.5	100.7	93.1

At the time of this filing, 2013 survey data is not yet available from IEEE.

Based on 2012 data, Black Hills Power customers had, on average, power available 99.99 percent of the time.

Q. WHAT EMPHASIS DOES BLACK HILLS POWER PLACE ON CUSTOMER SERVICE SATISFACTION LEVELS?

A. Customer service has been and remains a very high priority for Black Hills Power, and for all employees within the Black Hills Power utility. Company and departmental goals include a customer satisfaction component.

Q. DOES BLACK HILLS POWER CONSISTENTLY MEASURE CUSTOMER SERVICE AND SATISFACTION LEVELS?

A. Yes. Black Hills Power believes that its focus on customer service is reflected well in its ability to maintain a high level of customer satisfaction, as demonstrated by the results of surveys completed by J.D. Powers and Associates. For each set of results (conducted approximately each quarter), Black Hills Power's customer satisfaction scores have consistently exceeded the average of Midwest utilities participating in the surveys. The following table sets forth a summary of Black Hills Power's performance relative to other midsize Midwest utilities participating in JD Power surveys for the years 2010, 2011, 2012 and 2013.

JD Power Overall Customer Satisfaction Index

	2010	2011	2012	2013
Black Hills Power	601	637	644	671
Midwest Region	637	618	627	639

Q. PLEASE DISCUSS BLACK HILLS POWER'S CONSOLIDATION OF ITS CUSTOMER SERVICE AND LINE OPERATION DEPARTMENTS AT SEVERAL LOCATIONS.

A. Black Hills Power consolidated its customer service and line operation departments at several offices to adapt to changing customer needs, including customers' preference to use more technology and more convenient payment options when doing business with the Company. As a result of these changing trends, the Company has experienced a 45% decrease in walk-in traffic in recent years, while online interactions have increased by 40%.

To better serve the current customer preferences and reduce costs for all customers, the Company implemented a new customer service model on February 3, 2014. As part of the new model, three regional customer service and operations centers will be utilized to offer expanded services in South Dakota. These regional centers are located in Sturgis and Spearfish to serve the Northern Hills region, and Custer to serve the Southern Hills region. The Rapid City Service

Center will continue to serve the Rapid City area. Offices in Deadwood and Hot Springs were closed to walk-in customer service traffic, but continue to serve as operations centers. Offices in Newell and Belle Fourche were closed. The new regional model continues to offer walk-in payment options for those customers preferring this method, and provides for an increased focus on delivering a wider variety of services to customers.

Q. PLEASE DESCRIBE BLACK HILLS POWER'S ENHANCED AND EXPANDED CUSTOMER SERVICE MODEL.

A. As a result of its conversion to the CIS+ information system that is now common to the regulated utilities of BHC, Black Hills Power is able to provide call center customer service support 24 hours a day, 7 days a week in the case of electric emergencies. General customer support through the Call Centers is provided 6 days a week from 7am-8pm Monday through Friday and 8am to 5pm on Saturday, mountain time. In addition, business process initiatives have been put into place to improve customer service as well as efficiencies. For example, additional payment options are available through our electronic bill presentment software and mobile application or Quick Response code (QR) for customers wishing to pay their bill via their smart phone. An improved interactive response system provides self-service options for customers who do business with the Company, including the ability to make payment arrangements, set up their accounts on budget billing, initiate payments and report service interruptions. With the installation of Automated Meter Infrastructure, Black Hills Power customers can view their monthly, weekly and daily electric usage patterns from our website as well as service interruption updates. Black Hills Power has also initiated outage and other Company news on social media. The website has been redesigned to offer customers the ability to access their account information from various electronic devices including tablets and smart phones. Finally, Black Hills Power continues to provide and enhance energy efficiency programs to assist customers with managing their energy bill.

Q. HOW DOES BLACK HILLS POWER DEMONSTRATE ITS COMMITMENT TO THE COMMUNITIES AND CUSTOMERS IT SERVES?

A. As a community partner, Black Hills Power remains active in numerous civic and community matters and economic development efforts. Black Hills Power has been involved in a broad range of projects to improve its local communities. In Black Hills Power's South Dakota service area, some examples of this involvement include participation in local Community United Way campaigns, annual participation in the United Way Day of Caring, board involvement on numerous community and civic organizations, extensive involvement in Chamber of Commerce and economic development in the communities served by the Company, Power of Trees tree planting programs, and participation in numerous K-12 safety education and career development programs.

Q. DOES BLACK HILLS POWER PROVIDE ENERGY EFFICIENCY INCENTIVES TO ITS CUSTOMERS?

A. Yes. Black Hills Power provides various Energy Efficiency incentives to its customers in South Dakota. For example, the Company offers rebates for energy efficient water heaters and heat pumps. Additional programs include home energy audits, refrigerator recycling, residential home weatherization, commercial and industrial rebates, program training and marketing and reporting services.

Q. DOES BLACK HILLS POWER SUPPORT COMMUNITY PROGRAMS FOR ENERGY ASSISTANCE?

A. Yes. Black Hills Power supports community programs for energy assistance primarily through our Black Hills Cares program and the Walk for Warmth program. Our Black Hills Cares program offers customers and employees several options to donate to the Black Hills Cares fund, and all customer contributions are matched by Black Hills Power dollar for dollar. The Walk for Warmth program is an annual walk initiated by Black Hills Power where all entry fees and donations directly support the Black Hills Cares program and all funds are matched dollar for dollar by Black Hills Power. The 2014 Walk for Warmth raised over $20,000 for this important program. Funds from the Black Hills Cares program are administered for those in need by Church Response, the Salvation Army and the Ministerial Association.

VI. <u>GROUND PATROL PROGRAM</u>

Q. PLEASE EXPLAIN WHY BLACK HILLS POWER IS PERFORMING A GROUND PATROL OF ITS ENTIRE DISTRIBUTION SYSTEM IN SOUTH DAKOTA.

A. As indicated above, the Black Hills Region experienced a devastating winter storm in October of 2013. The combination of the leafed trees, heavy snow, and high winds resulted in extensive broken trees that contributed greatly to the damage to Black Hills Power's facilities throughout its service territory in South Dakota. Although significant efforts to repair facilities and address vegetation were undertaken in conjunction with the restoration efforts that followed the storm, Black Hills Power continues to discover damaged vegetation and facilities today. In order to identify latent defects and to ensure a safe, reliable system, the Company has determined that it is prudent to perform a system wide ground patrol of the electrical system that is located in the Black Hills region.

Q. WHAT DOES A GROUND PATROL ENTAIL?

A. A ground patrol consists of a visual inspection of a power line and supporting infrastructure performed by someone either on foot or in a vehicle. Individuals performing ground patrols are trained to spot potential defects or other concerns that may impact the ability to safely and reliably deliver power to customers.

Q. HOW DOES BLACK HILLS POWER PLAN TO ACCOMPLISH THIS TASK?

A. The Company has retained DCP Consulting to perform the majority of the ground patrol efforts within Black Hills communities. Black Hills Power employees will perform ground patrols in remote areas of the Black Hills and on the majority of the 69kV system. Black Hills Power plans to have the majority of the ground patrols completed by June of 2014.

Q. WHAT ARE THE COSTS ASSOCIATED WITH THIS PROJECT?

A. Black Hills Power estimates that the project will cost approximately $1.1 million. For information regarding the costs contained within this estimate and the proposed treatment of those costs, please refer to the testimony of Jon Thurber and Chris Kilpatrick.

Q. WHAT MEASURES HAS BLACK HILLS POWER TAKEN TO MITIGATE THE COSTS ASSOCIATED WITH THIS PROJECT?

A. Black Hills Power developed a scope of work for the ground patrol project and solicited bids from multiple qualified vendors. The low bidder was selected for the project. Training was held with both employees and the contractor to ensure each inspector understood the scope of work and the process for reporting potential issues. An electronic database was created to improve efficiency with tracking items identified in the patrol and the associated repairs.

VII. BLACK HILLS POWER'S WORKFORCE

Q. PLEASE DESCRIBE BLACK HILLS POWER'S CURRENT WORKFORCE.

A. As stated above, Black Hills Power currently employs approximately 265 people with several open positions. In addition, employees of Service Company and Utility Holdings perform specific functions for Black Hills Power.

Q. DO YOU FORESEE ANY CHANGES TO BLACK HILLS POWER'S WORKFORCE IN THE NEAR TERM?

A. Yes. The average age of Black Hills Power's employees is 47.1 years. Over the next 8 years, approximately 31% of Black Hills Power's current workforce will reach the age of 62, which has been the historical average age of retirement at Black Hills Power and its parent, BHC.

Q. DOES THIS CAUSE ANY CONCERN?

A. Absolutely. Our people are our best assets. A talent shortage within our organization impairs our ability to provide safe, reliable service to our customers. The impending retirements are a concern not only from a headcount perspective, but from a knowledge and experience standpoint. Black Hills Power understands that over the next eight years, employees representing a combined 1,713 years of work experience are expected to retire. This represents approximately 50% of total years of experience. Black Hills Power has not experienced this significant type of loss of experience in its history. Not having replacements ready for our retiring employees could put Black Hills Power at risk by placing undue strain on our remaining employees, who must train replacements as well as complete their own duties.

Q. WHAT STEPS HAVE THE COMPANY TAKEN TO ADDRESS THIS CONCERN?

A. Black Hills Power completed a strategic workforce planning process that evaluates workforce demographics, tenure, experience and skill capabilities as well as industry trends and risks. As a result of this process, the Company has retained employees that were employed at the retired Neil Simpson I facility. Also as a result of this process, the Company has identified a total of 72 potential retirements between now and the end of 2021 and is therefore seeking to add several positions through its proposed FutureTrack Workforce Development Program. For additional information on these topics, please refer to the testimony of Chris Kilpatrick and Jennifer Landis.

Q. WHAT OPERATIONS POSITIONS ARE INCLUDED IN BLACK HILLS POWER'S FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM?

A. Constructions representatives, electricians, meter mechanics and line mechanics are the four operations positions that are included in the FutureTrack Workforce Development Program.

Q. PLEASE EXPLAIN WHY THESE POSITIONS ARE INCLUDED.

A. In the next eight years, Black Hills Power expects 3 construction representatives, 5 electricians, 3 meter mechanics and 13 line mechanics to retire. Based on the

Company's experience, it takes approximately 2 years to fully train a construction representative, 4 years to fully train an electrician, 2 years to fully train a meter mechanic and 4 years to fully train a line mechanic. Due to the lengthy training periods and the expected shortage of skilled candidates, these four operations positions are included in the Black Hills Power FutureTrack Workforce Development Program.

Q. HOW PRODUCTIVE ARE THE INDIVIDUALS WHO ARE TRAINING FOR THESE POSITIONS?

A. Based on the Company's experience, a construction representative is 50 percent productive after 12 months of training, and able to work independently after 2 years of training; an electrician is 75% percent productive after 3 years of training, and able to work independently after 4 years of training; a meter mechanic is 25% productive after 6 months of training and able to work independently after 2 years of training; and a line mechanic is 75 percent productive after 3 years of training, and able to work independently after 4 years of training. Jennifer Landis discusses how these productively metrics are applied to determine what portion of a particular position is charged to the FutureTrack Workforce Development Program regulatory asset.

VIII. INTRODUCTION OF WITNESSES

Q. PLEASE INTRODUCE BLACK HILLS POWER'S OTHER WITNESSES IN THIS PROCEEDING.

A. The other witnesses providing written direct testimony and exhibits, and the subject matter of each, are listed below:

Kyle D. White, Vice President of Regulatory Affairs

Mr. White discusses the corporate structure of Black Hills Power and its parent company, BHC. He discusses the class cost of service and proposed rates. He also discusses the Statement R coal pricing and presents the business case for utility-owned generation. Lastly, he supports the decision to construct CPGS.

Jill S. Tietjen, President and CEO of Technically Speaking, Inc.

Ms. Tietjen demonstrates the need for a new resource on the Black Hills Power system in the 2014 timeframe. She discusses the 2011 Integrated Resource Plan that was conducted to determine how Black Hills Power's resource need should be fulfilled. She discusses the CPGS as the resource to be installed in 2014.

Mark Lux, Vice President and General Manager, Regulated and Non-Regulated Generation

Mr. Lux describes CPGS and its construction costs, plant operations and maintenance. He provides an overview of the major capital plant investments that are included in this rate case and defines major maintenance. He discusses the decommissioning of the Neil Simpson I, Osage, and Ben French coal-fired generation facilities. He summarizes the Neil Simpson Complex common asset treatment and addresses plans for the Neil Simpson labor force. Lastly, Mr. Lux addresses the generation related positions that are included in the FutureTrack Workforce Development Program.

Kent J. Kopetzky, Senior Manager, Gas Supply Services

Mr. Kopetzky describes the natural gas supply, pipeline capacity, and other fuel cost for CPGS.

Mike Fredrich, Director Engineering Services

Mr. Fredrich describes Black Hills Power's service territory. He summarizes major capital distribution investments. He also discusses Black Hills Power's LIDAR project.

Jennifer Landis, Director Corporate Human Resources and Talent Management

Ms. Landis describes the FutureTrack Workforce Development Program for Black Hills Power.

Laura A. Patterson, Director of Compensation, Benefits, and Human Resources Information Services

Ms. Patterson describes the compensation and benefits philosophy of Black Hills Power.

Jon Thurber, Manager - Regulatory Affairs

Mr. Thurber supports and explains the revenue requirement model for Black Hills Power and discusses the test year rate base and income statement, describes the appropriate adjustments to the test year rate base, revenues and operating expenses, including any known and measurable or contracted for adjustments, and supports the requested revenue increase.

Christopher J. Kilpatrick, Director Regulatory

Mr. Kilpatrick supports Black Hills Power's revenue requirement. He discusses the Phase In Plan Rate revenue. He addresses the CPGS pipeline cost allocations. He summarizes the proposed changes to the Energy Cost Adjustment. He addresses the treatment of the decommissioning and Winter Storm Atlas regulator assets. Lastly, he discusses the Cost Allocation Manuals.

Charles R. Gray, Manager – Regulatory Affairs

Mr. Gray provides the proof of test year revenues and billing determinants for Black Hills Power. Mr. Gray also discusses the jurisdictional cost of service.

John J. Spanos, Vice President of Gannett Fleming

Mr. Spanos supports Black Hills Power's proposed depreciation expense rates.

Brian G. Iverson, Vice President, Treasurer

Mr. Iverson certifies the books and records of Black Hills Power and the use of the FERC uniform system of accounts. In addition, Mr. Iverson discusses the corporate finance philosophy of Black Hills Power, the proposed capital structure, long term debt and the cost of equity and debt financing activity.

Dr. William E. Avera of FINCAP, Inc.

Dr. Avera presents his independent assessment of the fair and reasonable rate of return on equity for Black Hills Power and Black Hills Power's requested capital structure.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Direct Testimony and Exhibits
Kyle D. White

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Kyle D. White, 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota.

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

A. I am currently employed by Black Hills Service Company ("Service Company"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), as Vice President of Regulatory Affairs. My areas of responsibility include regulatory affairs for the regulated electric utility subsidiaries of BHC.

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

A. I am testifying on behalf of Black Hills Power, Inc. ("Black Hills Power" or "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I graduated with honors from the University of South Dakota in May of 1982 with a Bachelor of Science degree in Business Administration, majoring in management. In August of 1989, I graduated with a Masters degree in Business Administration, also from the University of South Dakota. I have been employed by BHC in rate, marketing and resource planning related work since July of 1982 and have been in my present position since August of 2012. For much of my career, I was responsible for the preparation of rate studies and other filings for Black Hills Power. In addition to on-the-job training, I have attended numerous seminars, trade association meetings, and regulatory conferences covering a variety of utility-related subjects.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an overview of BHC's subsidiary structure. I also discuss the class cost of service and the proposed rates. In addition, I discuss the Statement R coal pricing and present the business case for utility-owned generation. Lastly, I support the decision to construct Cheyenne Prairie Generating Station ("CPGS").

III. BLACK HILLS CORPORATION OVERVIEW

Q. PLEASE GIVE A BASIC OVERVIEW OF BHC AND ITS SUBSIDIARIES.

A. BHC is a diversified energy company that is headquartered in Rapid City, South Dakota with a 130 year history. BHC operates as a "holding company" under the Public Utility Holding Company Act of 2005. It operates in the United States with two major business groups: 1) Utilities – which deliver retail electric and natural gas service, and 2) Non-regulated Energy – which is involved in various wholesale energy businesses.

Q. WHAT IS THE RELATIONSHIP BETWEEN BHC AND BLACK HILLS POWER?

A. Black Hills Power is a wholly-owned subsidiary of BHC. Black Hills Power is a component of BHC's Utilities Business Segment. Attached as Exhibit KDW-1, is the organization chart for BHC and its subsidiaries. Also, attached as Exhibit KDW-2, is the listing of subsidiaries and the classification of those subsidiaries into the two major business groups – Utilities and Non-regulated Energy.

Q. WHAT OTHER UTILITIES ARE OWNED BY BHC?

A. As shown on Exhibit KDW-2, Black Hills Power's sister electric utilities include Cheyenne Light, Fuel and Power Company ("Cheyenne Light"), which operates in the City of Cheyenne, Wyoming and portions of Laramie County; and Black Hills/Colorado Electric Utility Company, which operates in the Pueblo area of Colorado. In addition, BHC owns gas distribution utilities operating in Colorado, Nebraska, Iowa, Kansas, and Wyoming. These utilities conduct business under the assumed names of Black Hills Energy and Cheyenne Light.

Q. WHAT ARE THE COMPANIES INCLUDED IN THE NON-REGULATED ENERGY GROUP OF BHC?

A. BHC's Non-regulated Energy businesses include: Wyodak Resources Development Corporation ("Wyodak Resources"), which is engaged in coal production and sales; Black Hills Exploration and Production, Inc., which is engaged in oil and natural gas production; and Black Hills Electric Generation, LLC and its subsidiaries, which are engaged in independent power production.

IV. CLASS COST OF SERVICE

Q. HAVE YOU REVIEWED THE RESULTS OF THE CLASS COST OF SERVICE PREPARED BY MR. GRAY?

A. Yes, I have.

Q. WHAT DID YOU DETERMINE?

A. Material differences now exist in the revenue increases required for each class to pay its allocated cost of service. These increases are larger for some classes than is warranted at this time. This result is different than occurred in Black Hills Power's last application for an increase in base rates which the Commission considered in 2013. The Class Cost of Service Model ("CCOS") is provided as Statement O of Exhibit 4.

Q. DO YOU HAVE AN OPINION AS TO WHY THIS HAS OCCURRED?

A. Yes, this is the first class cost of service study since load research data became available from the Company's Advanced Metering Infrastructure (AMI) and the recently installed Meter Data Management System (MDMS). Prior to this study, the Company either borrowed load research data from other utilities and made adjustments to it for perceived differences or utilized old information under the presumption that load characteristics by class had not materially changed. As a result of the availability of nearly census hourly load data for all of Black Hills Power's retail customers, we now have precise data we can use for determining class capacity allocators. However, this data is for one summer peak season only. Additional years of load measurements would help increase the Company's confidence that the reported load data represents a "typical" or "normal" consumption of customers within each class.

Q. WHAT IS BLACK HILLS POWER'S RATE DESIGN PHILOSOPHY?

A. Black Hills Power's primary principle for rate design is the creation of fair and consistent rates. The rate design is intended to balance the revenue responsibilities of Black Hills Power's customers with the right of the Company to recover the reasonable costs incurred to provide service to its customers.

Black Hills Power recognizes that the process of adopting and applying a specific rate design requires judgment, and is a complex and somewhat iterative process. The Company understands that preparing and proposing a rate design that is consistent with this philosophy involves various overlapping and sometime conflicting considerations.

Q. WHAT ARE THOSE CONSIDERATIONS?

A. The rate design considerations include, but are not limited to, the following:

(1) collection of Black Hills Power's total annual revenue requirement and the allocation of those revenues to each customer class to recover costs from those customers that cause those costs to be incurred;

(2) recognition of the cost to serve, as reflected by a class cost of service study that attributes costs to the different classes of customers based on how those customers cause costs to be incurred;

(3) encouragement of the optimum use of supply sources by promoting desirable and discouraging undesirable load characteristics;

(4) recognition of the value of service considering the nature and level of competition and the degree of price sensitivity in each rate class;

(5) avoidance of undue discrimination between customer classes and individual customers within each class;

(6) history of rates, including trends in the level of charges and stability of the rates;

(7) rate structures and terms and conditions of service which are easy to administer and be understood by customers;

(8) consideration of the rates and practices of other utilities having similar types of load and service conditions; and

(9) redesign of rates and services to reflect industry movement when appropriate.

V. PROPOSED RATES

Q. HOW HAS THE ADDITION OF AMI DATA CHANGED THE ALLOCATION OF COSTS TO THE VARIOUS CUSTOMER CLASSES?

A. Black Hills Power can now utilize more complete customer and system data through its AMI meters and MDMS information systems that was not previously available. Now that Black Hills Power can obtain and analyze this specific customer class data, it can better identify methodologies and class demands to fairly allocate the costs of providing service. In addition, Black Hills Power can determine how the costs to be allocated will impact the different customer classes.

Upon reviewing the more complete data in this case, Black Hills Power determined that a reallocation of certain costs from one customer class to another is necessary. However, because the Company has information from the AMI and MDMS data collection, Black Hills Power recognizes that it must apply gradualism in the reassignment of costs. Accordingly, the proposed allocation of costs moves toward a full cost of service approach yet recognizes that the shift of costs must be done in a transitional manner to avoid significant and sudden impacts to customers.

Q. IS THE COMPANY PROPOSING THAT RATES BE APPROVED FOR EACH CUSTOMER CLASS TO RECOVER ITS ALLOCATED COST OF SERVICE?

A. No. While the cost-based rates would allocate the revenue requirement needed to each customer class to recover each class' current cost causation, the Company does not propose to move rates to fully cost-based rates. Doing so would produce greater customer impacts to certain classes than the Company believes is appropriate and acceptable.

Q. HOW DID THE COMPANY DETERMINE THE PROPOSED CLASS REVENUE RESPONSIBILITY?

A. The primary guide for the proposed class revenue responsibility is the class cost of service study. Moderation, gradualism, and rate stability were also considered by comparing class costs as a percentage increase from the present rate levels, relative to the proposed overall 9.27 percent increase to revenues. While the total overall revenue increase is 9.27 percent, the results of the class cost of service study shows various rate changes should rates be set to match the study results for each individual customer class.

Q. WHY DID BLACK HILLS POWER CHOOSE GRADUALISM?

A. With the variance in the allocated class percentages as compared to the overall percentage increase, Black Hills Power chose to exercise caution and developed rates that begin the move toward cost based rates while acknowledging the history of the relationship of the rates, including trends in the level of charges and stability and predictability of rates. The Company seeks to avoid undue discrimination between customer classes and similarly situated individual customers within each class. Black Hills Power must also be cognizant of customer reactions to a move to fully cost-based rates.

By employing the practice of gradualism when changing rates, significant rate shifts can be minimized by moving a rate class to its full cost of service rates through smaller step changes over time, as opposed to one large jump to full cost of service. The proposed rates allow the Company to move all classes toward cost based rates in moderation. This moderation is expected to require future reallocations of required revenues to each customer class to appropriately recover utility costs from those customer classes that are shown to cause those costs to be incurred by Black Hills Power.

Q. PLEASE EXPLAIN HOW THE CLASS REVENUE RESPONSIBILITIES WERE DEVELOPED.

A. Due to the newness of the shown inequities between the expected returns between the five customer classes under current rates, the Company proposes to increase the charges for all classes consistent with certain constraints. Under the proposed rate design, no customer class will receive an increase which is less than 75 percent of the overall revenue increase. Also, no customer class will experience an increase greater than 120 percent of the overall increase for all customers. The boundaries for acceptable percentage increases then become approximately 7 percent and 12 percent. This proposed class revenue allocation provides an appropriate and reasoned movement of rates to class cost levels to maintain accurate and equitable pricing while being tempered by moderation. The moderation in this proposal also recognizes the overall level of the proposed increase.

Using the proposed class revenues and applying rate design factors mentioned above, Black Hills Power developed appropriate base rate charges. These charges are necessary to allow Black Hills Power the opportunity to recover, from each class, the currently appropriate class revenue requirement and the total annual revenue requirement as applied for by the Company.

Q. ARE THERE OTHER REASONS WHY NOW IS NOT THE APPROPRIATE TIME TO MOVE TO FULLY COST-BASED RATES?

A. Yes. With the electric utility industry on the verge of fully deploying AMI, there will likely be innovations in how customer groupings are determined, along with an increased utilization of rate designs applicable to load data rich metering. Rates which may see increased application include demand rates, time of use rates and peak control rates. Rather than subjecting customers to the impact of full cost of service rates today and then coming forward in a few years with another major change, Black Hills Power would prefer to wait to see what develops.

Q. DO YOU BELIEVE THAT THE RATES AND CHARGES PROPOSED BY THE COMPANY WILL RESULT IN JUST AND REASONABLE RATES?

A. Yes. With my years of experience in rate making and my understanding of the situation presented today, I believe that the Company's proposal is fair and will result in just and reasonable rates.

VI. <u>PROPOSED CHANGES TO TARIFFS</u>

Q. HAS THE COMPANY MADE CHANGES TO THE APPLICABILITY PROVISIONS OF ITS RESIDENTIAL TARIFFS IN RESPONSE TO INCREASING INTEREST NATIONALLY IN CUSTOMER-OWNED BEHIND THE METER DISTRIBUTED GENERATION?

A. Yes.

Q. PLEASE PROVIDE THE REASONS FOR THIS CHANGE IN APPROACH?

A. Nationally, customers are showing a growing interest in utilizing distributed self-generation for meeting portions of the electricity they require within their homes. Due to traditional approaches for pricing residential electric service, these customers are often receiving more savings incentive for their self-generation than is appropriate for the costs the utility saves by not fully serving them. Additionally, because residential charges frequently have not been set to match costs, the utility also fails to recover the real cost to serve the partially self-generating residential customers. These unbilled costs then must be paid by all other residential customers. Black Hills Power is fortunate that for over three decades it has offered the Residential Demand Service rate which has the appropriate pricing that can be used for this type of application.

Q. WHAT CHANGES HAVE BEEN MADE TO THE RESIDENTIAL TARIFFS?

A. Language has been added to the APPLICABLE section of the Residential Demand Service tariff to specify that residential partial requirements service will only be available under this rate schedule. The Residential Service tariff and the Total-Electric Residential Service will be available for all-requirements service only. Black Hills Power has some residential customers that have generation interconnection agreements related to their service requirements. For these customers the Residential Demand Service schedule includes language whereby they can remain on the rate schedule applicable at the time when their agreement became effective for the term of the agreement or through September 30, 2024, which ever period is shorter. By making the changes at this time, this grandfathering provision would only apply to about a dozen customers. The result is that Black Hills Power's customers will have appropriate price signals should they consider investing in distributed generation for meeting some of the electricity requirements for their homes.

VII. STATEMENT R COAL PRICING

Q. PLEASE EXPLAIN THE COAL SUPPLY ARRANGEMENT FOR BLACK HILLS POWER'S COAL FIRED POWER PLANTS.

A. Black Hills Power has a Coal Supply Agreement with Wyodak Resources to provide coal to the Company's coal-fired power plants. The pricing for the Coal Supply Agreement is based on what the Company refers to as 'Statement R' pricing because it has historically corresponded to the Statement in the rate case application that details the coal price calculation for coal purchased from the Company's affiliate. Under this methodology, Black Hills Power's coal costs are determined by calculating the amount that allows Wyodak Resources to recover its cost of service related to the coal sales to Black Hills Power, plus a return on investment. That return is the average interest rate for new, long-term A-rated utility bonds issued during the calendar year for which the calculation is being made, plus four hundred basis points. This is a utility type rate of return methodology. This methodology has been presented and accepted by this

Commission previously for Black Hills Power for decades. In addition, this pricing methodology has been accepted by third parties with ownership interests at the Gillette Energy Complex such as the City of Gillette and Montana Dakota Utilities Co.

Q. DO BLACK HILLS POWER'S CUSTOMERS BENEFIT FROM THE EXISTENCE OF THE COAL SUPPLY AGREEMENT?

A. Yes. The coal supply arrangement is beneficial to Black Hills Power's customers for several reasons. All remaining coal-fired power plants are mine-mouth facilities, which eliminate almost all transportation costs. In addition, the Coal Supply Agreement is a long term supply agreement, providing coal for the life of the facilities.

VIII. <u>BUSINESS CASE FOR UTILITY OWNED GENERATION</u>

Q. ARE THERE BENEFITS OF UTILITY OWNED GENERATION?

A. Yes. In the three decades that I have worked in the utility industry, I have seen the results of both long-term power purchase relationships and utility-owned generation. I have come to strongly believe that the best resource acquisition for meeting the majority of customer electricity requirements is to own and control generation. There are several benefits to utility ownership including the following:

- Typically utility owned generation provides more price stability for customers over the long term than power purchase agreements ("PPA") that have shorter terms than the expected useful life of the generation. By owning and controlling generation, Black Hills Power can protect customers from market forces that may drive prices up when the utility is seeking new supply to replace a PPA that is expiring. Frequently PPA suppliers seek renewal prices that are higher than what the underlying generation assets would allow under cost-based regulation. It can be said that under twenty year PPAs, the customers often pay for the supplier's generation facilities more than once. Also, constructing and owning generation gives Black Hills Power customers the security of supply and the cost benefits of long-lived and depreciating assets. With utility-owned generation, the rate base declines over time while PPAs typically have lower cost at the beginning, but rise over the term of the agreement.

- The utility has an obligation to provide customers with reliable service; therefore, it has no motivation to let demand outpace supply, which increases the cost of generation and ultimately the cost to customers. In other words, utilities are paid for their actual cost of providing the generation while independent power producers generally are providing power at the market price which may be affected by the laws of supply and demand.
- The utility's profits on generation come in the authorized return on equity on the actual capital invested in the generating resource. This return is typically less than that required by a competitive non-regulated entity. Since independent power producers may charge market-based rates under a

tariff on file with the Federal Energy Regulatory Commission ("FERC"), the only limit on the size of that return is the market value for purchased power.

- Utility ownership of capacity provides operational benefits and security and will result in a more financially sound utility, which benefits customers. These benefits include outage management, dispatch, ramp rates, unit commitments and capital additions for increased efficiency and life extension, and also compliance with new regulations. Often PPAs limit the flexibility the utility has in utilizing the resource to meet changing operating conditions.

IX. SUPPORT FOR THE DECISION TO CONSTRUCT CPGS

Q. PLEASE PROVIDE A SUMMARY OF THE DECISION TO CONSTRUCT CPGS.

A. In 2011, Cheyenne Light recognized that it would need new electric resources to offset load growth and the expiration of long-term PPAs. As a consequence, Cheyenne Light completed an integrated resource plan ("IRP") that identified a capacity deficit of 93 MW in 2014 and exceeding 150 MW by the end of the 20-year plan. Consistent with the IRP, Cheyenne Light filed an Application for a Certificate of Public Convenience and Necessity on August 1, 2011 with the Wyoming Public Service Commission to construct three combustion turbine generators ("CTG") on a site in Cheyenne, Wyoming.

At the same time, Black Hills Power began work on an IRP to identify the future needs of its customers. The future resource needs of Black Hills Power were driven primarily by the impact of environmental regulatory requirements on its existing generating facilities. Based on regulatory requirements and economics, the Black Hills Power IRP identified that the Ben French, Neil Simpson I, and Osage coal-fired units owned by Black Hills Power will be retired in 2014. In addition, certain PPAs of Black Hills Power will terminate over the 20-year IRP planning horizon.

The preferred plan identified in the Black Hills Power IRP included the conversion of a CTG to combined cycle ("CC") 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 CC resource in Cheyenne would present an opportunity for both Black Hills Power and Cheyenne Light.

To assess the benefits and risks of a jointly-owned CC unit, Black Hills Power and Cheyenne Light undertook additional analysis and modeling to determine the financial impact on the completed resource plans. 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 identified in Cheyenne Light's original IRP.

Q. WHY DOES BLACK HILLS POWER BELIEVE A CC IS THE APPROPRIATE GENERATION RESOURCE FOR ITS CUSTOMERS?

A. Black Hills Power believes that the increased initial capital cost per kW of a CC, as compared to CTGs, will be offset by the benefits associated with a more fuel efficient CC. The advantages of a CC include operation at a lower heat rate, lower environmental emissions, and reduced exposure to future environmental mandates or taxes. In addition, Black Hills Power believes that it is in the best interest of customers to build and own generation rather than relying on PPAs. Therefore, Black Hills Power believes that the construction of the jointly owned CC will provide reliable electricity to its customers for years to come and mitigate the risk of economy energy not being available in the market.

Q. WHY DID BLACK HILLS POWER ELECT TO CONSTRUCT A NEW GENERATION FACILITY IN CHEYENNE WYOMING?

A. The Cheyenne, Wyoming location was chosen for CPGS because it provides an adequate and efficient water supply, an abundant natural gas supply, and access to available electric transmission.

Q. HAS THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION ("COMMISSION") HAD AN OPPORTUNITY TO CONSIDER ANY FILINGS RELATED TO CPGS?

A. Yes. Pursuant to S.D.C.L. §§ 49-34A-73 to 78, Black Hills Power filed an Application for the Phase In of Rates Regarding CPGS Construction Financing Costs with the Commission on December 17, 2012, Docket EL12-062. On

September 19, 2013, the Commission approved the phase in plan rate for CPGS through a Decision and Order Granting Joint Motions for Approval of Settlement Agreement and Settlement Stipulation.

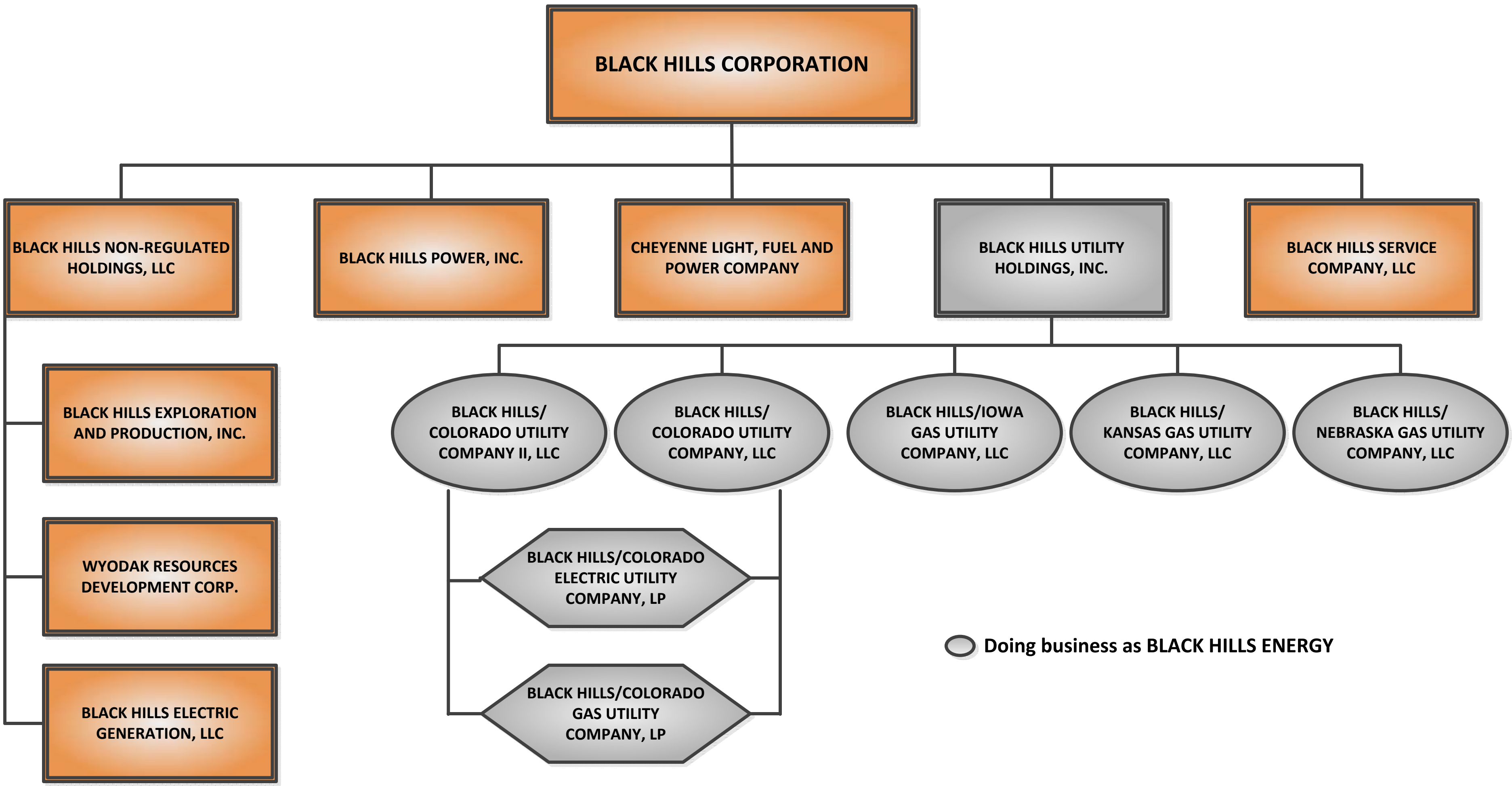
Q. DID BLACK HILLS POWER OBTAIN A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR CPGS FROM THE WYOMING PUBLIC SERVICE COMMISSION?

A. Yes. Black Hills Power and Cheyenne Light filed a Joint Application for a Certificate of Public Convenience and Necessity ("CPCN") on November 1, 2011, which was approved by the Wyoming Public Service Commission by a Memorandum Decision dated January 8, 2013, in Docket Nos. 20002-81-EA-11 and 20003-113-EA-11 (Record No. 13007).

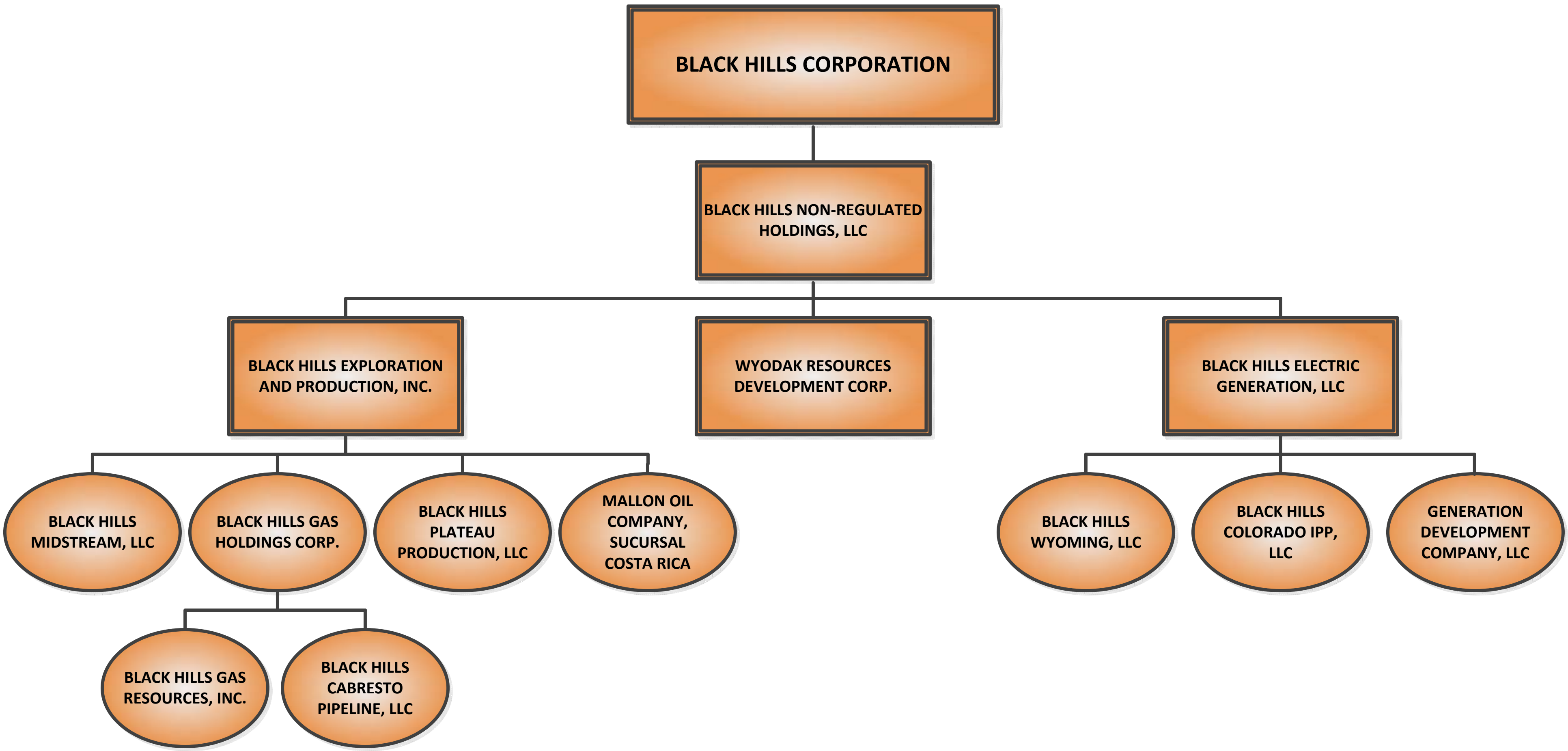
Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BLACK HILLS CORPORATION ORGANIZATIONAL CHART



BLACK HILLS CORPORATION ORGANIZATIONAL CHART



Black Hills Corporation Subsidiaries

Our subsidiaries are classified with two major business groups – Non-regulated Energy and Utilities

Non-regulated Energy

Black Hills Non-regulated Holdings, LLC ("Black Hill Non-regulated Holdings")

Black Hills Electric Generation, LLC ("Black Hills Electric Generation")

Black Hills Exploration and Production, Inc. ("Black Hills Exploration & Production")

Wyodak Resources Development Corp. ("Wyodak")

Utilities

Black Hills Power, Inc. ("Black Hills Power")

Black Hills Utility Holdings, Inc. ("Black Hills Utility Holdings")

Black Hills/Colorado Electric Utility Company, LP ("Colorado Electric") d/b/a Black Hills Energy

Black Hills/Colorado Gas Utility Company, LP ("Colorado Gas") d/b/a Black Hills Energy

Black Hill/Iowa Gas Utility Company, LLC ("Iowa Gas") d/b/a Black Hills Energy

Black Hills/Kansas Gas Utility Company, LLC ("Kansas Gas") d/b/a Black Hills Energy

Black Hills/Nebraska Gas Utility Company, LLC ("Nebraska Gas") d/b/a Black Hills Energy

Cheyenne Light Fuel and Power Company ("Cheyenne Light, Fuel & Power" or "Cheyenne Light")

Direct Testimony and Exhibits
Jill S. Tietjen

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. EL14-___

March 31, 2014

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EXHIBITS

I. INTRODUCTION & QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jill S. Tietjen. My business address is 8547 E. Arapahoe Road, PMB J189, Greenwood Village, Colorado.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am the President and CEO of Technically Speaking, Inc., a firm that provides engineering consulting services. I have held this position since the firm was incorporated in August of 2005. Previously, I was self-employed as an engineering consultant.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND WORK BACKGROUND.

A. I graduated from the University of Virginia with a B.S. in Applied Mathematics (minor in Electrical Engineering) in 1976. I began my career with Duke Power Company and spent five years as a Planning Engineer in the System Planning Department (1976-1981). While at Duke Power Company, I earned my MBA from the University of North Carolina at Charlotte in 1979. I subsequently joined Mobil Oil Corporation's Mining and Coal Division where I worked from 1981-1984 as a planning analyst. I became a registered professional engineer in Colorado in 1982. I joined Stone & Webster Management Consultants in 1984 and by the time I left in 1992 had progressed to Assistant Vice President. I served as Principal and leader of the utility planning practice at Hagler Bailly Consulting during 1992-1995. In 1995, I rejoined Stone & Webster Management Consultants as an Assistant Vice President and office manager for the Denver office, a position that I served in through 1997. Since 1997, I have been on staff at the University of Colorado at Boulder. From 1997-2005, I was also self-employed as an engineering consultant. Also in 1997, I was elected as an outside director on the Board of Directors of Georgia Transmission Corporation and still serve in that capacity. In 2010, I was elected as an outside director for Merrick & Company of Aurora, Colorado. My resume, testimony listing, and publications listing are attached to my testimony as Exhibit JST-1.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes. I have testified before regulatory commissions in South Dakota, Wyoming, Colorado, Illinois, Kansas, Kentucky, Maine, Missouri, and Ohio. I have testified on behalf of Black Hills Corporation subsidiaries in South Dakota, Wyoming and Colorado.

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

A. I am testifying on behalf of Black Hills Power, Inc. (Black Hills Power).

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I demonstrate the need for a new resource on the Black Hills Power system in the 2014 timeframe. I discuss Black Hills Power's 2011 Integrated Resource Plan (BHP IRP) that was conducted to determine how that resource need should be fulfilled. I then discuss the selection of the Cheyenne Prairie Generating Station

(CPGS) as the resource that should be installed in 2014 and the associated rationale.

III. NEED FOR RESOURCES

Q. PLEASE DESCRIBE THE FACTORS AFFECTING THE NEED FOR NEW RESOURCES ON THE BLACK HILLS POWER SYSTEM.

A. Two primary factors are driving the need for new resources on the Black Hills Power system. The first is regulations promulgated by the Environmental Protection Agency (EPA) and the resulting retirements of several of Black Hills Power's older coal-fired generating units. The second is the expiration of the Reserve Capacity and Integration Agreement (RCIA) between Black Hills Power and PacifiCorp.

Q. HOW DID BLACK HILLS POWER EVALUATE THE COST OF RETROFITTING THE POWER PLANTS THAT DO NOT COMPLY WITH THE NEW EPA NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR AREA SOURCES: INDUSTRIAL, COMMERCIAL AND INSTITUTIONAL BOILERS (AREA SOURCE RULES)?

A. Black Hills Power contracted with an engineering firm, CH2M HILL, to perform an analysis on several of its smaller coal-fired generating units. The analysis provided an estimate of the capital cost to add emission controls to these units to meet the existing and future air pollution control requirements. These requirements would entail the addition of emission controls, installation of monitoring equipment, restrictions on the quality of coal received and adherence to new operating parameters established during the compliance test. The units evaluated were Neil Simpson Unit 1; Osage Units 1, 2, and 3; and Ben French Unit 1, which are all coal-fired units. After reviewing the study results, including life extension costs, Black Hills Corporation made the decision to retire (and replace) the Neil Simpson 1, Osage 1-3 and Ben French 1 units because that option was more cost effective than retrofitting the units. Ben French, Osage 1-3, and Neil Simpson 1 were officially retired in March of 2014. With these retirements, Black Hills Power's generation capacity was reduced by 71 MW.

Q. WHEN DID THE RCIA EXPIRE AND WHAT IS THE RESULT OF THAT EXPIRATION?

A. The RCIA expired June 30, 2012. Under the RCIA, Black Hills Power could count the Ben French combustion turbine (CT) capacity as 100 MW. This was important because the output from Black Hills Power's older coal-fired generating units is reduced at higher ambient temperatures. Those higher temperatures occur in the summer months of June, July, and August, and coincide with Black Hills Power's peak load periods. The RCIA allowed Black Hills Power the right to call on PacifiCorp for any of the 100 MW that could not be generated by the Ben French CTs. After termination of the RCIA, the Ben French CTs are rated at 72 MW in the summer. This means that the termination of the RCIA has led to a total of 28 MW of capacity that could no longer be counted as Black Hills Power resources available to meet the summer peak demand. This loss of 28 MW of capacity began July 1, 2012.

Q. IN TOTAL, HOW MUCH NET SUMMER CAPACITY WILL BLACK HILLS POWER HAVE RETIRED OR OTHERWISE LOST BETWEEN 2011 AND 2014?

A. Black Hills Power will have lost 99 MW of net summer capacity, calculated as follows:

RCIA expiration	28 MW
Osage retirement	33 MW
Ben French retirement	22 MW
Neil Simpson 1 retirement	16 MW
TOTAL	99 MW

Q. PLEASE DESCRIBE HOW TO FIND THIS 99 MW DECREASE IN RESOURCES IN THE BHP IRP.

A. The Load and Resource Balance provided as Appendix B in the BHP IRP reflects the 28 MW loss due to the expiration of the RCIA and the retirements of Ben French 1 (22 MW) and Neil Simpson 1 (16 MW). A discussion of the retirement of the Osage units (33 MW) is contained in Section 6.2 of the BHP IRP. Because the Osage units were in cold storage at the time the BHP IRP was conducted (and not expected to be reactivated before their 2014 retirement), those 33 MW of capacity are not reflected as available either in Table 6-1 or Appendix B of the BHP IRP.

Q. WHAT PERCENTAGE OF BLACK HILLS POWER'S PEAK DEMAND IS REPRESENTED BY THIS 99 MW OF CAPACITY LOSSES FROM 2012 THROUGH 2014?

A. In the BHP IRP, Black Hills Power's peak demand in 2014 is estimated to be 430 MW (see Table 4-1 of the BHP IRP). Thus, the loss of 99 MW represented 23% of Black Hills Power's 2014 projected peak summer demand.

IV. BLACK HILLS POWER'S INTEGRATED RESOURCE PLAN

Q. PLEASE DESCRIBE THE BHP IRP.

A. The BHP IRP examined the period 2011-2030 and determined the appropriate resources to fill resource needs over that 20-year period. A load forecast of projected peak demands and annual energy consumption was developed. Appropriate assumptions were made for the wide variety of parameters required to model the operation of the generating units. Characteristics required to model all existing resources were confirmed. The analysis considered a range of conventional supply-side resources as well as renewable resources with modeling and operational parameters developed for each. The computer modeling that was conducted consisted of capacity expansion, production costing, sensitivity, and risk analysis. Ventyx, a leading integrated resource planning vendor, performed the computer modeling. The BHP IRP is provided as Exhibit JST-2 to my testimony.

Q. WHAT CATEGORIES OF ASSUMPTIONS UNDERLIE THE PREPARATION OF AN IRP?

A. In addition to the load forecast, assumptions are needed for fuel prices, financial parameters, capital cost of generation resources, the level of reserves required, plant operational parameters, and the market price of energy. Assumptions must also be made for the demand-side management programs put in place during the planning period and their peak demand and annual energy impact.

Q. PLEASE DESCRIBE THE PRICE FORECASTS USED FOR FUEL COSTS IN THE BHP IRP.

A. Black Hills Power used a coal price forecast that reflects the cost as of May 2011 incurred for fuel delivered to its coal-fired power plants. The coal prices were then escalated to result in the forecast to match the Ventyx reference case, with annual coal escalation averaging about 3% per year. Natural gas price forecasts were developed from Ventyx's WECC 2011 Spring Reference Case Henry Hub forecast. The Henry Hub values were adjusted for transportation costs to more accurately reflect the price of natural gas as delivered to Black Hills Power's generating facilities.

Q. PLEASE DESCRIBE THE ASSUMPTIONS USED FOR THE MARKET PRICE OF ENERGY.

A. Electricity price estimates for the Wyoming region were derived from Ventyx's 2011 Spring Reference Case and are the basis on which Black Hills Power's market transactions were priced. Values were developed for four differing scenarios that require correlation between natural gas prices and market prices – base, environmental, low gas, and high gas.

Q. PLEASE DESCRIBE THE FINANCIAL PARAMETER ASSUMPTIONS USED FOR THIS IRP.

A. Assumptions were required for various financial parameters, including the discount rate, the capital structure, and the levelized fixed charge rates for each of the resource alternatives. The assumptions used for the BHP IRP are shown on Table 3-3.

Q. PLEASE DESCRIBE THE CAPITAL COSTS OF GENERATION RESOURCE ASSUMPTIONS.

A. Black Hills Power used the Ventyx 2011 Spring Reference Case assumptions for capital costs of a variety of generation resources (shown in Tables 6-3 through 6-8). These assumptions include the direct capital costs of coal, a variety of natural gas-fired configurations and renewable generation that are non-site specific. This means that the costs for transmission interconnection, gas fuel supply system installation and ancillary equipment were not included in the capital cost assumptions.

Q. WHAT LEVEL OF PLANNING RESERVE MARGIN WAS USED FOR THE BHP IRP AND HOW WAS THIS LEVEL DETERMINED?

A. Black Hills Power assumed a planning reserve margin of 15% over projected peak demand for this analysis. It was anticipated that the level of reserve margin required by Black Hills Power will not change during the entire 20-year planning horizon evaluated in the BHP IRP.

Q. PLEASE DESCRIBE THE DEMAND-SIDE MANAGEMENT ASSUMPTIONS USED FOR THE BHP IRP.

A. The Black Hills Power Demand-Side Management programs as defined in SD PUC Docket #EL11-002 and approved by the Commission were assumed to be implemented. Those programs and the associated savings in demand and energy are reflected in Section 5.0 of the BHP IRP.

Q. PLEASE DESCRIBE THE RANGE OF NEW CONVENTIONAL RESOURCES EXAMINED IN THE COURSE OF PREPARING THE BHP IRP.

A. Conventional resources examined in the BHP IRP include coal-fired capacity, natural gas-fired simple cycle and combined cycle combustion turbines, the purchase of a portion of an existing unit, and firm market purchases.

Q. PLEASE DESCRIBE THE RENEWABLE RESOURCES EXAMINED IN THE COURSE OF PREPARING THE BHP IRP.

A. The renewable resources examined were wind and solar photovoltaics.

Q. PLEASE DESCRIBE THE PROCESS USED TO DETERMINE THE LOAD FORECAST AND THE RESULTS.

A. Ventyx developed a load forecast for Black Hills Power by trending historical peak demands and annual energy and modifying the results for expected load additions in 2012 through 2016. The trended growth for Black Hills Power is

1.0% for both peak demand and annual energy as shown on Table 4-1 of the BHP IRP. These growth rates do not reflect any significant increases in loads for major industrial customers on the Black Hills Power system as no significant increases were expected at the time the BHP IRP was prepared. As set forth in the BHP IRP, loads for major industrial customers are expected to trend forward without significant decreases or increases throughout the planning horizon.

Q. HOW DOES THE LOAD FORECAST DETERMINE CAPACITY REQUIREMENTS FOR BLACK HILLS POWER?

A. Black Hills Power must maintain sufficient capacity to support peak load requirements plus planning reserves. Black Hills Power has a legal obligation to serve the needs of its customers – as those needs exist today and as they grow over time. The first year that Black Hills Power has a capacity deficit is 2014 as shown on Figure ES-1.

Q. PLEASE BRIEFLY EXPLAIN CAPACITY EXPANSION MODELING.

A. Capacity expansion modeling is a process used to determine the appropriate type, size, and timing for economic resource additions for utilities. The utility's existing generation resources and future resource alternatives are inputted into a capacity expansion model with a forecasted load and other appropriate parameters over the entire planning horizon. The model simulates utility operation, serves the forecasted load with the utility's existing resources, and economically "selects" additional resources from the list of available resource alternatives subject to the planning constraints. The typical criterion for evaluation is the expected present value of revenue requirements (PVRR). Capacity expansion plans are developed for scenarios that vary the assumptions in order to simulate changing market and load conditions.

Q. PLEASE BRIEFLY EXPLAIN PRODUCTION COSTING MODELING.

A. Production cost modeling is a process used to forecast system costs over a specified planning horizon. A production cost model includes an hourly dispatch model, with a load forecast and fixed resources to serve that load. The model simulates a load every hour, then economically serves that load with the available resources, and captures the associated cost.

Q. WHAT SCENARIOS WERE EXAMINED IN THE BHP IRP?

A. As described in Section 7.1 of the BHP IRP, scenarios examined included base, environmental, high gas, low gas, high load, low load, step load, Gillette Top Load, Base with No Firm Market, and No Combined Cycle Conversion Option. What this means is that alternative expansion plans were developed for each scenario, costs were determined for each scenario, and a risk assessment was conducted for each scenario. The resulting optimal expansion plans for each scenario are reflected on Table 7-2 of the BHP IRP. A conversion of a combustion turbine to combined cycle operation was selected as the resource choice for 2014 for each scenario except the scenario in which that resource option was specifically excluded (which is reflected in the BHP IRP as the "No CC Conv Option").

Q. HOW DOES THE 2011 LOAD FORECAST COMPARE TO ACTUALLY EXPERIENCED LOADS IN THE 2011-2013 TIME FRAME?

A. The 2011 peak demand of 452 MW and the 2012 peak demand of 449 MW reached levels that were forecast for the 2017-2018 time frame in the BHP IRP. The 2013 peak demand experienced was lower than forecast in the BHP IRP.

Q. IN WHAT YEAR DID THE BHP IRP FIRST SHOW A CAPACITY DEFICIT?

A. The first year to show a capacity deficit in the BHP IRP is 2014. This capacity deficit is shown graphically in Figure ES-1 on page ES-5 of the BHP IRP.

Q. WHAT GENERATION RESOURCE WAS SELECTED IN THE BHP IRP TO MEET THE 2014 RESOURCE NEED.

A. The resource shown to meet Black Hills Power's 2014 need in the BHP IRP is the conversion of a combustion turbine unit to combined cycle operation. This resource selection results in the addition of 55 MW to the Black Hills Power system. Thus, in order to satisfy reserve margin requirements, the BHP IRP further shows that Black Hills Power would purchase 25 MW of firm power in 2014. Note that as discussed previously in my testimony, 99 MW of resources are no longer available due to retirements and contract expiration. The BHP IRP selects 80 MW of resources in 2014 (less than 99 MW) to meet reserve margin criteria and serve load.

V. <u>SELECTION OF CPGS</u>

Q. DO YOU BELIEVE THAT THE BHP IRP SELECTED A RESOURCE LIKE OR SIMILAR TO CPGS?

A. Yes. The BHP IRP selected a 2014 resource that was the conversion of a simple cycle combustion turbine to combined cycle operation, resulting in the addition of 55 MW to the Black Hills Power system, plus the procurement of 25 MW of firm market power. As stated in the Executive Summary and the Action Plan of the BHP IRP, Black Hills Power's 2014 resource would be procured by "Purchase or otherwise obtain a simple cycle combustion turbine to be converted to combined cycle operation in 2014." The BHP IRP does not specify location or size of that simple cycle combustion turbine other than that it supports a 55 MW addition when converted to combined cycle operation.

Q. DO YOU THINK THAT A SIMPLE CYCLE COMBUSTION TURBINE CONVERTED TO COMBINED CYCLE OPERATION IN CHEYENNE, WYOMING IS WHAT WAS INTENDED BY THE BHP IRP?

A. Yes. I think it is one of several choices available to Black Hills Power. I believe that an IRP identifies the type of resource that makes the most economic sense to add for any given capacity deficit. I further believe that it is up to the utility to make the business decision based on the business case that makes the most sense for that utility's customers. In this instance, an opportunity existed for synergies with a capacity need demonstrated by an affiliate of Black Hills Power –

Cheyenne Light, Fuel & Power. In my opinion, Black Hills Power properly took advantage of those synergies to construct CPGS.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

JILL S. TIETJEN

An electrical engineer experienced in electric utility and related planning processes and analyses, primarily in the areas of generation, transmission, and fuels. Experienced expert witness.

EMPLOYMENT CHRONOLOGY

1997-present	Technically Speaking, Inc. (and predecessor organizations), President and CEO
2001-present	University of Colorado at Boulder, Various Titles
2003-2005	Senior Management Consultant, R.W. Beck
2001-2008	Senior Engineer, McNeil Technologies
1997-2000	University of Colorado at Boulder Director, Women in Engineering Program and Independent Consultant
1995-1997	Stone & Webster Management Consultants, Inc. Assistant Vice President
1992-1995	Principal, Hagler Bailly Consulting (Previously RCG/Hagler Bailly)
1984-1992	Stone & Webster Management Consultants, Inc. Assistant Vice President
1981-1984	Mobil Oil Corporation, Planning Analyst, Mining and Coal Division
1976-1981	Duke Power Company, Planning Engineer

CONSULTING ASSIGNMENTS

Examined the process used by Big Rivers Electric Corporation to determine that a scrubber should be installed at Henderson Station Two. Expert witness before the Kentucky Public Service Commission.

Managed several projects relating to the efficiency of qualified facilities. One project involved preparation of an affidavit in a Federal Energy Regulatory Commission hearing. Managed an appraisal of an IPP in bankruptcy.

Evaluated fuel contracts - primarily coal and petroleum coke - associated with cogeneration projects in various states. Evaluated steam and power sales contracts as well as operational aspects, avoided cost projections, and transmission issues of projects. Prepared feasibility studies and financial viability analysis.

Managed competitive bidding solicitations for supply-side and/or renewable resources. Projects included RFP and PPA development and evaluations of bids. Clients: Northern States Power; The Empire District Electric Company; San Diego Gas & Electric; SaskPower; Southwestern Public Service; and Cheyenne Light, Fuel & Power. Independent Evaluator for Southern California Edison and Pacific Gas & Electric RFOs.

Investigated the competitive market price for the sale of power from coal-fired, geothermal, and hydroelectric power plants. Performed earnings value evaluations for appraisal evaluations.

Prepared testimony or affidavits for cases before the Federal Energy Regulatory Commission and before regulatory agencies in the states of Colorado, Illinois, Kansas, Kentucky, Maine, Missouri, Ohio, South Dakota, and Wyoming. Topics have included fuel procurement practices, policies, and procedures; integrated resource planning; nonutility generation markets; economic dispatch practices; avoided costs; fuel and purchased power expenses; and electric system reliability.

Project manager of integrated resource planning studies for Bangor Hydro-Electric, Black Hills Power, and the Empire District Electric Company. Efforts supported with testimony filed in multiple jurisdictions. Authored Integrated Resource Plans for Black Hills Corporation (2005, 2007, 2008) and The Empire District Electric Company (2006, 2007).

Managed fuel practices and policies audits of utilities. Participated in a management audit investigating issues of generation planning. Participated in evaluations of system dispatch practices and procedures.

Served as advisor to the Iowa Utilities Board on a priori ratemaking principles for utility construction of electric power generation in Iowa.

Served as project manager for assessment of alternative wind technologies for a Midwestern utility. Examined the feasibility and economics of biomass generation for a sawmill in Wyoming, an electric utility in Arizona, a reservation in Minnesota, and a public utilities district in California.

Project manager and expert witness for a proceeding in Illinois with regard to a reliability rule proposed by the staff of the Illinois Commerce Commission.

AFFILIATIONS

Society of Women Engineers – 1991-92 National President, Fellow.
Georgia Transmission Corporation, Board of Directors, 1997 – present.
Merrick & Company, Board of Directors, 2010 – present, Vice Chair 2013 – present.
National Women's Hall of Fame, Board of Directors, 2009 – present, President 2014 – present.
Colorado State Board of Registration for Professional Engineers and Professional Land Surveyors, 1996-2004, Chair, 2001-2003.
Institute of Electrical and Electronics Engineers, Power Engineering Society, Senior Member.
International Women's Forum (Colorado), Board of Directors, 1998 – 2000.
Rocky Mountain Electrical League Board of Directors, 1994-2002; President, 1999-2000.
Rocky Mountain Electrical League Foundation Board of Directors, 1999-2006, Chair, 2002-2005.
Girl Scouts – Mile Hi Council Board of Directors, 1999-2007, Chair, 2003-2007.
Board of Trustees, Arapahoe Library District, 1995-2000, President, 1997 – 1999.
Women in Engineering Programs & Advocates Network, Board of Directors, 1995 – 2001.
Leadership Denver 1996.

HONORS

1990 Certificate of Honor, Colorado Engineering Council. 1991 John E. Daly Award for Consulting Excellence, Stone & Webster Management Consultants. Soroptomist International Women of Distinction Award, 1995. Woman of Distinction, Mile Hi Girl Scouts Council, 1997. IEEE *Spectrum* Advisor of the Year, 2000. Presidential Citation Award, Professional Land Surveyors of Colorado, 2000, Woman in Technology Award from the Women's Foundation of Colorado, Subaru, and News4, 2001. Distinguished Service Award, Society of Women Engineers, 2002. Horizon Award, Outstanding Professional, The Partnership to Advance Science, Engineering, and Technology, 2003. Colorado Women's Leadership Coalition, 2004 Woman Leader of Excellence. Virginia Engineering Foundation, 2004, Distinguished Alumni Award. Tau Beta Pi, 2004 Distinguished Alumna Award. One of 50 2004 Trendsetters, *Public Works* Magazine. University of Colorado at Boulder, Distinguished Engineering Alumni Award, 2005. University of Virginia, Distinguished Alumna, 2007. Athena Award Finalist, Colorado Women's Chamber of Commerce, 2009, 2010. Colorado Women's Hall of Fame, 2010.

EDUCATION AND OTHER

University of Virginia, B.S., Applied Mathematics with a minor in Electrical Engineering, 1976. (Tau Beta Pi, Virginia Alpha).
University of North Carolina at Charlotte, M.B.A., 1979.
Registered Professional Engineer, Colorado.

3/2014

JILL S. TIETJEN

Books/Reports/Articles/Speeches

Known as Karen Jill Stein 1954-1976

Known as Jill S. Baylor May 1976-August 1996

Books

1. Quoted in *Members of the Club: The Coming of Age of Executive Women*. 1993. Dawn-Marie Driscoll and Carol R. Goldberg. New York: The Free Press, A Division of Macmillan, Inc.
2. *She Does Math! Real-Life Problems from Women on the Job* (contributing author). 1995. M. Parker, ed. Washington, DC: The Mathematical Association of America.
3. *Keys to Engineering Success*. 2001. Jill S. Tietjen, Kristy A. Schloss, et. al. Upper Saddle River, New Jersey: Prentice Hall. [Brief review in *SWE: Magazine of the Society of Women Engineers*, March/April 2001, p. 4.]
4. *Setting the Record Straight: An Introduction to the History and Evolution of Women's Professional Achievement*. 2001. Betty Reynolds, Ph.D. and Jill S. Tietjen, P.E. Denver, Colorado: White Apple Press.
5. *Setting the Record Straight: The History and Evolution of Women's Professional Achievement in Engineering*. 2001. Betty Reynolds, Ph.D. and Jill S. Tietjen, P.E. Denver, Colorado: White Apple Press.
6. *Setting the Record Straight: The History and Evolution of Women's Professional Achievement in Accounting*. 2005. Betty Reynolds, Ph.D. and Jill S. Tietjen, P.E. Denver, Colorado: White Apple Press.
7. Profiled and Pictured in *Changing Our World: True Stories of Women Engineers*. 2006. Sybil E. Hatch. Reston, Virginia: ASCE Press.
8. Technical Consultant, *Hedy Lamarr and a Secret Communication System*. 2007. Trina Robbins. Mankato, Minnesota. Capstone Press.
9. *Her Story: A Timeline of the Women Who Changed America*. 2008. Charlotte S. Waisman, Ph.D. and Jill S. Tietjen, P.E. New York, New York. HarperCollins.
10. *Keys to Engineering Success* (Chinese language version). 2008. Jill S. Tietjen, Kristy A. Schloss, et.al. Pearson Education, Prentice Hall.
11. Paper (written with Betty Reynolds) titled "Women Engineers Bridging the Gap" reprinted in an anthology titled *Women in Engineering: Pioneers and Trailblazers*. 2009. Margaret E. Layne, PE, editor. Reston, Virginia. American Society of Civil Engineers Press.
12. Profiled in *Stuck: 12 Steps Up the Leadership Ladder*. 2010. Sandra Ford Walston. Charleston, South Carolina.
13. *Her Story: A Timeline of the Women Who Changed America*. 2013 (Paperback and Ebook). Charlotte S. Waisman, Ph.D. and Jill S. Tietjen, P.E. New York, New York. William Morrow.

Technical Reports

1. *RDI's Outlook for Power in the U.S.* (contributing author), Resource Data International, 1998.
2. *Outlook for Power in North America, 1999 Annual Edition* (contributing author), Resource Data International, 2000.
3. *Electric Transmission: Pathway To Power*, Financial Times *Energy*, 2000.
4. Quoted and pictured in the Executive Summary, *Women In Technology Report*, Status of Women and Girls in Colorado, Women's Foundation of Colorado, 2001.

5. *Fuel From the Sky: Solar Power's Potential for Western Energy Supply* (technical writer), National Renewable Energy Laboratory, NREL/BK-550-32160, July 2002.
6. *Using the Fundamentals of Engineering (FE) Examination to Assess Academic Programs*, (with Walter LeFevre, John Steadman, Kenneth White and David Whitman), National Council of Examiners for Engineering and Surveying, 2005.

Articles (Technical)

1. "Transmission Loss Evaluation for Electric Systems" (with Martin W. Gustafson). IEEE 87 SM 467-4, *IEEE Transactions on Power Systems*, 3(3):1026-1032.
2. "Considerations in the Formation of Power Pooling Arrangements" (with Leslie A. Buttorff). 1987. *Public Utilities Fortnightly*, November 26.
3. "The Equivalent Hours Loss Factor Revisited" (with Martin W. Gustafson and Steven S. Mulnix). IEEE 88 WM 166-1, *IEEE Transactions on Power Systems*, 3(4):1502-1507.
4. "Operational Losses Savings Attributable to Load Management" (with Martin W. Gustafson). IEEE 88 SM 659-5, *IEEE Transactions on Power Systems*, 4(1):229-235.
5. "Approximating the System Losses Equation" (with Martin W. Gustafson). 1989. IEEE 89 WM 146-2 — PWRS, *IEEE Transactions on Power Systems*, 4(3):850-855.
6. "Power-System Loss Calculations Are Updated" (with Martin W. Gustafson). 1989. *Transmission and Distribution*, November.
7. "Acid Rain Impacts on Utility Plans for Plant Life Extension." 1990. *Public Utilities Fortnightly*, March.
8. "Making New Rules" (with Michael T. Burr, et al.). 1991. *Independent Energy*, July/August.
9. "The Fair Access Debate." 1991. *Independent Energy*. September.
10. "Direct Water Heater Load Control — Estimating Program Effectiveness Using an Engineering Model" (with Martin W. Gustafson and Gary Epstein). February 1993. IEEE 92 WM 130-5 — PWRS, *IEEE Transactions on Power Systems,* 8(1):137-143.
11. Discussion for "Bulk Transmission System Loss Analysis." Nadira, Wu, Maratukulam, Weber, and Thomas (with Martin W. Gustafson). May 1993. IEEE 92 WM 097-6 — PWRS, *IEEE Transactions on Power Systems*, 8(2):414.
12. "Estimating Air Conditioning Load Control Effectiveness Using an Engineering Model" (with Martin W. Gustafson and Gary Epstein). August 1993. IEEE 92 SM 420-0 PWRS, *IEEE Transactions on Power Systems*, 8(3):972-978.
13. "Communicating the Value of Dispatchability for Nonutility Generation Projects" (with D. Cotcher, K.D. Krauss, and D. Logan). January 1995. IEEE 95 WM 123-0 — PWRS, *IEEE Transactions on Power Systems*.
14. "The perils of power lines: aging infrastructure, aging workforce," *Licensure Exchange,* National Council of Examiner for Engineering and Surveying, April 2006, pp. 7-8.
15. "Pumped Storage Hydro," *The Encyclopedia of Energy Engineering*, Capehart, Barney, Editor, Taylor & Francis Group, LLC, 2007. Updated 2014.
16. "Coal Supply," *The Encyclopedia of Energy Engineering*, Capehart, Barney, Editor, Taylor & Francis Group, LLC, 2007. Updated 2014.
17. "Generation," *The Encyclopedia of Energy Engineering*, Capehart, Barney, Editor, Taylor & Francis Group, LLC, 2007. Updated 2014.
18. "Is There Power in Your Future?" *U.Va. Engineer*, Spring 2007, University of Virginia, p. 17.
19. ""Coal Supply in the U.S. – Surface Mining, *The Encyclopedia of Energy Engineering*, Capehart, Barney, Editor, Taylor & Francis Group, LLC, 2011.
20. "The Interaction of Pumped Storage Hydro and Renewable Energy Resources, *The Encyclopedia of Environmental Management*, Sven Erik Jorgenson, Editor, Taylor & Francis Group, LLC, 2013.

Conference Papers (Technical)

1. "Power by Wire — Expectations and Realities," Proceedings of the Sixth Annual Coal Market Strategies Conference — Dynamics of Utility Coal Use, 2:1-21, Denver, CO, November 1-3, 1988. (Awarded one of 10 best papers for 1988 for Stone & Webster employees.)
2. "Wheeling — Issues and Challenges," Proceedings of the 1989 Electric Utility Business Environment Conference and Exhibition, 101-115, Denver, CO, sponsored by Electric Utilities Consultants, Inc. and RCG/Hagler Bailly, Inc., March 28-30, 1989.
3. "Air Quality Concerns: Impacts on Utility Plans for Life Extension of Coal-Fired Power Plants," Proceedings of the Seventh Annual Coal Market Strategies Conference — Utility Coal Use, Acid Rain, and Other Uncertainties, 3:1-16, Denver, CO, sponsored by Edison Electric Institute Western Coal Council, October 26, 1989. (Awarded one of 10 best papers for 1989 for Stone & Webster employees.)
4. "Transmission Pricing Policies and Access," Proceedings of the 1990 Electric Utility Business Environment Conference and Exhibition, 49-55, Denver, CO, sponsored by Electric Utilities Consultants, Inc. and RCG/Hagler Bailly, Inc., March 7-9, 1990.
5. "Analyzing Utility System Losses." Presented at the T&D World Expo '90, March 1990.
6. "Future Electric Generation: Clean Air At What Cost?" Proceedings of the Fifteenth Annual Conference — Issues in Gas, Electricity, and Telecommunications, 5, July 18-20, 1990. (Awarded one of 10 best papers for 1990 for Stone & Webster employees.)
7. "Transmission Access: Who Pays and How?" Proceedings of the Transmission & Wheeling Conference, 61-70, Denver, CO, sponsored by Electric Utilities Consultants, Inc. and Stone & Webster Management Consultants, Inc., November 8-9, 1990.
8. "Open Access." 1990. Power-Gen '90. November.
9. "Plant Life Management Option Selection Decision Methodology" (with David S. Galpin and Roger L. Johnson). 1990. Power-Gen '90. December.
10. "Why Inter-Area Electric Transmission?" (with Fred E. Depenbrock), Proceedings of the American Power Conference, Volume 53-I, 588-591, Chicago, IL, sponsored by the Illinois Institute of Technology, April 1991.
11. "Decision Methodology for Plant Life Management Option Selection" (with David S. Galpin and Roger L. Johnson), Proceedings of the American Power Conference, Volume 53-I, 485-491, Chicago, IL, sponsored by the Illinois Institute of Technology, April 1991. (Awarded one of 10 best papers for 1991 for Stone & Webster employees.)
12. "Transmission Access: Technical and Political Implications" (with Glenn A. Davidson), Proceedings of the 2nd Annual Transmission & Wheeling Conference, 127-134, Denver, CO, sponsored by Electric Utilities Consultants, Inc. and Stone & Webster Management Consultants, Inc., November 21-22, 1991.
13. "New Transmission Lines: Do We Really Need Them?" (with Glenn A. Davidson). Presented at the Strategic Utility Planning Conference, June 25-26, 1992. (Awarded one of 10 best papers for 1992 for Stone & Webster employees.)
14. "Licensing a Coal-Fired Power Plant in the 1990s — A Utility's Success Story" (with Tom Ohlmacher, Douglas M. Logan, Ludwig Funke, and Scott Carpenter). 1993. Power-Gen '93.
15. "Uncertainty Analysis Without Tears" (with Douglas M. Logan). Proceedings of EPRI's Ninth Electric Utility Forecasting Symposium, September 8-10, 1993.
16. "Modeling Renewable Energy Resources in Utility Planning Models" (with Douglas M. Logan, Alan Taylor, and Peter Lilienthal), Proceedings of the National Regulatory Conference on Renewable Energy, 315-329, Savannah, GA, sponsored by the National Association of Regulatory Utility Commissioners, October 3-6, 1993.
17. "Load Forecasting: Ensuring a Solid Foundation for Integrated Resource Planning" (with Douglas M. Logan and Chris Neil), Proceedings of the Electric Systems Planning and Operations Conference, 1-10, Denver, CO, sponsored by Electric Utilities Consultants, Inc., November 11-13, 1993.

18. "Where and Why Coal Will Remain the Big Player," Proceedings of the Natural Gas and Electric Power Industries Conference, Washington, D.C., sponsored by The Institute of Gas Technology, November 11-13, 1996.
19. "The Chicken or the Egg: Renewables and Transmission," The Fourth Annual Comprehensive Conference on Electric Energy Markets, Regulation and Investment, Law Seminars International, Washington, DC, March 4, 2008.

Technical Presentations

1. "The Mechanical Performance of Polyglycolic Acid Sutures." Presented to the Virginia Academy of Science, May 1975.
2. "Mechanical Performance of Surgical Sutures." Presented at the American Society of Mechanical Engineers Regional Student Conference, March 1976. (Awarded second place.)
3. "How to Evaluate Utility Staff Resource Plans" (with Martin W. Gustafson). Presented to the California Municipal Utilities Association, February 1987.
4. "Geothermal Project Development and Management Market Analysis," (with Leslie A. Buttorff), presented to the Geothermal Resources Council as part of a short course, Sparks, NV, October 9-10, 1987.
5. "Transmission Access and Wheeling." Presented at the Rocky Mountain Electrical League Spring Conference, May 1990.
6. "Engineering and Rate Making Fundamentals," Power Transmission: Access, Pricing and Regulation, San Francisco, CA, presented to Infocast, Inc., September 23, 1991.
7. "Coal Issues and Electric Fuel Management." Stone & Webster Management Consultants' annual Utility Management Development Program, Annual lecture, 1986-1992.
8. "Natural Gas and Coal: Competition or Cooperation?" Presented at Denver Coal Club. February 11, 1993.
9. "Where are We and How Did We Get There?" 32nd Annual Paul D. Scholz Symposium on Technology and Its Role in Society, University of Iowa, Iowa City, Iowa, April 5, 2001.
10. "What is Happening in California?" Englewood (Colorado) Lions Club, Englewood, CO, June 19, 2001.
11. Transmission 101: Understanding the Grid," Coal Market Strategies 2001 – Fueling the Nation's Energy Needs: Bridging the Barriers to Future Coal-fired Power," San Antonio, Texas, October 15-17,. 2001.
12. "Powering Our Future," Boulder Rotary Club, Boulder, CO, January 4, 2002.
13. "Electrical Power in 2004 and Beyond, Sharkey, Howes & Javer, Inc., Denver, CO, May 12, 2004.
14. "Blackouts, Wind Turbines and Coal: Where is the Power in Your Future?" IEEE and SWE, Clemson University, Clemson, SC, October 6, 2004.
15. "Integrated Resource Planning in the 21st Century" (with Jacqueline C. Sargent), Rocky Mountain Electrical League 2005 Spring Conference, Albuquerque, NM, May 16, 2005.
16. "Small is Profitable: Distributed Generation and the Aging Electric Infrastructure in the U.S.," (with Kitty Wang), Society of Women Engineers National Conference, Anaheim, California, November 4, 2005.
17. Panel Member, Environment and Sustainability, University of Virginia Women in Leadership Conference, Charlottesville, Virginia, September 26, 2008.
18. "Fitting Wind into Utility Resource Portfolios," Women of Wind Energy, Denver, Colorado, June 9, 2010.
19. "Resource Planning for an Aging Coal Fleet," RMEL Fall Convention, Marana, Arizona, September 8-10, 2013.

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2011-2030 Integrated Resource Plan
for
Black Hills Power

2011

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ES.0 Executive Summary

ES.1 Summary

The 2011 Black Hills Power (BHP) integrated resource plan (IRP) was completed to provide a road map for defining the appropriate generation system upgrades, modifications, and additions required to ensure reliable and economic service to BHP's customers now and for the future. The IRP examined the needs of those customers with a consideration of existing demand-side and future supply-side resources, including renewable energy and purchased power.

Key elements of the IRP include an evaluation of the current and expected future resource planning environment, identification of resource needs for the next 20 years through a comprehensive resource need assessment process, and an action plan that identifies the steps required to implement a preferred portfolio of incremental resources to meet the forecasted need. Development of the IRP involved consideration of cost, risk, uncertainty, supply reliability, and public policy. As a result, the preferred plan reflects energy efficiency and demand-side management goals, the effect of environmental regulations, gas-fired combined-cycle combustion turbine technology and firm market purchases.

The preferred plan meets the objectives of the company to:

- Ensure a reasonable level of price stability for its customers
- Generate and provide reliable and economic electricity service while complying with all environmental standards
- Manage and minimize risk
- Continually evaluate renewables for our energy supply portfolio, being mindful of the impact on customer rates.

In preparing this IRP, BHP conformed to the Wyoming Public Service Commission Guidelines Regarding Electric IRPs, including hosting a stakeholder meeting on Monday, May 16, 2011, in Rapid City, South Dakota. The comments and feedback provided during the meeting were incorporated in the IRP analysis, as appropriate. None of the comments or feedback had a material impact on the IRP process or final results.

ES.2 Action Plan

BHP's action plan listed below provides a template for the actions that should be taken over the next several years. BHP should continue to monitor market conditions and regulatory developments so that the items in the action plan can be adapted to address actual conditions as they occur. BHP's plan is as follows:

- In the near term, continue to purchase a firm 6 x 16 (6 days each week, 16 hours each day) product during the summer months to provide for the summer capacity shortfall.

- Purchase or otherwise obtain a simple cycle combustion turbine to be converted to combined cycle operation in 2014.
- Seek opportunities to develop economic renewable resources – particularly wind and solar.
- Actively review development of load growth opportunities in the service territory.
- Monitor transmission developments in the Western U.S.

ES.3 Company Background

BHP serves approximately 68,000 customers in 25 communities located in Western South Dakota, Northern Wyoming, and Southeastern Montana. In 2010, BHP sold more than 3,315 GWh of electricity through retail sales, contract wholesales sales and off-system wholesales sales. On January 31, 2011, BHP's system recorded an all-time winter system peak of 408 MW and on July 19, 2011, hit an all-time summer system peak of 452 MW. BHP currently meets electric demand through purchases from the open market, power purchase agreements (PPA) and generation assets.

BHP's power delivery system consists of approximately 565 miles of transmission lines (greater than 69 kV) and 2,930 miles of distribution lines (69 kV or lower). BHP also owns 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids. This transmission tie provides transmission access to both the Western Electricity Coordinating Council (WECC) region in the West and the Mid-Continent Area Power Pool (MAPP) region in the East.

BHP has firm point-to-point transmission access to deliver up to 50 MW of power on PacifiCorp's transmission system to wholesale customers in the Western region through 2023. BHP also has firm network transmission access to deliver power on PacifiCorp's system to Sheridan, Wyoming to serve its power sales contract with Montana-Dakota Utilities (MDU).

In addition, BHP has entered into four long-term power sales agreements:

- an agreement with MDU to supply energy needs above their Wygen III ownership share, and replace their Wygen III ownership share when Wygen III is operating at a reduced capacity or off line
- an agreement with the City of Gillette to dispatch the City's 23% of Wygen III's net generating capacity and their operating component of spinning reserves
- a unit contingent agreement that supplies a decreasing amount of energy and capacity to Municipal Energy Agency of Nebraska (MEAN) under a contract that expires in 2023
- a five-year power purchase agreement (PPA) with MEAN for the purchase of 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III.

BHP's future resource need has historically been evaluated in conjunction with its Black Hills Corporation affiliate Cheyenne Light, Fuel & Power (Cheyenne Light). In 2005, BHP and Cheyenne Light completed a joint resource plan included in a Certificate of Public Convenience and Necessity (CPCN) before the Wyoming Public Service Commission (WPSC) for the construction of the coal-fired Wygen II unit. The need for Wygen II was deemed necessary to serve Cheyenne Light's load, and is a Cheyenne Light rate-based resource. In 2007, BHP and Cheyenne Light completed a joint resource plan included in a CPCN before the WPSC for the construction of the coal-fired Wygen III unit. The need for Wygen III was deemed necessary to serve BHP's load, and is a BHP rate-based resource. BHP's 2011 IRP is the first plan since the mid-1990s that exclusively analyzes the future resource needs of BHP's customers.

ES.4 The Planning Environment

Planning for future generating resources in the electric utility industry involves the consideration and evaluation of many uncertainties. Those uncertainties have increased in number and magnitude over the last several decades. BHP has considered the impacts of uncertainties that include the future of coal-fired generation, grid modernization, plug-in hybrid electric vehicles, and renewable energy standards. The uncertainties regarding the future of coal-fired generation include climate change legislation, carbon capture and sequestration technologies, and other environmental regulatory requirements. Changes in the market that could result from the construction of new transmission also need to be monitored.

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. This rule provided for hazardous air pollutant-related emission limits and monitoring requirements for area sources of hazardous air pollutants. BHP is evaluating the impact of the rules on its existing generating facilities. The Area Source Rules as issued have a significant impact on our Neil Simpson I, Osage and Ben French coal-fired facilities, which have collectively provided approximately 71 MW summer of summer capacity. The regulation has prompted BHP to perform an engineering evaluation to determine economic viability of continued operations of these units. Based on the evaluations completed, the cost associated with complying with the Area Source Rules and other environmental regulations may lead to retirement of these units prior to March 21, 2014.

Wyoming does not currently have a renewable energy standard. South Dakota has adopted a renewable portfolio objective that encourages utilities to generate, or cause to be generated, at least 10% of their retail electricity supply from renewable energy sources by 2015. Absent a specific renewable energy mandate in Wyoming or South Dakota, our current strategy is to prudently incorporate renewable energy into our resource supply, seeking to minimize associated rate increases for our utility customers.

ES.5 Assumptions

A wide variety of data assumptions must be made for IRP modeling. A 20-year planning horizon was used as the basis for the modeling assumptions. Other key assumptions include the load forecast, coal price forecasts, natural gas price forecasts, market price forecasts, financial parameters, planning reserves, and emissions costs.

ES.6 Demand-Side Management

BHP's demand-side management programs as defined in Docket # EL11-002 were approved by the South Dakota Public Utilities Commission (SDPUC) on June 28, 2011. The plan includes residential and commercial programs for energy efficiency. The residential electric portfolio offers opportunities to save energy with water heating, refrigerator recycling, heat pumps, and school-based energy efficiency. This portfolio also offers energy audits and weatherization programs. The commercial electric portfolio provides both a prescriptive rebate program and a custom rebate program.

ES.7 Supply-Side Resources

The resources currently available to BHP to meet customer obligations include coal-fired units, natural gas-fired units, diesel-fired units, and long-term PPAs. The following are the long-term PPAs and generation assets presently used to meet BHP's customer capacity needs.

- Pacificorp PPA, referred to as Colstrip, expiring in 2023, with a total net capacity of 50 MW
- Happy Jack and Silver Sage Wind Farm PPAs expiring in 2028 and 2029, respectively, for a total accredited capacity of 3.5 MW
- Five coal-fired power plants with a total net capacity of 280 MW
- One diesel station with a net capacity of 10 MW
- Three natural gas-fired combustion turbine stations with a combined net capacity of 178 MW

As part of the IRP modeling, both conventional and renewable resources were considered to replace any retiring units or expiring PPAs and to provide for future load growth. Conventional resources included coal, natural gas-fired combined cycle units (CC), natural gas-fired combustion turbines (SC or CT), firm market power, conversions of existing combustion turbines to combined cycle units, upgrades to existing units, and existing generation purchases. The renewable resources considered included solar and wind.

ES.8 Resource Need Assessment

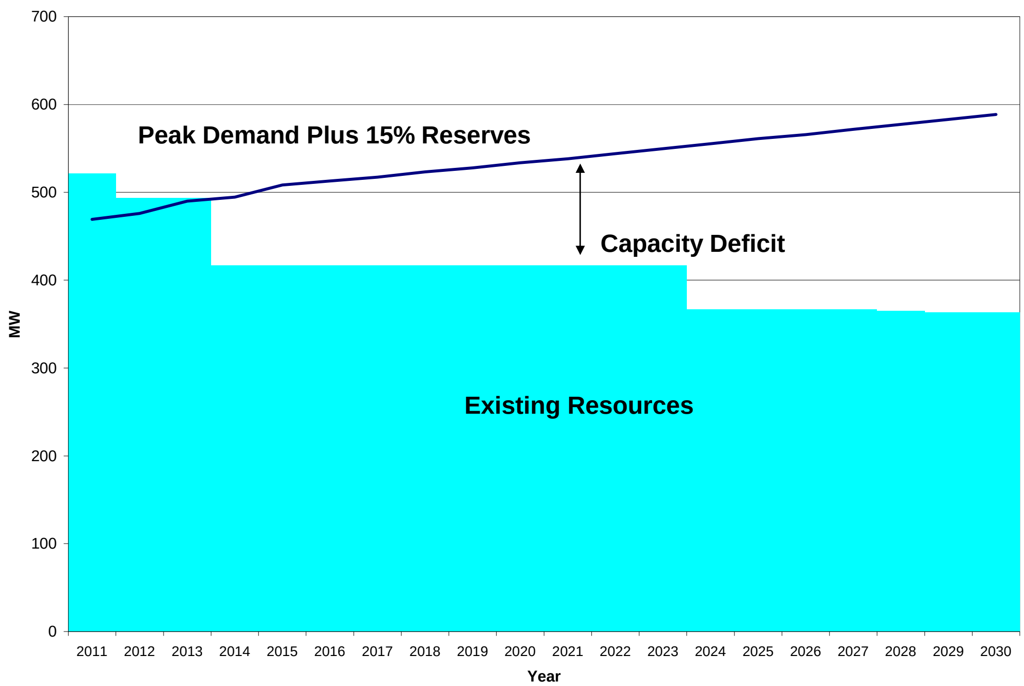
The EPA Area Source Rules have an impact on BHP's Ben French, Neil Simpson 1, and Osage coal-fired generation units. Currently, the Osage units are in cold storage based on economics and are not included as part of BHP's available resources, but Ben French and

Neil Simpson are in operation and relied upon for system capacity. BHP's future resource need is based on the upgrade or replacement of the Ben French and Neil Simpson 1 units.

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. The PPAs with PacifiCorp, Happy Jack, and Silver Sage all terminate over the planning horizon for a loss of 53.5 MW of accredited capacity.

As resources retire or existing PPAs terminate, other resources will be required to enable BHP to meets 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 ES-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". BHP's capacity deficit in 2014 is approximately 66 MW and reaches approximately 225 MW by the end of the planning horizon.

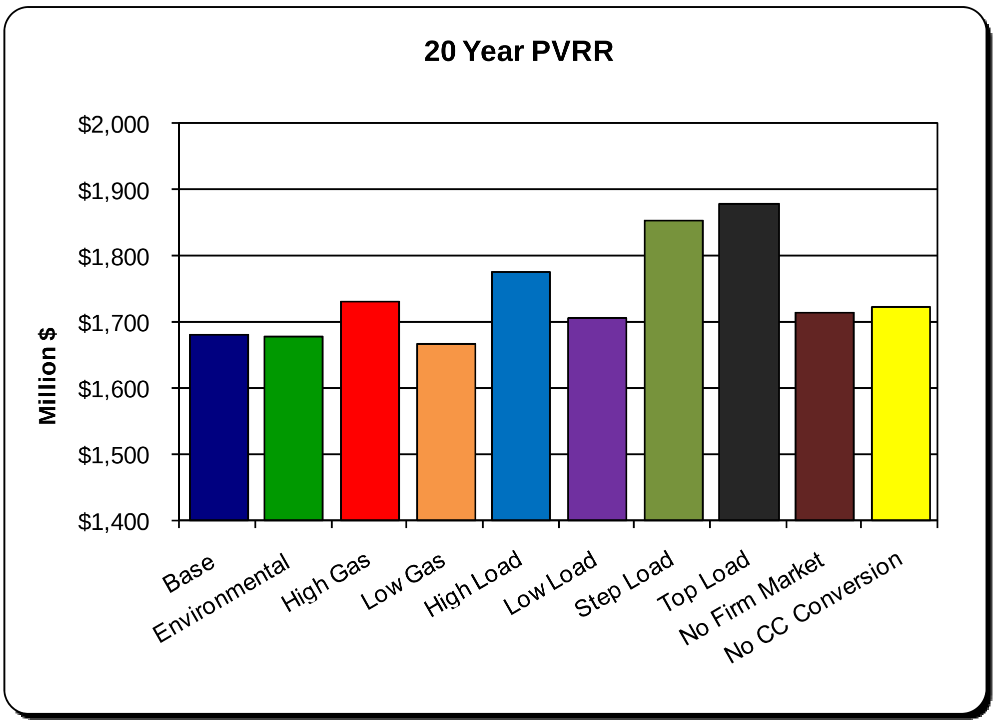
Figure ES-1
Black Hills Power Load and Resource Summary



ES.9 Resource Evaluation

The process used to determine the preferred resource portfolio for BHP began by identifying ten scenarios, also referred to as plans, to run through the Capacity Expansion module.[1] These scenarios were determined to measure risk associated with some of the modeling assumptions and to capture some potential load additions above what is forecast in a typical year. Each capacity expansion model scenario selected an economic resource portfolio to serve the load subject to the assumptions of that scenario. The resource portfolios were each run through a production cost model, and were modeled with the base case scenario assumptions to determine the relative present value of revenue requirements (PVRR). The PVRR for all ten scenarios when run on a deterministic basis (each scenario run using the base case assumptions) are shown on Figure ES-2.

Figure ES-2
Deterministic PVRR for Scenarios



ES.10 Risk Analysis

Utilities must plan for future customer needs for electricity in an environment of significant uncertainty. Thus, the analysis conducted for this IRP examined uncertainty under a variety of possible future conditions. Analyses conducted to quantify the risk associated with the various scenarios included stochastic analysis, and specific examination of 1) the effects of a step load increase in the BHP demand for electricity, and 2) the effects of not having a market available for economy interchange on the base plan.

Ventyx is a leading provider of software, data and advisory services to several industries, including utility companies. Ventyx has developed utility specific software to assist

[1] Specific details for each scenario are provided in Section 7.1 of this report.

utilities in evaluating generation resource needs and was retained by BHP to assist in the IRP process. Ventyx's Strategic Planning model uses a structural approach to forecasting prices that captures the uncertainties in demand, fuel prices, supply and costs. The uncertainties examined in this IRP included those reflected in Table ES-1 which shows the minimum and maximum values used for selected uncertainty values.

Table ES-1
Ranges for Selected Uncertainty Variables

Variable	Minimum	Maximum
Mid-Term Peak	0.87	1.11
Mid-Term Energy	0.90	1.09
Long-Term Demand	0.85	1.12
Mid-Term Gas	0.70	2.60
Oil Price	0.85	1.18
Long-Term Gas	0.79	1.23
Coal Unit Availability	0.88	1.11
Gas Unit Availability	0.80	1.16
Pulverized Coal Capital Costs	1.00	1.15
Combustion Turbine Capital Costs	1.00	1.10
Combined Cycle Capital Costs	1.00	1.10
Wind Capital Costs	0.90	1.10

Source: Ventyx

Cumulative probability distributions, also known as risk profiles, provide the ability to visually assess the risks associated with a decision under uncertainty. These risk profiles are one of the results of the stochastic analysis conducted by Ventyx for BHP. The risk profiles for the scenarios examined with the exception of the step load scenarios are shown on Figure ES-3.

Figure ES-3
Scenarios – Risk Profiles (2011-2030)

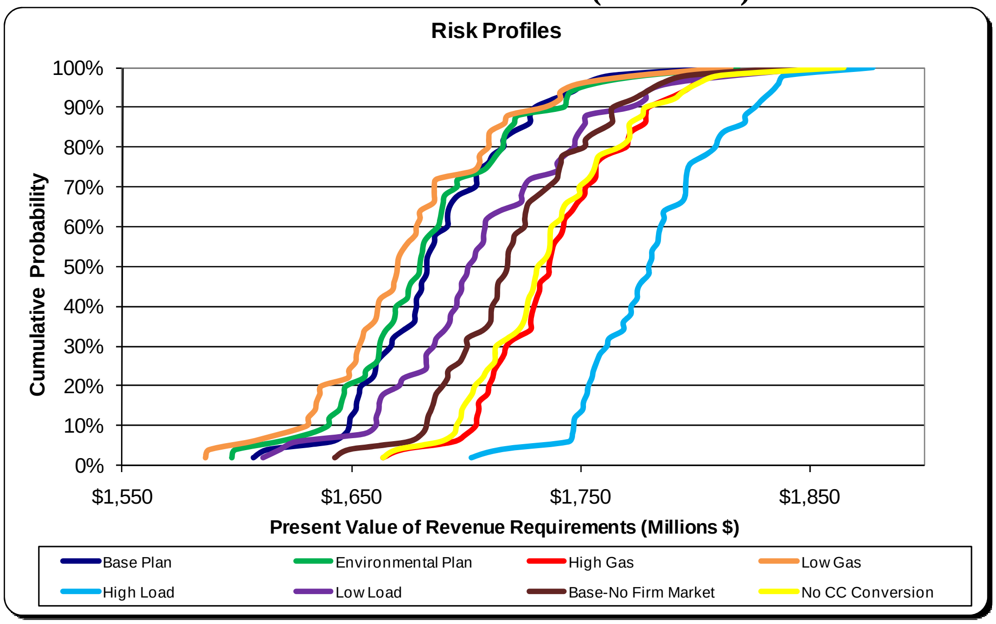
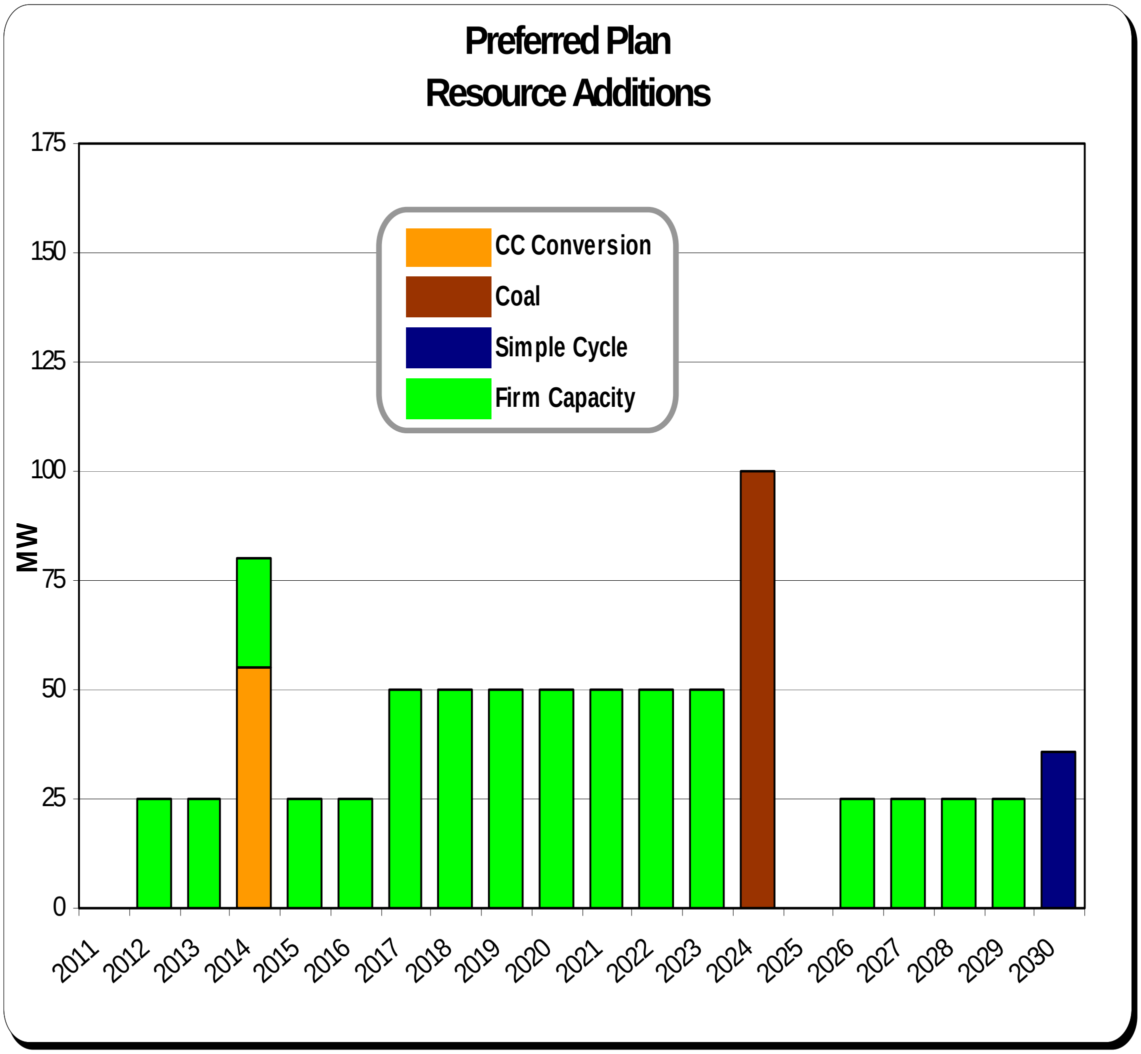


Figure ES-3 shows that with the exception of the low gas and the environmental scenarios, the risk profile for the base plan is to the left and lower than any other case. The base plan resource portfolio includes the conversion of an existing simple cycle gas turbine to a combined cycle unit in 2014 and firm capacity in all of the years 2011-2023. Because of capacity additions in the later years of the base plan (referred to as end effects) that do not occur in the environmental scenario, the base plan's risk profile is somewhat higher than the risk profile for the environmental scenario for the 20 years of the planning horizon. Any decision for resources at the end of the planning horizon is many years in the future, and will be evaluated in a future resource plan. Thus the base plan has been selected as the preferred plan. The resource portfolio for the preferred plan is shown in Figure ES-4.

Figure ES-4



ES.11 Conclusion

This IRP provides a road map to define the system upgrades, modifications, and additions that are required to ensure reliable and economic service to BHP's customers now and into the future. The resources selected in the preferred plan balance cost with the need to mitigate risk and provide for operational flexibility for BHP. BHP's preferred portfolio addresses the generation needs of its customer over the short term – the next 5 years - through the implementation of energy efficiency and demand-side management goals, installation of gas-fired combined-cycle combustion turbine technology and firm market purchases. The preferred plan, when adjusted for end effects, is the least cost plan and has low risk associated with future uncertainty. This plan also provides BHP with an efficient combined cycle gas turbine. The need for resources in the longer term will be re-examined in future IRPs.

The preferred plan meets the objectives of the company to:

- Ensure a reasonable level of price stability for its customers
- Generate and provide reliable and economic electricity service while complying with all environmental standards
- Manage and minimize risk
- Continually evaluate renewables for our energy supply portfolio, being mindful of the impact on customer rates.

1.0 Introduction

1.1 Background

Black Hills Power (BHP) serves 68,000 customers in 25 communities located in Western South Dakota, Northern Wyoming, and Southeastern Montana. In 2010, BHP sold more than 3,315 GWh of electricity through retail sales, contract wholesales sales and off-system wholesale sales. BHP currently meets electric demand through purchases from the open market and from the following power purchase agreements (PPA) and generation assets:

- PacifiCorp PPA expiring in 2023, which provides for the purchase of 50 MW of coal-fired baseload power;
- Reserve Capacity Integration Agreement (RCIA) with PacifiCorp expiring in 2012, which makes available 100 MW of reserve capacity in connection with the utilization of the Ben French CT units;
- Cheyenne Light and BHP's Generation Dispatch Agreement that requires BHP to purchase all of Cheyenne Light's excess energy (Cheyenne Put);
- Happy Jack and Silver Sage Wind Farm PPAs expiring in 2028 and 2029, respectively, for an accredited capacity of 3.5 MW
- Five coal-fired power plants with a total net capacity of 280 MW
- One diesel station with a net capacity of 10 MW
- Three natural gas-fired combustion turbine stations with a combined net capacity of 178 MW

BHP's power delivery system consists of approximately 565 miles of transmission lines (greater than 69 kV) and 2,930 miles of distribution lines (69 kV or lower). Black Hills Power also owns 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids. This transmission tie provides transmission access to both the Western Electricity Coordinating Council (WECC) region in the West and the Mid-Continent Area Power Pool (MAPP) region in the East.

BHP has firm point-to-point transmission access to deliver up to 50 MW of power on PacifiCorp's transmission system to wholesale customers in the Western region through 2023. BHP also has firm network transmission access to deliver power on PacifiCorp's system to Sheridan, Wyoming to serve its power sales contract with Montana-Dakota Utilities (MDU) through 2017, with the right to renew pursuant to the terms of PacifiCorp's transmission tariff.

In addition, BHP has entered into four long-term power sales agreements:

- In conjunction with MDU's April 2009 purchase of a 25% ownership interest in Wygen III, an agreement to supply 74 MW of capacity and energy through 2016 was modified. Sales to MDU have been integrated into Black Hills Power's control area and are considered part of its firm native load. Capacity from the

Wygen III unit is deemed to supply a portion of the required 74 MW. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from BHP's other generation facilities or from system purchases with reimbursement of costs by MDU;

- BHP's agreement with the City of Gillette is to dispatch the City's 23% of Wygen III's net generating capacity for the life of the plant. Upon the City of Gillette's July 2010 purchase of a 23% ownership interest in Wygen III, a seven-year PPA with the City of Gillette that went into effect in April 2010, was terminated. The City of Gillette's 23 MW of Wygen III capacity has been integrated into BHP's control area and is considered part of its firm native load. During periods of reduced production at Wygen III, or during periods when Wygen III is off line, BHP will provide the City of Gillette with its first 23 MW from BHP's other generation facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, BHP will also provide the City of Gillette its operating component of spinning reserves;
- BHP has entered into an agreement to supply 20 MW of energy and capacity to Municipal Energy Agency of Nebraska (MEAN). This contract is unit-contingent based on the availability of the Neil Simpson II and Wygen III plants, with capacity purchases decreasing to 15 MW in 2018, 12 MW in 2020 and 10 MW in 2022. This contract expires in 2023.
- BHP's five-year PPA with MEAN which commenced in May 2010 whereby MEAN will purchase 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III.

BHP's future resource need has historically been evaluated in conjunction with its Black Hills Corporation affiliate Cheyenne Light, Fuel & Power (Cheyenne Light). In 2005, BHP and Cheyenne Light completed a joint resource plan included in a Certificate of Public Convenience and Necessity (CPCN) before the Wyoming Public Service Commission (WPSC) for the construction of the coal-fired Wygen II unit. The need for Wygen II was deemed necessary to serve Cheyenne Light's load, and is a Cheyenne Light rate-based resource. In 2007, BHP and Cheyenne Light completed a joint resource plan included in a CPCN before the WPSC for the construction of the coal-fired Wygen III unit. The need for Wygen III was deemed necessary to serve BHP's load, and is a BHP rate-based resource. BHP's 2011 IRP is the first plan since the mid-1990s that exclusively analyzes the future resource needs of BHP's customers.

Since the 2007 IRP was completed, several important changes have occurred in the electric utility industry:

- While natural gas prices continue to be volatile, the recent emergence of shale gas has introduced relative stability into natural gas pricing. However, there is much for the industry to learn with respect to the future of shale gas production and its expected influence on future natural gas pricing.
- Just a few years ago, the enactment of carbon cap and trade or a similar carbon reduction program appeared imminent; in mid 2011 that no longer appears to be

the case. Such enactment is exceedingly dependent on politics and the development of laws and public policy in Washington, DC.
- Clean Air, boiler Maximum Achievable Control Technology (MACT) and other regulations promulgated by the Environmental Protection Agency (EPA), are expected to cause the retirement of small coal-fired units on the BHP system. Other small coal-fired units around the country are also being affected.
- The effects of the earthquake and tsunami in Japan in March 2011 are expected to impact market prices for electricity over the planning horizon and eventually impact the operation of existing and planned nuclear units in the U.S.

1.2 Objectives

The IRP was completed to provide a road map for defining the appropriate system upgrades, modifications, and additions required to ensure reliable and economic electric service to BHP's customers now and for the future. This IRP addresses resource needs for BHP for the planning horizon of 2011-2030. The IRP examined the needs of those customers with a thorough consideration of generation resources, including renewable energy and short-term purchased power.

Prudent utility practices were employed in the preparation of the IRP and a full range of practical resource alternatives, including renewables, were evaluated. Comprehensive modeling was undertaken using Ventyx *Capacity Expansion* and *Strategic Planning powered by MIDAS Gold®* software modules (see Appendix A). The Ventyx modeling included 1) optimization of resource selection using linear programming techniques, 2) in-depth modeling of resource portfolios using production costing models, and 3) risk analysis using stochastic techniques.

The preferred plan meets the objectives of the company to:

- Ensure a reasonable level of price stability for its customers
- Generate and provide reliable and economic electricity service while complying with all environmental standards
- Manage and minimize risk
- Continually evaluate renewables for our energy supply portfolio, being mindful of the impact on customer rates.

1.3 IRP Process

In preparing this IRP, BHP conformed to the Wyoming Public Service Commission Guidelines Regarding Electric IRPs, including hosting a stakeholder meeting on Monday, May 16, 2011, in Rapid City, South Dakota. The comments and feedback provided during the meeting were incorporated in the IRP analysis, as appropriate. None of the comments or feedback had a material impact on the IRP process or final results.

2.0 Planning Environment

Planning for future generating resources in the electric utility industry involves the consideration and evaluation of many uncertainties. Those uncertainties have increased in number and magnitude over the last several decades. BHP has considered the impacts of uncertainties that include the future of coal-fired generation, grid modernization, plug-in hybrid electric vehicles, and renewable energy standards. The future of coal-fired generation discussion touches on climate change legislation, carbon capture and sequestration technologies, and environmental regulatory requirements.

2.1 The Future of Coal-Fired Generation

For many years, most of the baseload energy need in this country has been provided by coal-fired generation. As a fuel, coal has many merits:

- it is dense (meaning it has a high heating value in a compressed space)
- there are extensive and efficient supply chains that have been built over its many years of use
- it is relatively low cost and has experienced much less price volatility than other fuels, particularly natural gas.

Coal is also quite abundant in this country and in Wyoming (the estimated supply is measured in hundreds of years), helping to ensure national energy security. Over the years, Black Hills Corporation (BHC) has implemented cutting edge technologies for its coal-fired power plants. Lack of water in the Gillette, Wyoming area led BHP to become a pioneer in the installation and operation of air-cooled condensers. BHP has partnered with Babcock & Wilcox, the Energy & Environmental Research Center of the University of North Dakota, Optimal Air Testing, and the University of Wyoming on studies examining methods of controlling mercury emissions when coal is used as a combustion fuel. BHP was the first adopter of low NO_x (nitrogen oxides) burners which were retrofitted on Neil Simpson I in the early 1990s to control nitrous oxide emissions. Since that time Neil Simpson II has been retrofitted with the latest design low NO_x burners, and Black Hills Wyoming's and Cheyenne Light's coal generating units Wygen I and Wygen II have also been equipped with low NO_x burners. In addition, BHP agreed to test burn coal produced by a company that worked on a clean coal process in order to assist in the understanding of the environmental and operational merits of that process. BHC has striven to ensure that its plants use the best available control technologies when constructed and comply with all permit emission limits. These control technologies include Selective Catalytic Reactors (SCR) for NO_x control, Spray Dry Absorption (SDA) for SO_2 controls, Electrostatic Precipitators (ESP) and fabric filter baghouses for particulate matter control. We are currently testing sorbent injection products (Powder Activated Carbon-PAC/Novinda Sorbent/Calcium Chloride) for mercury and other hazardous air pollutant control at our coal facilities. Control technologies at our new combustion turbine projects will include SCR (NO_x control) and Catalytic Oxidation control carbon monoxide (CO) and volatile organic chemical (VOC). Utilizing pipeline quality natural gas will reduce particulate matter, SO_2, hazardous air pollutants, and greenhouse gases in the combustion process as compared to other conventional fuels. These control technologies will enhance the ambient air we breathe, increase visibility (Regional Haze) at our National Parks, reduce Acid Rain (SO_2/NO_x), ground level Ozone (NO_x), and reduce hazardous air pollutants (mercury, other metals and acids).

One of the newer issues surrounding coal as a fuel for electricity generation is that it produces more carbon dioxide (CO_2) emissions per unit of energy output than any other fuel – about twice as much as natural gas. Today the future of coal-fired generation for electric utilities is significantly uncertain. Coal faces competitive pressure from natural gas in the short term and in the long term from renewable resources or other emerging technologies. But coal plants continue to be built in developing nations particularly China. Some sources report that China is on the average adding one new coal plant per week.

It took many decades to build the current infrastructure of coal-fired power plants in the United States, so existing coal-fired generation will continue to be a large producer of energy during the 20-year planning horizon of this IRP and beyond. Carbon capture and sequestration (CCS) has yet to be proven on a commercial scale and may or may not be practical in any given location depending on the geology at the site or cost limitations to deliver it where it could be used.

As a result of potential greenhouse gas legislation, this IRP considers environmental costs (which include possible CO_2 costs) as a critical uncertain factor. As a result of the uncertainty of the future of coal-fired generation, some alternate plans assume that no future new coal-fired units will be built during the planning horizon.

2.1.1 Climate Change Legislation

The effects of greenhouse gases on the atmosphere and on the Earth's climate have been a subject of debate in the U.S. and worldwide for many years. On May 19, 2010, the National Research Council, an arm of the National Academies, issued three reports that concluded global climate change is occurring and that it is caused in large part by human activities. The reports recommend some form of carbon pricing system as the most cost-effective way to reduce emissions. The reports suggest that cap-and-trade, taxing emissions or some combination of the two could provide the needed incentive to reduce the carbon emissions. The reports further state that major technological and behavioral changes will be required, and that business as usual will not address the climate change issue. Among those changes, the reports recommend the capturing and sequestering of CO_2 from power plants and factories as well as scrubbing CO_2 directly from the atmosphere.

How these reports will be translated into regulation and laws at the local, state and national levels remain to be seen, continuing this uncertainty in the planning period of BHP's IRP. BHP cannot predict if any particular carbon mitigation strategy will be enacted into law or when such might occur. The Spring 2011 Reference Case from

Ventyx no longer includes carbon costs in its base case. However, BHP did consider levels of potential carbon regulation in the future in its risk analysis of this IRP.

2.1.2 Carbon Capture and Sequestration Technologies[2]

Carbon capture and sequestration (CCS) technologies are currently being researched and tested in an effort to remove CO_2 from the atmosphere. Carbon capture is defined as the separation and entrapment of CO_2 from large stationary sources including power plants, cement manufacturing, ammonia production, iron and non-ferrous metal smelters, industrial boilers, refineries, and natural gas wells. Carbon sequestration means the capture and secure storage of CO_2 that would otherwise be emitted to or remain in the atmosphere. CO_2 can also be removed from the atmosphere through what is termed "enhancing natural sinks" by increasing its uptake in soils and vegetation (reforestation) or in the ocean (iron fertilization). Additional information on CCS is found in Appendix C.

With the belief that CO_2 will be regulated (either cap and trade or a tax) with an associated requirement to significantly reduce CO_2 emissions in the future, CCS will need to be proven as a viable technology in order for coal-fired generation to continue to be a resource option.

For purposes of this IRP, BHP assumed CCS has not progressed enough to be a viable alternative for this IRP during the entire twenty-year planning horizon.

2.1.3 Environmental Regulatory Requirements

BHP personnel are closely monitoring environmental regulations and requirements to determine what actions need to be undertaken to ensure compliance and to understand the costs associated with that compliance. Among other issues, BHP is currently tracking issues relating to ozone; sulfur dioxide (SO_2); nitrogen dioxide (NO_2); the boiler Maximum Achievable Control Technology (MACT) rules for both industrial sources and utility boilers; the Clean Air Interstate Rule (CAIR) and its impending replacement rule, the Clean Air Transport Rule (CATR); water; particulate matter, specifically for 2.5 micrometers ($PM_{2.5}$); the Coal Combustion Residuals (CCR) rule relating to ash; mercury and hazardous air pollutants (Hg/HAPS); and Geenhouse Gases , (see Figure 2-1[3]).

The uncertainty related to the myriad of rules expected from the U.S. Environmental Protection Agency (EPA) is large. The American Public Power Association (APPA) projects that the coal-fired power sector will see near-constant retrofits from 2012 through 2018, competition for scarce engineering and construction services and equipment, large-scale unit retirements, possible shortfalls in reserve margin

[2] Howard Herzog and Dan Golomb, "Carbon Capture and Storage from Fossil Fuel Use," as published in the *Encyclopedia of Energy*, 2004.
[3] "Generating Buzz," *Power Engineering*, July 2010, p. 80.

requirements, an increase in natural gas generation, and a worrisome chance that financial resources could be misallocated and investments left stranded.[4]

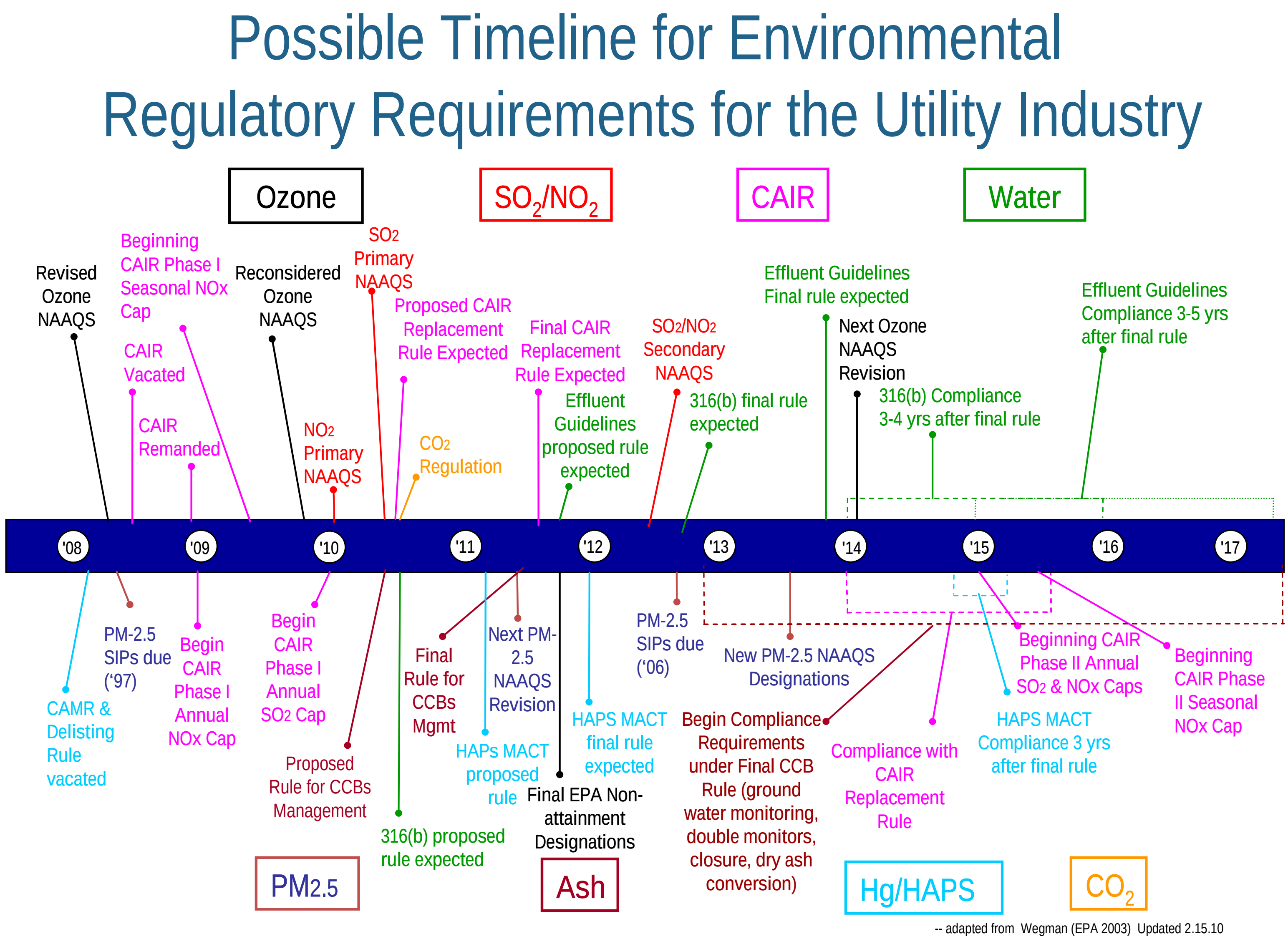
APPA believes that the EPA hopes to force closure of 50% of the fleet of coal-fired generating units in the U.S. in the next 10 years which would reduce the CO_2 emissions by a commensurate 50%. The cost of such a transition is in the hundreds of billions of dollars.[5]

The 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. This rule provides for hazardous air pollutant-related emission limits and monitoring requirements for area sources of hazardous air pollutants. BHP is evaluating the impact of the rules on its existing generating facilities. The area source rules, as issued, have a significant impact on our Neil Simpson I, Osage and Ben French coal-fired facilities. The regulation has prompted BHP to perform engineering evaluations to determine economic viability of continued operations of these units. In our current opinion, the regulations will lead to retirement of these units within three years of the effective date of the final rule.

BHP previously placed its Osage 1-3 units in cold storage based on economics. The evaluation of the upgrades necessary to bring Ben French and Neil Simpson 1 into compliance with the Area Source Rules and the cost associated with those upgrades have been completed. If it is determined that upgrading these units is not economically viable then it is probable that the Ben French, Neil Simpson 1, and Osage 1-3 units will be retired in 2014.

[4] Eric Wagman, "Expect a Mess as EPA Rules Take Hold," *Power Engineering*, July 2010, p. 4.
[5] Ibid.

Figure 2-1


Possible Timeline for Environmental Regulatory Requirements for the Utility Industry
Ozone
SO2/NO2
CAIR
Water
Revised Ozone NAAQS
Beginning CAIR Phase I Seasonal NOx Cap
CAIR Vacated
CAIR Remanded
Reconsidered Ozone NAAQS
NO2 Primary NAAQS
SO2 Primary NAAQS
Proposed CAIR Replacement Rule Expected
CO2 Regulation
Final CAIR Replacement Rule Expected
Effluent Guidelines proposed rule expected
SO2/NO2 Secondary NAAQS
316(b) final rule expected
Effluent Guidelines Final rule expected
Next Ozone NAAQS Revision
316(b) Compliance 3-4 yrs after final rule
Effluent Guidelines Compliance 3-5 yrs after final rule
'08
'09
'10
'11
'12
'13
'14
'15
'16
'17
CAMR & Delisting Rule vacated
PM-2.5 SIPs due ('97)
Begin CAIR Phase I Annual NOx Cap
Begin CAIR Phase I Annual SO2 Cap
Proposed Rule for CCBs Management
316(b) proposed rule expected
Final Rule for CCBs Mgmt
HAPs MACT proposed rule
Next PM-2.5 NAAQS Revision
Final EPA Non-attainment Designations
HAPS MACT final rule expected
PM-2.5 SIPs due ('06)
New PM-2.5 NAAQS Designations
Begin Compliance Requirements under Final CCB Rule (ground water monitoring, double monitors, closure, dry ash conversion)
Compliance with CAIR Replacement Rule
HAPS MACT Compliance 3 yrs after final rule
Beginning CAIR Phase II Annual SO2 & NOx Caps
Beginning CAIR Phase II Seasonal NOx Cap
PM2.5
Ash
Hg/HAPS
CO2
-- adapted from Wegman (EPA 2003) Updated 2.15.10

2.2 Grid Modernization

Grid modernization, sometimes referred to as "Smart Grid", is frequently used in discussions among government agencies, equipment manufacturers, and the utility industry. However, the definition of grid modernization varies significantly depending on who is leading the discussion. For BHP's purposes in preparing this IRP, grid modernization will mean integrating the electrical infrastructure with the communications network. This will lead to an automated electric power system that monitors and controls grid activities, ensuring two-way flow of electricity and information between power plants and consumers – and all points in-between. Additional information on grid modernization can be found in Appendix D.

BHP has completed installation of advanced metering infrastructure (AMI) on the majority of its residential and commercial customers. In addition to the AMI meter deployment, BHP is also implementing a Meter Data Management System (MDMS.) The MDMS application will be a core utility business system utilized to collect essential metering information from BHP customers. The MDMS application will help BHP manage customer usage information as we continue to provide reliable and economic service to meet our customers' needs of today and in the future. The MDMS application is scheduled for completion in 2012.

2.3 Plug-in Hybrid Electric Vehicles

Electric vehicles, and their associated battery technology, have been under development for several decades. Today's hybrid electric vehicles, available for purchase by the mass market and part of the rental car fleets, have significantly advanced the likelihood that such cars can be a commercial success and not just an oddity. The hybrid electric vehicles recharge themselves as they are still fueled by gasoline or similar fuel. The next step in the evolution of personal transportation appears to be plug-in hybrid electric vehicles (PHEV) and plug-in electric vehicles, which are dependent on advances in battery technology. This evolutionary step could have significant impacts on the electric utility industry.

PHEVs will require charging, presumably daily. Without grid modernization, the PHEVs could recharge during on-peak periods, thus increasing an electric utility's load and potentially causing the need for new generating capacity. With grid modernization the plug would know not to begin charging until a utility's off-peak hours.

In addition, PHEVs represent what transmission planners call "mobile loads." This means that the car might be charged at home, at the office, at the mall, or at other locations. Such flexibility for the customer will require accommodation through the design or redesign of the transmission and distribution systems which have yet to occur on any utility system in the country including BHP's. No changes to the load forecast or modifications to the transmission and distribution plans are contained in this IRP as would be necessary to accommodate widespread adoption of PHEVs in BHP's service territory.

2.4 Renewable Energy Standards

Wyoming does not currently have a renewable energy standard (RES). South Dakota has adopted a renewable portfolio objective that encourages utilities to generate, or cause to be generated, at least 10% of their retail electricity supply from renewable energy sources by 2015. Absent a specific renewable energy mandate in Wyoming or South Dakota, our current strategy is to prudently incorporate renewable energy into our resource supply, seeking to minimize associated rate increases for our utility customers. Additional information on the RES in South Dakota and Montana are provided below.

2.4.1 South Dakota Renewable Energy Standard[6]

In February 2008, South Dakota enacted legislation (HB 1123) establishing an objective that 10% of all retail electricity sales in the state be obtained from renewable and recycled energy by 2015. In March 2009, this policy was modified by allowing "conserved energy" to meet the objective. This is a voluntary objective, not a mandatory standard, thus there are no penalties or sanctions for retail providers that fail to meet the goal.

Qualifying electricity includes that produced from wind, solar, hydroelectric, biomass (agricultural crops, wastes, and residues; wood and wood wastes; animal and other degradable organic wastes; municipal solid waste; and landfill gas) and geothermal resources, and electricity generated from currently unused waste heat from combustion or another process that does not use an additional combustion process and that is not the result of a system whose primary purpose is the generation of electricity. Hydrogen generated by any of the preceding resources is eligible. In addition to meeting the technology eligibility criteria, electricity must also meet the SDPUC's rules for tracking, recording and verifying renewable energy credits (RECs). Both in-state and out-of-state facilities are eligible to generate qualifying RECs.

Annual reporting to the SDPUC is required.

2.4.2 Montana[7]

Montana's renewable portfolio standard (RPS), enacted in April 2005, requires public utilities and competitive electricity suppliers to obtain a percentage of their retail electricity sales from eligible renewable resources according to the following schedule:

- 5% for compliance years 2008-2009 (1/1/2008 - 12/31/2009)
- 10% for compliance years 2010-2014 (1/1/2010 - 12/31/2014)

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[6]DSIRE: Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/incentives/index.cfm?re=1&ee=1&spv=0&st=0&srp=1&state=SD
[7] DSIRE: Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MT11R&state=MT&CurrentPageID=1&RE=1&EE=1

- 15% for compliance year 2015 (1/1/2015 - 12/31/2015) and for each year thereafter

Eligible renewable resources include wind; solar; geothermal; existing hydroelectric projects (10 megawatts or less); certain new hydroelectric projects (up to 15 megawatts installed at an existing reservoir or on an existing irrigation system that did not have hydroelectric generation as of April 16, 2009); landfill or farm-based methane gas; wastewater-treatment gas; low-emission, non-toxic biomass; and fuel cells where hydrogen is produced with renewable fuels. Facilities must begin operation after January 1, 2005, and must either be located in Montana or located in another state and be delivering electricity into Montana.

Utilities and competitive suppliers can meet the standard by entering into long-term purchase contracts for electricity bundled with renewable-energy credits (RECs), by purchasing the RECs separately, or by a combination of both. The law includes cost caps that limit the additional cost utilities must pay for renewable energy and allows cost recovery from ratepayers for contracts pre-approved by the Montana Public Service Commission (MPSC).

3.0 Assumptions

A wide variety of data assumptions must be made for integrated resource planning (IRP) modeling. Key assumptions described in the following paragraphs were used in the base scenario (scenarios are described in Section 7.1 Analysis). These assumptions include coal price forecasts, natural gas price forecasts, market price forecasts, financial parameters, planning reserves, and emissions costs. The Ventyx 2011 Spring Reference Case for the Western Electricity Coordinating Council (WECC) was used for the long-term natural gas and electric price forecasts. The load and energy forecast is described in its own section of the report that follows this one.

3.1 Coal Price Forecasts

BHP used a coal price forecast that reflects the cost incurred at the time of the IRP modeling for fuel from BHP's coal-fired generating units. These prices as of May 2011 are shown in Table 3-1.

Table 3-1
Coal Price Forecast

Year	All Units (Except Ben French) $/MMBtu	Ben French $/MMBtu*
2011	0.878	1.472
2012	0.985	1.588
2013	1.078	1.689
2014	1.131	1.775
2015	1.224	1.884
2016	1.277	1.954
2017	1.424	2.117
2018	1.477	2.188
2019	1.543	2.272
2020	1.610	2.357
2021	1.690	2.455
2022	1.743	2.528
2023	1.783	2.587
2024	1.876	2.700
2025	1.956	2.801
2026	2.022	2.889
2027	2.076	2.963
2028	2.129	3.039
2029	2.182	3.115
2030	2.209	3.165
*Ben French coal forecast includes transportation costs.		

3.2 Natural Gas Price Forecasts

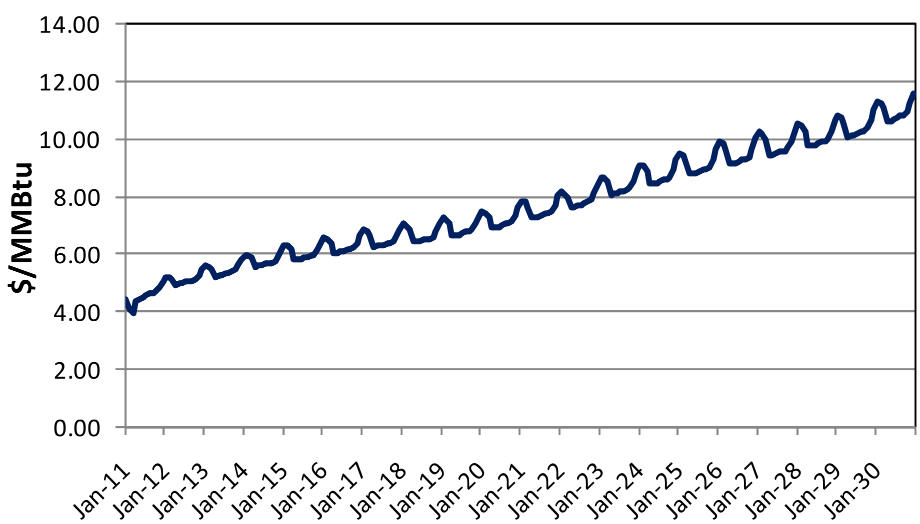
BHP used the natural gas price forecasts from Ventyx's WECC 2011 Spring Reference Case. The Henry Hub values were adjusted by the cost of transportation to reflect the price of natural gas as actually delivered to BHP generating facilities. The Henry Hub natural gas prices are shown monthly in Table 3-2, and Figure 3-1

Table 3-2
Monthly Henry Hub Natural Gas Prices ($/MMBtu)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	4.45	4.06	3.93	4.38	4.46	4.53	4.60	4.63	4.64	4.69	4.85	5.08
2012	5.20	5.18	5.11	4.95	4.97	5.00	5.04	5.07	5.08	5.13	5.26	5.47
2013	5.59	5.56	5.47	5.22	5.25	5.28	5.33	5.36	5.38	5.44	5.59	5.82
2014	5.97	5.95	5.85	5.56	5.58	5.61	5.65	5.68	5.70	5.76	5.92	6.17
2015	6.31	6.27	6.15	5.82	5.82	5.84	5.88	5.91	5.92	5.99	6.15	6.41
2016	6.58	6.54	6.40	6.05	6.06	6.08	6.11	6.15	6.16	6.22	6.39	6.67
2017	6.83	6.78	6.64	6.27	6.28	6.29	6.32	6.35	6.35	6.42	6.59	6.87
2018	7.04	6.99	6.83	6.43	6.43	6.45	6.49	6.53	6.54	6.61	6.80	7.09
2019	7.25	7.20	7.05	6.65	6.66	6.68	6.72	6.76	6.77	6.85	7.04	7.34
2020	7.47	7.43	7.28	6.90	6.91	6.94	6.99	7.03	7.05	7.14	7.33	78.63
2021	7.83	7.79	7.65	7.25	7.27	7.30	7.34	7.39	7.41	7.50	7.70	8.02
2022	8.15	8.12	7.98	7.60	7.62	7.66	7.71	7.77	7.80	7.89	8.09	8.41
2023	8.69	8.65	8.49	8.05	8.08	8.11	8.16	8.21	8.23	8.32	8.55	8.90
2024	9.11	9.06	8.89	8.42	8.44	8.47	8.52	8.57	8.59	8.68	8.91	9.28
2025	9.46	9.41	9.23	8.77	8.79	8.82	8.87	8.92	8.94	9.03	9.26	9.63
2026	9.89	9.83	9.64	9.13	9.15	9.17	9.22	9.27	9.28	9.38	9.62	10.02
2027	10.22	10.16	9.96	9.44	9.45	9.48	9.53	9.58	9.59	9.69	9.93	10.33
2028	10.55	10.49	10.29	9.75	9.76	9.79	9.84	9.89	9.90	10.01	10.26	10.67
2029	10.80	10.74	10.56	10.07	10.08	10.12	10.19	10.25	10.29	10.40	10.65	11.04
2030	11.28	11.24	11.07	10.57	10.60	10.65	10.71	10.78	10.81	10.93	11.19	11.60

Source: Ventyx

Figure 3-1
Henry Hub Natural Gas Prices

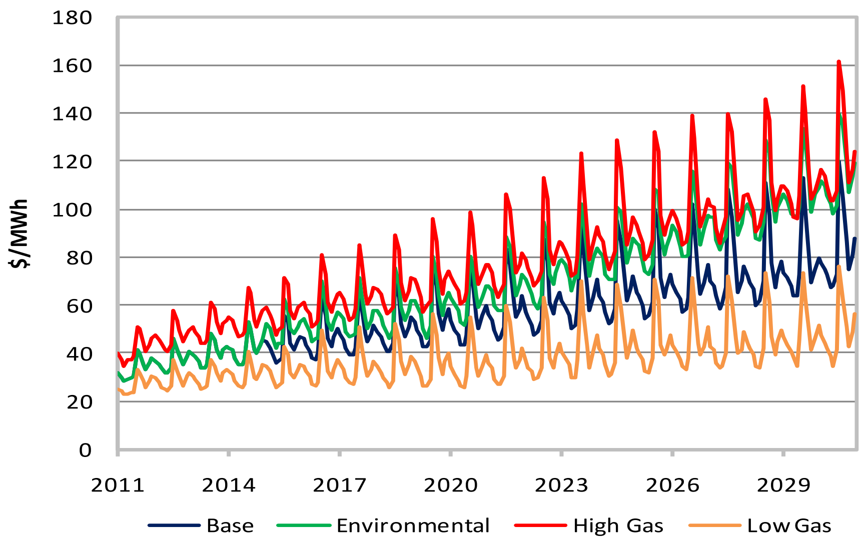


Source: Ventyx

3.3 Market Price Forecasts

Electricity price estimates for the Wyoming region were derived from Ventyx's 2011 Spring Reference Case and are the basis on which BHP's market transactions were priced. The on-peak electricity prices for Wyoming are shown in Figure 3-2. Values are shown for the four scenarios that require the development of correlated natural gas and market prices – base, environmental, low gas and high gas. The description of these scenarios is found in Section 7.1.

Figure 3-2
Reference Case – On-Peak Electricity Prices – Wyoming Region



3.4 Financial Parameters

The financial parameters used in this IRP are summarized in Table 3-3.

Table 3-3
Financial Parameters

Component		Annual Rate (%)
Interest Rate		6.25
Discount Rate		7.41
Income Tax Rate		35
Rate of Escalation		2.5
Capital Structure		
	Equity	52
	Debt	48
Wyoming Property Tax Rate		0.35
Wyoming 20-year Fixed Charge Rate		11.05
Wyoming 30-year Fixed Charge Rate		10.91
Wyoming 50-year Fixed Charge Rate		9.95

A discount rate of 7.41% was used to examine the present value of revenue requirements (PVRR) in this analysis. A levelized fixed charge rate of 9.95% was used for future coal investments, 10.91% for combined cycle investments, 11.05% for solar and wind investments, and 10.91% for peaking investments. Book lives of 50 years were used for coal, 30 years for combined cycle and peaking technology, and 20 years for wind and solar. Tax lives of 20 years were used for coal and combined cycle and peaking technology, 5 year life for solar and wind. A 6.25% short-term debt interest rate was modeled.

3.5 Planning Reserves

Planning reserve margin is defined as the additional capacity required in excess of a utility's peak forecasted demand to ensure resource adequacy for a reliable generation portfolio. Historically around the country, the level of planning reserve margin has generally varied from 15% to 20%. A minimum planning reserve margin of 15% was used in this IRP which is consistent with what other utilities use in the western region and is generally regarded as prudent utility practice.

3.6 Emissions Costs

Federal greenhouse gas emission legislation has failed to gain enough support in Congress to become law and, although lawmakers continue to debate this issue, it does not appear that carbon taxes or a CO_2 cap and trade mechanism will be enacted in the foreseeable future. As such, no carbon taxes are assumed in Ventyx's 2011 Spring Reference Case and thus no carbon taxes are assumed to be put in place during the planning horizon for the base scenario assumptions. For the environmental scenarios, the carbon taxes developed by Ventyx, starting in 2015 and shown in Table 3-4, were assumed.

Table 3-4
Carbon Tax Assumption
(Environmental Scenarios Only)

Year	Carbon Tax ($/ton)
2015	15.74
2016	16.62
2017	17.54
2018	18.52
2019	19.55
2020	20.64
2021	21.79
2022	23.01
2023	24.30
2024	25.68
2025	30.03
2026	34.95
2027	37.75
2028	41.51
2029	46.36
2030	54.06

Source: Ventyx

4.0 Load Forecast

The load forecast for BHP was developed and includes 23 MW of load from the City of Gillette, Wyoming (COG); and the MDU Sheridan Service Territory (MDU Sheridan). BHP is contractually obligated to serve 23 MW of the COG's and the MDU's Sheridan load when Wygen III is not available. The load forecast represents an average annual trended forecast peak and energy growth rate of 1.0% based on seven year historical data. Expected load additions in 2012 through 2016 were also incorporated into the load forecast. The peak demand and energy forecast values are shown in Table 4-1 and Figures 4-1 and 4-2.

Table 4-1
BHP Peak Demand and Energy Forecast 2011-2030

Year	Peak Demand (MW)	Growth in Peak Demand (%)	Annual Energy (MWh)	Growth in Annual Energy (%)	Load Factor (%)
2011*	408		2,283,465		63.9
2012	414	1.47	2,306,302	1.00	63.6
2013	426	2.91	2,389,303	3.60	64.0
2014	430	0.92	2,412,278	0.96	64.0
2015	442	2.72	2,465,252	2.20	64.0
2016	446	0.94	2,504,224	1.58	64.1
2017	450	0.93	2,529,276	1.00	64.2
2018	455	1.14	2,554,576	1.00	64.1
2019	459	0.91	2,580,134	1.00	64.1
2020	464	1.00	2,605,935	1.00	64.1
2021	468	1.00	2,631,995	1.00	64.1
2022	473	1.00	2,658,315	1.00	64.1
2023	478	1.00	2,684,898	1.00	64.1
2024	483	1.00	2,711,747	1.00	64.1
2025	488	1.00	2,738,864	1.00	64.1
2026	492	1.00	2,766,253	1.00	64.1
2027	497	1.00	2,793,915	1.00	64.1
2028	502	1.00	2,821,855	1.00	64.1
2029	507	1.00	2,850,073	1.00	64.1
2030	512	1.00	2,878,574	1.00	64.1
*A new all-time peak of 452 MW was set in 2011.					

The load forecast was adjusted to reflect the achievement of demand-side management programs as well as the energy purchased from Cheyenne Light through the Cheyenne put arrangement for energy from Wygen I. Once the load forecast was complete the forecast Cheyenne put energy from the Cheyenne Light IRP was subtracted from the BHP load forecast.

Figure 4-1

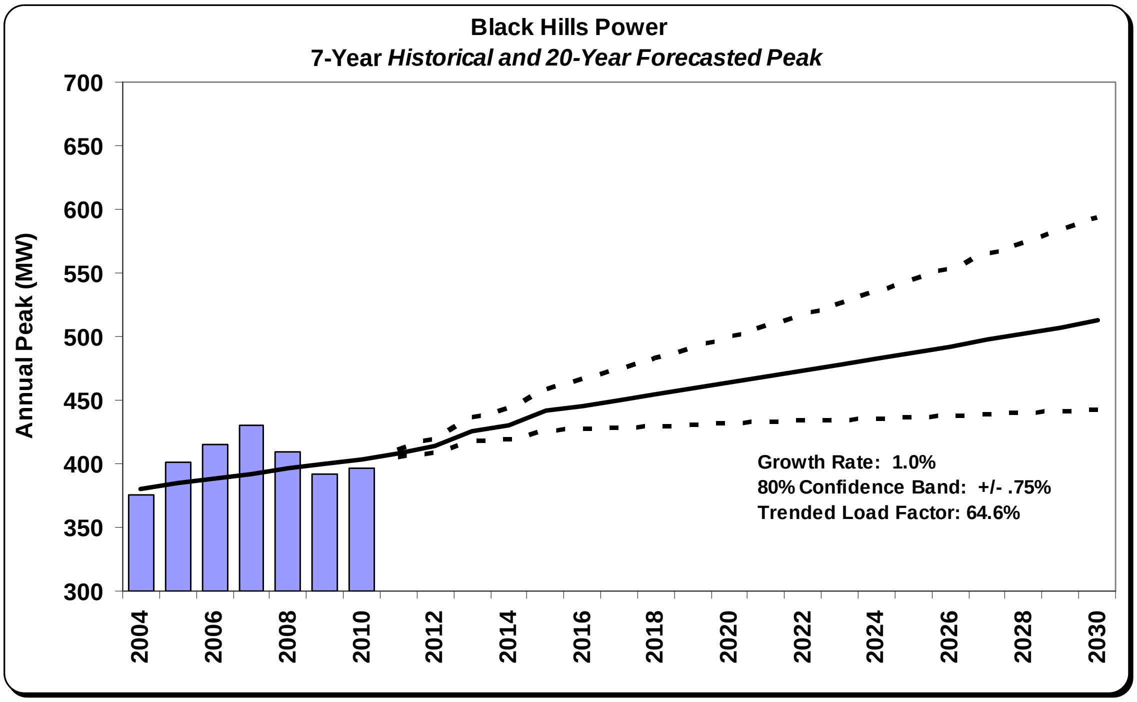


Figure 4-2

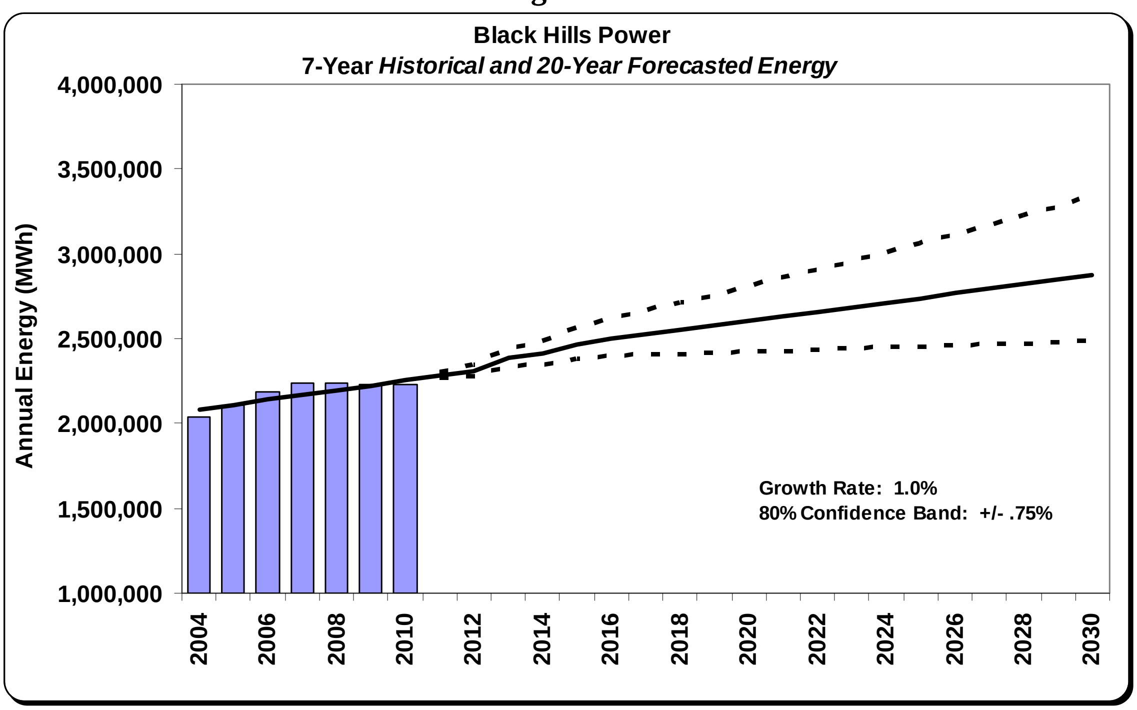


Table 4-2 provides a side-by-side comparison of the values projected for peak demand and annual energy in the 2005 IRP, the 2007 IRP, and in the forecast prepared for this 2011 IRP. The forecast from the 2007 IRP reflects a very strong economy and thus a higher load growth than is seen for the 2011 IRP. This most recent forecast reflects the economic downturn and the resulting effects.

Table 4-2
Load Forecast Comparison

Year	2005 IRP		2007 IRP		2011 IRP	
	Peak Demand	Annual Energy	Peak Demand	Annual Energy	Peak Demand	Annual Energy
2005	400	2,109,780				
2006	405	2,130,870				
2007	410	2,152,190				
2008	415	2,173,700	416	2,234,646		
2009	420	2,197,600	423	2,266,302		
2010	425	2,219,590	429	2,298,835		
2011*	430	2,244,020	436	2,331,971	408	2,283,465
2012	435	2,268,700	441	2,366,184	414	2,306,302
2013	441	2,291,380	448	2,399,829	426	2,389,303
2014	446	2,314,370	456	2,434,563	430	2,412,278
2015	451	2,336,550	461	2,469,844	442	2,465,252
2016	456	2,360,610	468	2,506,235	446	2,504,224
2017			475	2,542,090	450	2,529,276
2018			482	2,579,073	455	2,554,576
2019			489	2,616,638	459	2,580,134
2020			497	2,655,348	464	2,605,935
2021			504	2,693,560	468	2,631,995
2022			512	2,732,935	473	2,658,315
2023			518	2,772,932	478	2,684,898
2024			526	2,814,111	483	2,711,747
2025			534	2,854,832	488	2,738,864
2026			543	2,896,755	492	2,766,253
2027			551	2,939,340	497	2,793,915
2028					502	2,821,855
2029					507	2,850,073
2030					512	2,878,574
*A new all-time peak of 452 MW was set in 2011.						

5.0 Demand-Side Management

BHP's Demand-Side Management (DSM) programs as defined in Docket # EL11-002 were approved by the South Dakota Public Utilities Commission on June 28, 2011. The plan documented the energy efficiency programs that will be implemented in its service territory. In this section of the IRP report, the DSM and energy efficiency programs that are being implemented for BHP and their effects on peak demand and/or energy are presented.

The residential electric portfolio offers customers opportunities to save energy with water heating, refrigerator recycling, heat pumps, and school-based energy efficiency. This portfolio also offers an energy audit program and weatherization teams. The commercial electric portfolio provides both a prescriptive rebate program and a custom rebate program. A brief description of each program is provided below.

5.1 Residential Water Heating

This program offers rebates to BHP residential customers when they replace existing electric water heaters with high-efficiency models or when they install high-efficiency electric tank water heaters in new single-family or specific types of multi-family dwellings. The incentive is $75 per water heater. BHP anticipates that 80 water heaters will be replaced in year 1 of the program, 120 water heaters in year 2 and 160 water heaters in year 3.

5.2 Residential Refrigerator Recycling

The Refrigerator Recycling Program will encourage residential or small business customers to turn in old inefficient refrigerators. The program's goal is to remove inefficient refrigerators from the electric system and dispose of them in an environmentally safe and responsible manner. As part of the program, an incentive will be given to the customer. Initially, a $30 payment will be offered per qualifying unit. A contractor will handle scheduling, transportation and disposal. The contractor will also provide nameplate data on units to assist in impact evaluation. Goals of 150 units for year 1, 225 units for year 2 and 300 units for year 3 have been established.

5.3 Residential Heat Pumps

This program offers rebates to residential customers for installing new, energy efficient heat pumps in new construction or existing homes. Rebates are also paid for the replacement of existing heat pumps and for replacing an electric furnace with a heat pump. Goals for this program are set at 577 units replaced in year 1, 865 units in year 2 and 1,154 units in year 3.

5.4 School-Based Energy Education

This program targets middle school-age children and their households seeking long-term energy savings through enhanced awareness of energy efficiency among students. A specific curriculum has been developed that complements the existing natural science-based education and includes a set of low-cost measures that help ideas and concepts resonate with participating students. Compact fluorescent light bulbs (CFL) will be given to students to install in their homes. A participation goal has been set at 125 students per year.

5.5 Residential Audits

This program will provide on-site audits to customers. The objective of the audit program is to provide recommendations to customers about ways they can reduce the energy consumption in their homes and direct installation of low-cost energy savings measures. Audit recommendations may include suggested behavioral changes and suggestions about repairing, upgrading, or replacing larger, relatively expensive equipment or systems. As a part of the free audit, auditors will install or instruct participating customers on how to install a number of low-cost energy-saving measures. BHP expects to provide audits for 200 customers in each year of this 3-year program.

5.6 Weatherization Team

This program delivers weatherization measures to the low-income community within the Company’s service territory. A variety of weatherization efforts may be undertaken as part of the program offered to low income residential customers including senior citizens and disabled customers. Eligible participants will be identified through Neighborworks, Inc., Western South Dakota Community Action, and Church Response. BHP expects to provide weatherization assistance for 25 customers in each year of this 3-year program.

5.7 Commercial and Industrial Prescriptive and Custom Rebates

This program provides standardized pre-determined rebates to commercial and industrial customers that install, replace or retrofit electric savings measures of pre-qualified performance. These measures include lighting, electric motors, and variable frequency drives. Any energy efficient equipment not covered by the prescriptive component of the rebate program will be eligible for evaluation as a custom rebate. All commercial and industrial customers served by BHP’s standard tariffs are eligible to participate in this program.

The projected program participation and impacts for years 1 through 3 of the Energy Efficiency Solutions Plan are shown on Tables 5-1, 5-2 and 5-3. The plan’s budgets for Year 1 through 3 are shown on Table 5-4.

Table 5-1
DSM Program Portfolio – Year 1

Program Name	Annual Participation Goal	Demand Savings (kW)	Year 1 – Annual Program Impacts (kWh)
Residential Water Heating	80	8	21,207
Residential Refrigerator Recycle	150	30	195,016
Residential Heat Pumps	577	535	1,172,664
School Based EE	125	1	24,921
Residential Audits	200	27	178,157
Weatherization Team	25	N/A	N/A
Residential Total	**1,132**	**601**	**1,591,966**
C/I Prescriptive & Custom Rebate	162	136	1,448,261
Total C/I	**162**	**136**	**1,448,261**
TOTAL	**1,294**	**737**	**3,040,227**

Table 5-2
DSM Program Portfolio – Year 2

Program Name	Annual Participation Goal	Demand Savings (kW)	Year 1 – Annual Program Impacts (kWh)
Residential Water Heating	120	12	31,811
Residential Refrigerator Recycle	225	45	292,524
Residential Heat Pumps	865	802	1,756,665
School Based EE	125	1	24,921
Residential Audits	200	27	178,157
Weatherization Team	25	N/A	N/A
Residential Total	**1,560**	**901**	**2,284,078**
C/I Prescriptive & Custom Rebate	245	205	2,176,632
Total C/I	**245**	**205**	**2,176,632**
TOTAL	**1,805**	**1,107**	**4,460,710**

Table 5-3
Electric Program Portfolio – Year 3

Program Name	**Annual Participation Goal**	**Demand Savings (kW)**	**Year 1 – Annual Program Impacts (kWh)**
Residential Water Heating	160	16	42,415
Residential Refrigerator Recycle	300	59	390,031
Residential Heat Pumps	1,154	1,074	2,351,228
School Based EE	125	1	24,921
Residential Audits	200	27	178,157
Weatherization Team	25	N/A	N/A
Residential Total	**1,964**	**1,177**	**2,986,752**
C/I Prescriptive & Custom Rebate	326	273	2,900,762
Total C/I	**326**	**273**	**2,900,762**
TOTAL	**2,290**	**1,450**	**5,887,514**

Table 5-4
Program Budgets

Program Name	**Year 1**	**Year 2**	**Year 3**
Residential Water Heating	$8,050	$12,075	$16,100
Residential Refrigerator Recycling	$30,700	$46,050	$61,400
Residential Heat Pumps	$125,070	$186,863	$252,038
School Based Energy Education	$5,500	$5,500	$5,500
Residential Audits	$46,800	$46,800	$46,800
Weatherization Team	$10,000	$10,000	$10,000
TOTAL RESIDENTIAL	**$226,120**	**$307,288**	**$391,838**
Commercial/Industrial Prescriptive and Custom Rebate	$267,304	$401,813	$535,465
TOTAL C/I	**$267,304**	**$401,813**	**$535,465**
Cross Program Training, Marketing and Project Management	$100,000	$100,000	$100,000
TOTAL	**$593,424**	**$809,100**	**$1,027,302**

6.0 Supply-Side Resources

6.1 Existing Resources

The resources available to BHP to meet customer obligations include coal-fired units, natural gas-fired units, diesel-fired units, and long-term power purchase agreements (PPA) as shown in Table 6-1. Resources committed under the current PPAs include coal and wind. The PPA with PacifiCorp, referred to as Colstrip, expires in 2023. The wind PPAs at Happy Jack and Silver Sage expire in 2028 and 2029, respectively. The City of Gillette's and MDU's ownership shares in Wygen III are included in BHP's existing resources to account for the City of Gillette's and MDU Sheridan's load being included in BHP's load forecast.

Table 6-1
BHP Existing Resources

Power Plant	Net BHP Capacity (MW)	Fuel Type	State	Start Date
Ben French	22	Coal	SD	1960
Neil Simpson I	16	Coal	WY	1969
Neil Simpson II	80	Coal	WY	1995
Wyodak	62	Coal	WY	1978
Wygen III***	100	Coal	WY	2010
Ben French Diesels 1-5	10	Diesel	SD	1965-1977
Ben French CTs 1-4	100*	Natural Gas	SD	1977-1979
Lange CT	39	Natural Gas	SD	2002
Neil Simpson CT 1	39	Natural Gas	WY	2000
Long-Term PPAs	**Capacity**	**Type**	**Start Date**	**End Date**
PacifiCorp PPA (Colstrip)	50	Firm	1983	2023
Happy Jack	1.5**	Wind	2008	2028
Silver Sage	2**	Wind	2009	2029
TOTAL	**521.5**			

Notes:
*Under terms of the Reserve Capacity Integration Agreement (RCIA) with PacifiCorp, these units are rated at 72 MW total (summer value as of 7/1/2012).
**The accredited capacity for each of the wind PPAs (Happy Jack and Silver Sage) is 10% of the total capacity.
*** Includes City of Gillette and MDU's Wygen III ownership.

6.2 Existing Unit Retirements and Upgrades

Recently adopted and proposed EPA rules are impacting and will continue to impact BHP's generating fleet. Of particular note are the Area Source Rules and utility boiler Maximum Achievable Control Technology (MACT) rules. EPA's final Area Source

Rules went into effect March 21, 2011. These rules affect Ben French 1, Neil Simpson 1 and Osage 1-3. These rules specify limits for mercury emissions and carbon monoxide emissions.

The proposed utility boiler MACT rules are scheduled to be finalized in November 2011. These rules will apply to Neil Simpson II, Wygen I, II, and III. The utility MACT rules set limits on emissions of particulate matter, mercury and hydrogen chloride.

As a result of the promulgation of these rules, BHP undertook studies, through a consultant, of the costs that would be required for compliance with the Area Source Rules as well as the expected standards for making progress on regional haze. Osage units 1-3 are currently in cold storage based on economics. The costs developed for Osage 1-3 indicated that it is not economically viable to retrofit Osage 1-3.

Upgrades for Ben French 1 and Neil Simpson 1 have been modeled as resource options in this IRP. These upgrades include the installation of selective catalytic reduction (SCR), spray dryer absorbers (SDA), and fabric filters. Parameters used to model these upgrades are shown in Table 6-2.

Table 6-2
Existing Unit Upgrades Performance Parameters

Parameter	Neil Simpson 1 Upgrade	Ben French 1 Upgrade
Earliest feasible year of installation	2014	2014
Size, MW (net) - summer	18	22
Full load heat rate, Btu/kWh	14,427	13942
SO_2 Emission Rate, lb/MMBtu	0.00	0.00
NO_x Emission Rate, lb/MMBtu	0.00	0.00
CO_2 Emission Rate, lb/MMBtu	292.6	292.6
Fixed O&M, $/kW-year (2010 $)	54.301	111.44
Variable O&M, $/MWh (2010 $)	6.458	11.57
Forced Outage Rate, %	2.00	2.00
Maintenance Outage Rate, %	3.00	3.00
Capital Cost, $/kW (2010 $)	1,000	1,000

If upgrades are not performed for Neil Simpson 1 and Ben French 1, these units as well as Osage 1-3 will retire in 2014.

6.3 New Conventional Resources

A variety of conventional supply-side resources were examined and considered in preparing this IRP. These include coal, different configurations of natural gas-fired combined cycle, and several types of natural gas-fired simple cycle combustion turbines. In addition, unit upgrades and conversion from combustion turbine to combined cycle configuration were evaluated. A brief description of each type of resource and the cost and other parameters used for modeling are described below.

6.3.1 Coal

New pulverized coal-fired units are assumed to be located in the Gillette, Wyoming area near the Wyodak plant site. Each new unit is rated at 100 MW at the time of the summer system peak. Data used for modeling new coal-fired units are shown in Table 6-3.

Table 6-3
Coal-Fired Power Plant Performance Parameters

Parameter	Value
Earliest feasible year of installation	2017
Size, MW (net) - summer	100
Full load heat rate, Btu/kWh	11,500
SO_2 Emission Rate, lb/MMBtu	0.03
NO_x Emission Rate, lb/MMBtu	0.05
CO_2 Emission Rate, lb/MMBtu	210
Fixed O&M, $/kW-year (2010 $)	26.95
Variable O&M, $/MWh (2010 $)	4.00
Forced Outage Rate, %	2.00
Maintenance Outage Rate, %	2.00
Capital Cost, $/kW (2010 $)	2,627

6.3.2 Combined Cycle Combustion Turbines

In a combustion turbine combined cycle facility, the hot exhaust gases from the combustion pass through a heat recovery steam generator (HRSG). The steam generated by the HRSG is expanded through a steam turbine, which, in turn, drives an additional generator. Combustion turbine combined cycle systems typically burn natural gas and are available in a variety of sizes and configurations. The possible conversion of an existing combustion turbine to a combined cycle configuration was included in the options examined for combined cycle facilities due to BHP owning 2 combustion turbines capable of being converted. Parameters used to model several different configurations of combined cycle facility as a resource are shown in Table 6-4.

6.3.3 Simple Cycle Combustion Turbine

Combustion turbines typically burn natural gas and/or No. 2 fuel oil and are available in a wide variety of sizes and configurations. Combustion turbines are generally used for peaking and reserve purposes because of their relatively low capital costs, higher full load heat rate, and the higher cost of fuel when compared to conventional baseload capacity. Combustion turbines have the added benefit of providing quick-start capability in certain configurations. Certain combustion turbines can regulate for wind as well. Parameters used to model different configurations of combustion turbines as a resource are shown in Table 6-5.

Table 6-4
Combined Cycle Combustion Turbine Power Plant Performance Parameters

Parameter	NS CT Conv to CC – Air/Water	CC Conversion	1 x 1 with Duct Firing	2 x 1	3 x 1
Earliest feasible year of installation	2012	2012	2012	2012	2012
Size, MW (net) - summer	45/55	55	55.7	91.8	137.4
Full load heat rate, Btu/kWh	7,947/7,547	7,947	8,168	7,547	7,562
SO_2 Emission Rate, lb/MMBtu	0.00	0.00	0.00	0.00	0.00
NO_x Emission Rate, lb/MMBtu	0.009	0.009	0.01	0.01	0.01
CO_2 Emission Rate, lb/MMBtu	120	120	117	120	120
Fixed O&M, $/kW-year (2010 $)	13.00	13.00	13.00	13.00	13.00
Variable O&M, $/MWh (2010 $)	2.15	2.15	2.15	2.15	2.15
Forced Outage Rate, %	2.00	2.00	2.00	2.00	2.00
Maintenance Outage Rate, %	2.00	2.00	2.00	2.00	2.00
Capital Cost, $/kW (2010 $)	1,650	1,300	1,427	1,372	1,179

Notes:
1x1 with Duct Firing reflects one combustion turbine and one steam generator
2x1 reflects two combustion turbines feeding one steam generator
3x1 reflects three combustion turbines feeding one steam generator
CC conversion represent the incremental net capacity addition of converting a simple cycle to a combined cycle.

Table 6-5
Simple Cycle Combustion Turbine Power Plant Performance Parameters

Parameter	Small CT	Aeroderivative CT
Earliest feasible year of installation	2012	2012
Size, MW (net) - summer	36.2	90
Full load heat rate, Btu/kWh	9,566	9,000
SO_2 Emission Rate, lb/MMBtu	0.00	0.00
NO_x Emission Rate, lb/MMBtu	0.01	0.03
CO_2 Emission Rate, lb/MMBtu	120	120
Fixed O&M, $/kW-year (2010 $)	10.95	10.95
Variable O&M, $/MWh (2010 $)	3.30	3.30
Forced Outage Rate, %	2.00	3.60
Maintenance Outage Rate, %	2.00	4.10
Capital Cost, $/kW (2010 $)	1,016	1,020

6.3.4 Existing Unit Purchase

BHP may have an option to purchase a portion of the existing Wygen I coal-fired unit, owned by Black Hills Wyoming and located in Gillette, Wyoming in 2014. To evaluate how such a purchase option would fit in BHP's resource mix, the purchase was modeled as shown below in Table 6-6.

Table 6-6
Existing Unit Purchase Performance Parameters

Parameter	Wygen I
Earliest feasible year of installation	2014
Size, MW (net) - summer	30
Full load heat rate, Btu/kWh	11,500
SO_2 Emission Rate, lb/MMBtu	0.03
NO_x Emission Rate, lb/MMBtu	0.05
CO_2 Emission Rate, lb/MMBtu	210
Fixed O&M, $/kW-year (2010 $)	108.61
Variable O&M, $/MWh (2010 $)	7.71
Forced Outage Rate, %	2.00
Maintenance Outage Rate, %	2.00
Capital Cost, $/kW (2014 $)	2,189

6.4 New Renewable Resources

Renewable resources considered in this IRP included solar photovoltaics and wind.

6.4.1 Photovoltaic

A 10 MW solar photovoltaic (PV) generation facility was modeled as one of the renewable options during the IRP process. A PV or solar cell is made of semiconducting material, typically wafer-based crystalline silicon technology, configured such that when sunlight hits the cells, the electrons flow through the material and produce electricity. Usually, about 40 solar cells are combined to form a module. Modules can be characterized as flat plate or concentrator systems. About 10 modules make up a flat plate PV array. Approximately 10-20 arrays would be required to provide enough electricity for a typical household. Parameters used to model PV are shown in Table 6-7.

Table 6-7
PV Performance Parameters

Parameter	Value
Earliest feasible year of installation	2012
Size, MW (net) - summer	10
Full load heat rate, Btu/kWh	N/A
SO_2 Emission Rate, lb/MMBtu	N/A
NO_x Emission Rate, lb/MMBtu	N/A
CO_2 Emission Rate, lb/MMBtu	N/A
Fixed O&M, $/kW-year (2010 $)	12.55
Variable O&M, $/MWh (2010 $)	0.00
Forced Outage Rate, %	0.00
Maintenance Outage Rate, %	0.00
Capital Cost, $/kW (2010 $)	6,100

6.4.2 Wind

Wind turbines use their blades to collect the kinetic energy of the wind. The blades are connected to a drive shaft that turns an electric generator to produce electricity. Wyoming is ranked seventh in terms of wind energy potential among the 50 states – with the possibility to develop 85,000 MW. Parameters used to model wind in this IRP are shown in Table 6-8.

Table 6-8
Wind Performance Parameters

Parameter	Value
Size, MW (net) – summer and winter	30
Fixed O&M, $/kW-year (2010 $)	29.55
Capital Cost, $/kW (2010 $)	1,530

Production Tax Credit of $.022 kWh (2010$) for units on-line before 2020.

7.0 Resource Need Assessment

To meet the future needs of the BHP customers, it is necessary to evaluate the impact of several factors:

- Reduction of available capacity and energy resources due to unit retirements and expiration of PPAs
- Future load growth projections
- A 15% planning reserve margin over the 20-year horizon.

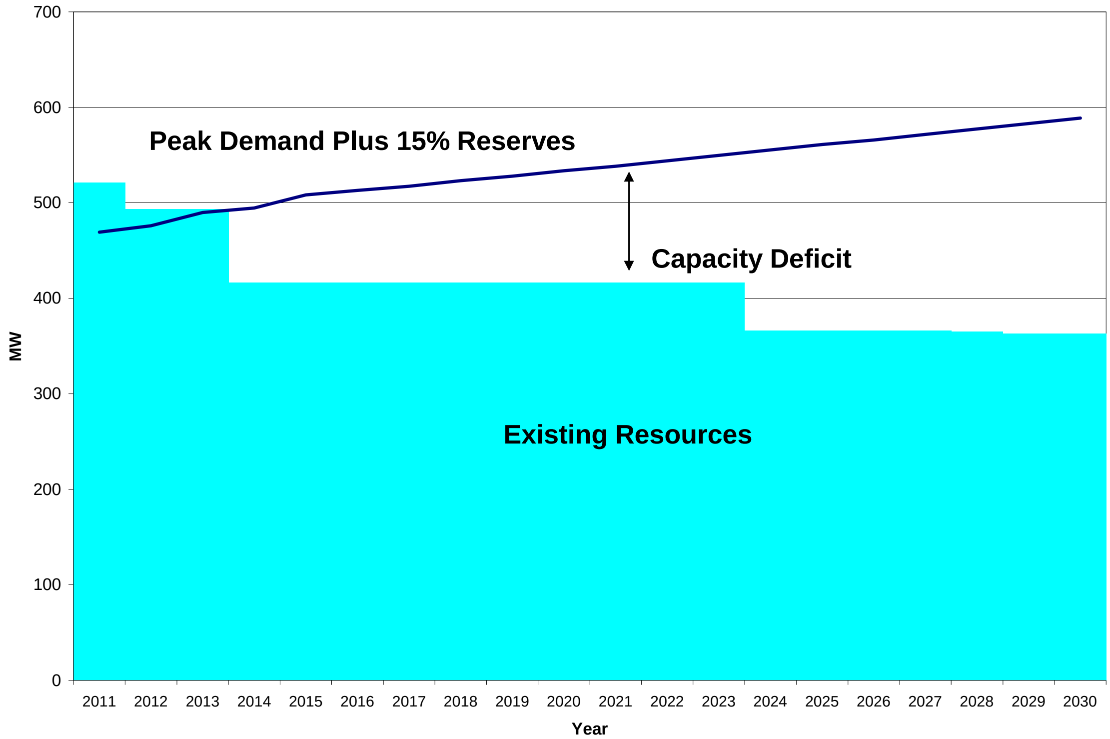
The Area Source Rules have an impact on BHP's Ben French, Neil Simpson 1, and Osage coal-fired generation units. Currently, the Osage units are in cold storage and not counted as an existing resource based on economics, but Ben French and Neil Simpson 1 are in operation and relied upon for system capacity. BHP's future resource need is based on the upgrade or replacement of the Ben French and Neil Simpson 1 units.

In addition, the Reserve Capacity Integration Agreement (RCIA) with PacifiCorp terminates which results in the effective loss of 28 MW of summer capacity. The PPAs with PacifiCorp, Happy Jack, and Silver Sage all terminate over the planning horizon for a loss of 53.5 MW of accredited capacity. As resources retire or existing PPAs terminate, other resources will be required to enable BHP to meets its obligations to serve the electricity needs of its customers.

BHP developed a load and resource balance to compare its annual peak demand with the annual capability of existing resources. The load and resource balance highlights the year in which forecast load exceeds resources and indicates a need for additional generation. The load forecast used as the basis for BHP's load and resource balance includes 23 MW of the City of Gillette's and MDU Sheridan's load and each entity's respective ownership share in Wygen III as an available resource. These loads and resources are included in BHP's load and resource balance because BHP has a contractual obligation to serve these loads when Wygen III is unavailable. The load resource balance also takes into account the planning reserve requirement.

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 as determined from the load and resource balance, is shown on Figure 7-1. 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 reaches approximately 225 MW by the end of the planning horizon.

Figure 7.1
Black Hills Power Load and Resource Summary



A load and resource balance for 2011 - 2015 is shown in Table 7-1.

Table 7.1
Black Hills Power
Load and Resource Balance (2011-2015)

	2011	2012	2013	2014	2015
Peak Demand*	408	414	426	430	442
DSM	0	(1)	(2)	(3)	(3)
Net Peak Demand	408	413	424	427	439
15% Reserve Margin	61	62	64	64	66
Total Demand (including planning reserves)	469	475	488	491	505
Resources					
Ben French 1	22	22	22	0	0
Neil Simpson I	16	16	16	0	0
Neil Simpson II	80	80	80	80	80
Wyodak	62	62	62	62	62
Ben French Diesels	10	10	10	10	10
Ben French CTs 1-4	100	72	72	72	72
Lange CT	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39
Wygen III**	100	100	100	100	100
Total BHP Resources	468	440	440	402	402
Purchases					
Colstrip	50	50	50	50	50
Happy Jack	1.5	1.5	1.5	1.5	1.5
Silver Sage	2	2	2	2	2
Sales					
Sales (MEAN)	30	30	30	30	20
Total Resources	491.5	463.5	463.5	425.5	435.5
Reserve Margin**	5.5%	-2.8%	-5.7%	-15.5%	-15.8%

Notes:
*Forecast Peak load includes 23 MW City of Gillette and MDU Sheridan load
**Includes City of Gillette's and MDU's ownership share
***Reserve margin calculation is in excess of assumed 15% planning reserve margin

7.1 Analysis

The process used to determine the preferred resource portfolio for BHP over the planning horizon began by identifying ten scenarios (also referred to as plans) that the Capacity Expansion module uses to derive optimal resource expansion plans The scenarios include variations in inputs representing the significant sources of portfolio cost variability and risk. These ten scenarios and a brief description of the scenario variables are listed below:

1. Base Scenario
   Used assumptions described in Sections 3.0 through 7.0
   Colstrip contract modeled at 50 MW through December 2023
   Happy Jack expires August 2028
   Silver Sage expires September 2029
   MEAN contract sale through May 2023
   Up to 75 MW firm market purchases in July and August; 6 x 16 product
2. Environmental Scenario
   Same assumptions as Base Scenario
   Included CO_2 emissions price based on Ventyx's 2011 Spring Reference Case – Environmental Case
   Gas and market prices from Ventyx's 2011 Spring Reference Case – Environmental Case
3. High Gas Scenario
   Same assumptions as Base Scenario
   Assumed higher gas and market prices than Base Scenario
4. Low Gas Scenario
   Same assumptions as Base Scenario
   Assumed lower gas and market prices than Base Scenario
5. High Load Scenario
   Same assumptions as Base Scenario
   Assumed a high load forecast
6. Low Load Scenario
   Same assumptions as Base Scenario
   Assumed a low load forecast
7. Step Load Scenario
   Same assumptions as Base Scenario
   Included a 40 MW load increase in 2015
8. Gillette Top Load Scenario
   Same assumptions as Base Scenario
   Included City of Gillette "top load" (load over base 23 MW)
   Assumed Neil Simpson CT 2 purchased by the City of Gillette; BHP serves City's energy requirements
9. Base Scenario with No Firm Market
   Same assumptions as Base Scenario
   Assumed no firm market purchases available in July and August
10. No Combined Cycle Conversion Option
    Same build assumptions as Base Scenario
    No combined cycle conversion option

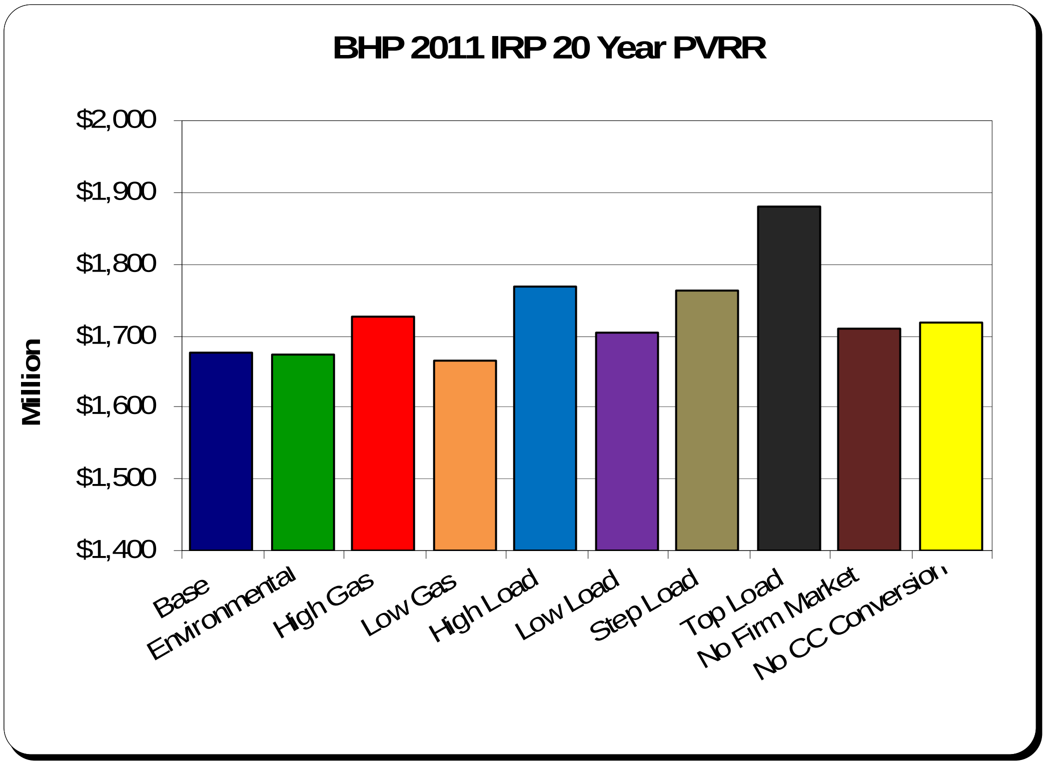
Capacity expansion modeling results (resource portfolios) for these scenarios are shown in Table 7-2.

Table 7-2 - Optimal Expansion Plans **(Source: Ventyx)**

YEAR	Base	Environ mental	High Gas	Low Gas	High Load	Low Load	Step Load	Top Load	Base No Firm Market	No CC Conv Option
2011										
2012	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW
2013	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW	Market 50 MW	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW
2014	CC Conv 55 MW Market 25 MW	CC Conv 55 MW Market 25 MW	CC Conv 55 MW Market 25 MW	CC Conv 55 MW Market 25 MW	CC Conv 55MW Market 50 MW	CC Conv 55 MW	CC Conv 55 MW Market 25 MW	CC Conv 55 MW Market 25 MW	CC Conv 55 MW Simple Cycle 36 MW	Simple Cycle 36 MW Market 50 MW
2015	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW	Market 50 MW		Simple Cycle 36 MW Market 50 MW	Market 50 MW		Market 50 MW
2016	Market 25 MW	Market 25 MW	Market 25 MW	Market 25 MW	Market 50 MW		Market 50 MW	Market 50 MW		Market 50 MW
2017	Market 50 MW	Market 50 MW	Market 50 MW	Market 50 MW	Wygen 1 Purch 30 MW Market 25 MW	Market 25 MW	Market 50 MW	Market 75 MW		Market 50 MW
2018	Market 50 MW	Market 50 MW	Market 50 MW	Market 50 MW	Market 50 MW		Market 50 MW	Market 75 MW		Market 50 MW
2019	Market 50 MW	Market 50 MW	Wygen 1 Purch 30 MW Market 25 MW	Market 50 MW	Market 50 MW	Wygen 1 Purch 30 MW	Wygen 1 Purch 30 MW Market 25 MW	Wygen 1 Purch 30 MW Market 50 MW		Wygen 1 Purch 30 MW Market 25 MW
2020	Market 50 MW	Market 50 MW	Market 25 MW	Market 50 MW	Market 50 MW		Market 25 MW	Market 50 MW		Market 25 MW
2021	Market 50 MW	Market 50 MW	Market 25 MW	Market 50 MW	Simple Cycle 36 MW Market 25 MW		Market 25 MW	Market 50 MW		Market 25 MW
2022	Market 50 MW	Market 50 MW	Market 25 MW	Market 50 MW	Market 50MW		Market 50 MW	Market 75 MW		Market 50 MW
2023	Market 50 MW	Market 50 MW	Market 25 MW	Market 50 MW	Market 50 MW		Market 25 MW	Market 75 MW		Market 25 MW
2024	Coal 100 MW	2 Simple Cycles 36 MW Wind 30 MW Market 25 MW	Coal 100 MW	2 Simple Cycles 36 MW Market 25 MW	Coal 100 MW	Market 25 MW	Coal 100 MW	Coal 100 MW Market 25 MW	Coal 100 MW	Coal 100 MW
2025		Market 25 MW		Market 25 MW		Market 25 MW		Market 25 MW		
2026	Market 25 MW	Market 50 MW		Market 50 MW	Market 25 MW	Market 25 MW		Market 50 MW		
2027	Market 25 MW	Market 50 MW		Market 50 MW	Market 25 MW	Market 25 MW		Market 50 MW		
2028	Market 25 MW	Wind 30 MW Market 50 MW		Market 50 MW	Market 50 MW	Market 25 MW	Market 25 MW	Market 50 MW		Market 25 MW
2029	Market 25 MW	Market 50 MW		Market 50 MW	Market 50 MW	Market 25 MW	Market 25 MW	Market 75 MW		Market 25 MW
2030	Simple Cycle 36 MW	2 Simple Cycles 36 MW Wind 30 MW		2 Simple Cycles 36 MW	2 Simple Cycles 36 MW	Simple Cycle 36 MW	Simple Cycle 36 MW	2 Simple Cycles 36 MW		Simple Cycle 36 MW

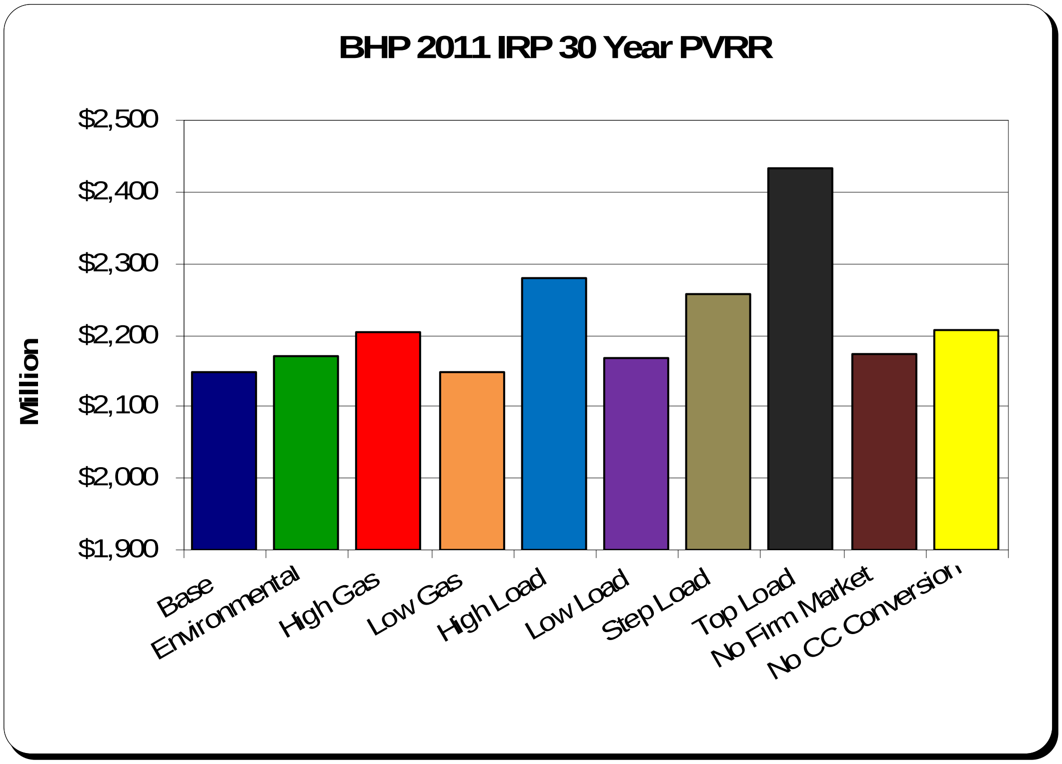
Each of the resource portfolios was then run through a production cost model, and was modeled with the base case scenario assumptions to determine the relative present value of revenue requirements (PVRR). The PVRR for all of the scenarios when run on a deterministic basis are shown on Figure 7-2.

Figure 7-2
Deterministic PVRR for Scenarios



With exception of the environmental and low gas scenario, the base plan has the lowest PVRR. In the environmental scenario, and the low gas scenario, a second simple cycle is added in 2030, the last year of the study. By adding a unit in the last year of the study period the cost associated with the addition are not realized resulting in a lower PVRR and a reduced expected cost based on the stochastic production cost modeling represented in figure 8-1. The concept is known as "end effects" in modeling terms. Figure 7-3 shows the PVRR for all scenarios when run on a 30 year basis to take into account the end effect described above. On a 30 year PVRR the base scenario is the least cost.

Figure 7-3
Deterministic PVRR for Scenarios



8.0 Risk Analysis

Utilities must plan for future customer needs for electricity in an environment of significant uncertainty. Thus, the analysis conducted for this IRP examined uncertainty under a variety of possible future conditions. Analyses conducted to quantify the risk associated with the various scenarios included stochastic analysis, and specific examination of 1) the effects of a step load increase in the BHP demand for electricity, 2) the effects of not having a capacity market available, and 3) the effects of not having a combined cycle as a resource option on the preferred resource portfolio.

8.1 Stochastic Analysis

Ventyx's *Strategic Planning* model uses a structural approach to forecasting prices that captures the uncertainties in demand, fuel prices, supply and costs. Regional forward price curves are generated across multiple scenarios using a stratified Monte Carlo sampling program. Scenarios are driven by a wide range of market drivers that take into account statistical distributions, correlations, and volatilities.

The market uncertainty drivers developed for the specific Wyoming market prices are also used when evaluating the resource mix. During the evaluations, the prices and associated uncertainties provide sufficient information about the market to allow for proper evaluation of alternatives. For example, high gas prices would generally result in high on-peak prices. The following uncertainties were examined in the IRP and resulted in 50 future scenarios for price development and portfolio evaluation:

- Demand
    - Mid-Term Peak by region
    - Mid-Term Energy by region
    - Long-Term Demand (to consider uncertainty in the rate of long-term load growth)
- Fuel Prices
    - Mid-Term Gas Price
    - Mid-Term Oil Price
    - Long-Term Gas, Oil and Coal Price (to consider the price uncertainty in the long-term supply/demand balance)
- Emission Prices
    - Long-Term SO_x, NO_x, and CO_2 Price
- Supply
    - Mid-Term Coal Unit Availability by region
    - Mid-Term Nuclear Unit Availability by region
    - Mid-Term Gas Unit Availability by region
    - Mid-Term Hydro Output by region
- Capital Cost
    - Long-Term Pulverized Coal Capital Cost
    - Long-Term Aero, Combustion Turbine and Combined Cycle Capital Cost
    - Long-Term Wind Capital Cost

The range of values for each of these parameters is developed using either uniform distribution or standard deviations for two related variables that are then correlated. The ranges for some of the variables considered (with 1.0 being the middle) are shown in Table 8-1.

Table 8-1
Ranges for Selected Uncertainty Variables

Variable	Minimum	Maximum
Mid-Term Peak	0.87	1.11
Mid-Term Energy	0.90	1.09
Long-Term Demand	0.85	1.12
Mid-Term Gas	0.70	2.60
Oil Price	0.85	1.18
Long-Term Gas	0.79	1.23
Coal Unit Availability	0.88	1.11
Gas Unit Availability	0.80	1.16
Pulverized Coal Capital Costs	1.00	1.15
Combustion Turbine Capital Costs	1.00	1.10
Combined Cycle Capital Costs	1.00	1.10
Wind Capital Costs	0.90	1.10

Source: Ventyx

8.2 Risk Profiles

During the stochastic analysis, the expansion plans optimized for each case remain the same. The analysis examines the cost of each expansion plan assuming 50 different “futures” and tabulates the PVRR expected for each of those 50 futures. A risk profile for each expansion plan is then constructed using all 50 of those “future” PVRR points.

Cumulative probability distributions, also known as risk profiles, provide the ability to visually assess the risks associated with a decision under uncertainty. These risk profiles are one of the results of the stochastic analysis conducted by Ventyx for BHP. The risk profiles for the scenarios with the exception of the step load scenarios are shown on Figure 8-1. The step load scenario is not included in figure 8-1 because it has a different load then the other scenarios and is not an accurate comparison.

Figure 8-1
Scenarios – Risk Profiles (2011-2030)

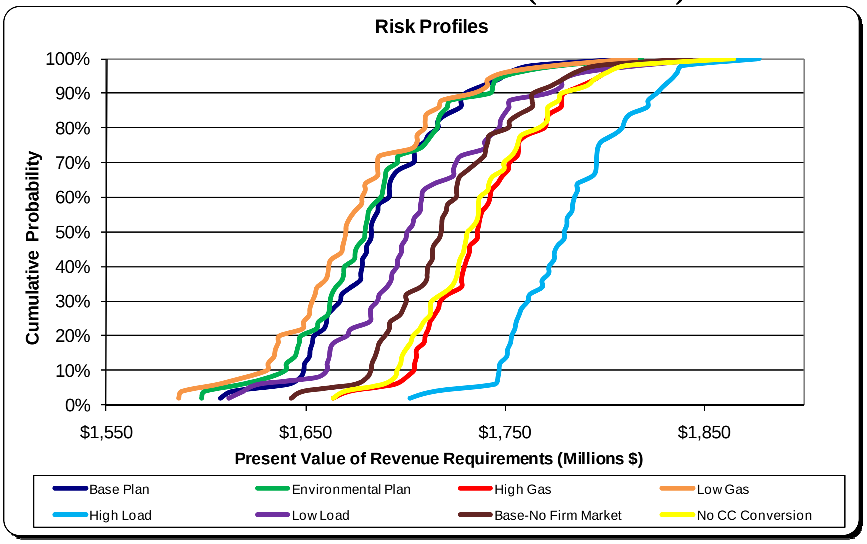
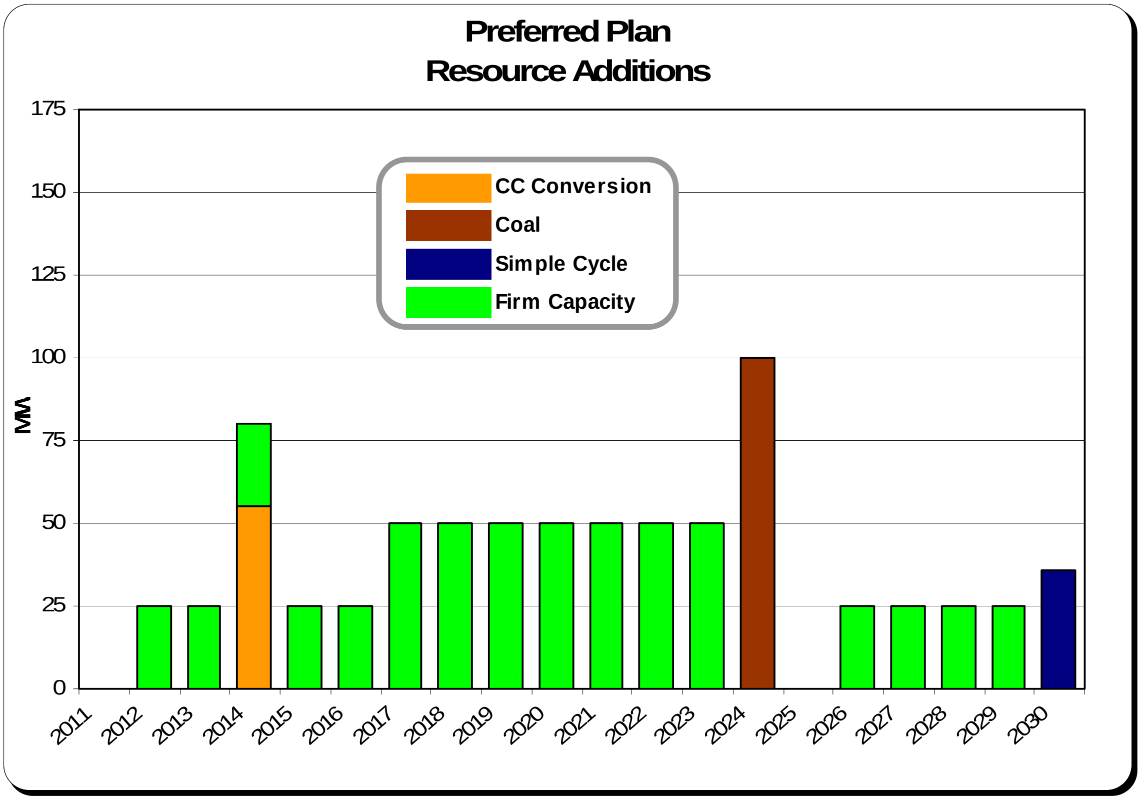


Figure 8-1 shows that with the exception of the low gas and the environmental scenarios, the risk profile for the base plan is to the left and lower than any other case. End effects as discussed in section 7.1 are impacting the risk profiles for the low gas and environmental scenario. The low gas scenario also relies more on market purchases and adds additional market risk not measured in Figure 8-1. Thus the base plan has been selected as the preferred plan. The base plan resource portfolio includes installation of a simple cycle combustion turbine to be converted to a combined cycle unit utilizing an existing simple cycle combustion turbine in 2014 and firm capacity purchases in all of the years 2011-2023. This plan when adjusted for end effects has a low risk profile and expected PVRR value. BHP also benefits from the addition of an efficient combined cycle gas turbine. The resource portfolio for the preferred plan is shown in Figure 8-2. BHP's full load and resource balance for the preferred plan is shown on Table B-1 in Appendix B.

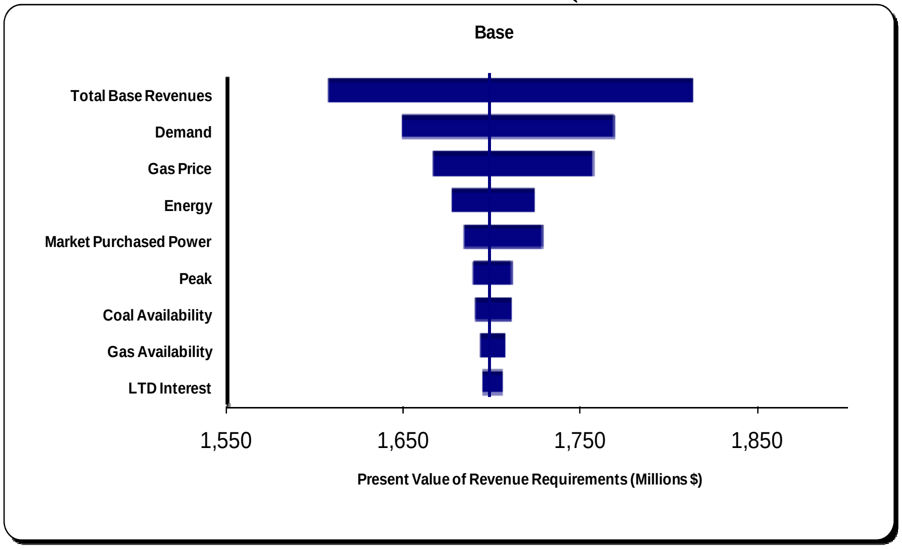
Figure 8-2
Preferred Plan – Resource Additions



8.3 Sensitivity Drivers

The magnitude of the influence that any specific driving factor has in determining the PVRR can be represented in what is called a "tornado chart." The values on this chart are determined through regression analysis and identify the contribution of each variable to the total change in the PVRR. Demand for electricity and natural gas prices are the two primary drivers for the base plan as shown on Figure 8-3. These were also the two primary drivers for all the other scenarios examined in the IRP.

Figure 8-3
Base Plan – Tornado Chart (2011-2030



8.4 Comparison to 2005 and 2007 IRP

In accordance with the Wyoming Public Service Commission's Guidelines Regarding Electric IRPs, for comparison purposes, the load forecast changes between the 2005 IRP, the 2007 IRP and this IRP were shown on Table 4-2. Table 8-2 shows a comparison of the resources in the preferred plan in the 2005 IRP, the resources selected in the 2007 IRP, and the preferred plan resources in the 2011 IRP. Resources selected for the 2005 and 2007 IRP reflect resources required for a combined Cheyenne Light/BHP system.

Table 8-2
Preferred Plan Resource Comparison

Year	Resources from 2005 IRP (2005-2016)	Resources from 2007 IRP (2008-2027)	Resources from 2011 IRP (2011-2030)
2005			
2006			
2007			
2008	Wygen II – 90 MW	Wygen II – 90 MW, Happy Jack – 30 MW	90 MW Wygen II is commercial. Happy Jack is commercial and modeled as an existing PPA
2009	Wygen III – 90 MW, 25 MW of firm market power		Silver Sage Wind is commercial and modeled as an existing 20 MW PPA
2010		Wygen III – 90 MW	Wygen III is commercial and modeled as an existing unit.
2011			
2012		Wind PPA – 25 MW	25 MW firm market power
2013		Wygen IV – 90 MW, Wind PPA – 25 MW	25 MW firm market power
2014			55 MW combined cycle ownership share
2015			25 MW firm market power
2016	LAST YEAR OF STUDY		25 MW firm market power
2017			50 MW firm market power
2018			50 MW firm market power
2019		CT – 67 MW	50 MW firm market power
2020			50 MW firm market power
2021			50 MW firm market power
2022		Wind PPA – 25 MW	50 MW firm market power
2023		Biomass – 11 MW	50 MW firm market power
2024		Wygen V – 90 MW	100 MW coal unit
2025			
2026		Wind PPA – 25 MW, CT – 42 MW	25 MW firm market power
2027		Wind PPA – 25 MW	25 MW firm market power
2028			25 MW firm market power
2029			25 MW firm market power
2030			36 MW combustion turbine

9.0 Conclusions and Recommendations

This IRP was completed to provide a road map to define the system upgrades, modifications, and additions that may be required to ensure reliable and least cost electric service to BHP's customers now and in the future. A full range of resource alternatives, including renewables, were examined with the emphasis on determining the most robust plan that balances risk, reliability, and cost under a variety of possible future scenarios.

BHP's preferred portfolio addresses the generation needs of its customers over the short-term – the next five years - through the implementation of an energy efficiency program, installation of gas-fired combined-cycle combustion turbine technology and firm market purchases. The preferred plan, when adjusted for end effects, is the least cost plan and has low risk associated with future uncertainty. This plan also provides BHP with an efficient combined cycle gas turbine. In addition, the preferred plan meets BHP's objectives to:

- Ensure a reasonable level of price stability for its customers
- Generate and provide reliable and economic electricity service while complying with all environmental standards
- Manage and minimize risk
- Continually evaluate renewables for our energy supply portfolio, being mindful of the impact on customer rates.

9.1 Action Plan

An action plan provides a template for the actions that should be taken over the next several years. BHP should continue to monitor market conditions and regulatory developments so that the items in the action plan can be adapted to address actual conditions as they occur. BHP's plan is as follows:

- In the near term, continue to purchase a firm 6 x 16 product (6 days each week, 16 hours each day) during the summer months to provide for the summer capacity shortfall.
- Purchase or otherwise obtain a simple cycle combustion turbine to be converted to combined cycle operation in 2014.
- Seek opportunities to develop economic renewable resources – particularly wind and solar.
- Actively review development of load growth opportunities in the service territory.
- Monitor transmission developments in the Western U.S.

Appendix A – Software Used in the Analysis

Strategic Planning *powered by MIDAS Gold®* was utilized to measure and analyze the consumer value of competition. Strategic Planning includes multiple modules for an enterprise-wide strategic solution. These modules are:

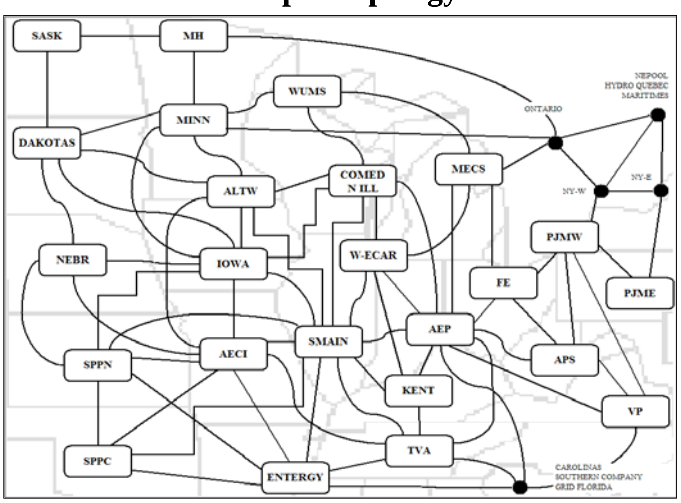
- Markets
- Portfolio
- Financial
- Risk

Strategic Planning is an integrated, fast, multi-scenario zonal market model capable of capturing many aspects of regional electricity market pricing, resource operation, asset and customer value. The markets and portfolio modules are hourly, multi-market, chronologically correct market production modules used to derive market prices, evaluate power contracts, and develop regional or utility-specific resource plans. The financial and risk modules provide full financial results and statements and decision making tools necessary to value customers, portfolios and business unit profitability.

A.1 Markets Module

Generates zonal electric market price forecasts for single and multi-market systems by hour and chronologically correct for 30 years. Prices may be generated for energy only, bid- or ICAP-based bidding processes. Prices generated reflect trading between transaction groups where transaction group may be best defined as an aggregated collection of control areas where congestion is limited and market prices are similar. Trading is limited by transmission paths and constraints quantities.

Figure A-1
Sample Topology



Source: Ventyx

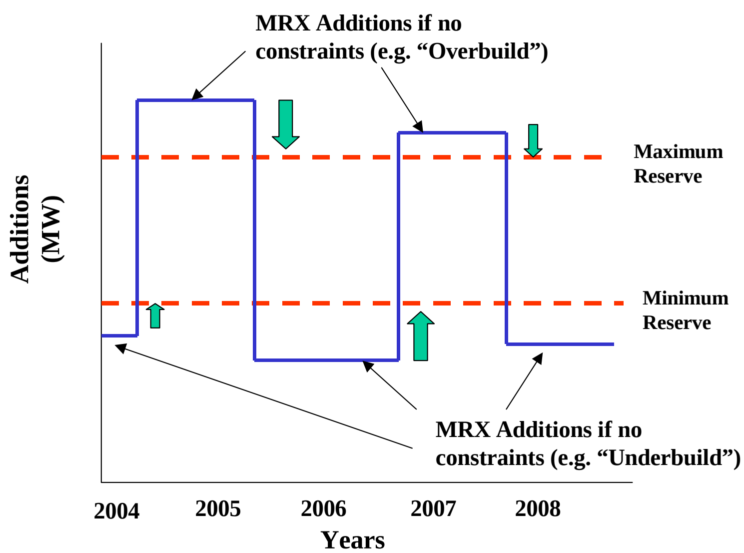
The database is populated with Ventyx Intelligence – Market Ops information. Operational information provided for over 10,000 generating units.

- Load forecasts by zone (where zone may be best defined as utility level) and historical hourly load profiles
- Transmission capabilities
- Coal price forecast by plant with delivery adders from basin
- Gas price forecast from Henry Hub with basis and delivery adders

When running the simulation in markets module, the main process of the simulation is to determine hourly market prices. Plant outages are based on a unit derate and maintenance outages may be specified as a number of weeks per year or scheduled.

The market based resource expansion algorithm builds resources by planning region based on user-defined profitability and/or minimum and maximum reserve margin requirements in determining prices. In addition, strategic retirements are made of non-profitable units based on user-defined parameters.

Figure A-2
MRX Decision Basis



Source: Ventyx

The markets module simulation process performs the following steps to determine price: Hourly loads are summed for all customers within each Transaction Group.

- For each Transaction Group in each hour, all available hydro power is used to meet firm power sales commitments.
- For each Transaction Group and Day Type, the model calculates production cost data for each dispatchable thermal unit and develops a dispatch order.

- The model calculates a probabilistic supply curve for each Transaction Group considering forced and planned outages.
- Depending on the relative sum of marginal energy cost + transmission cost + scarcity cost between regions, the model determines the hourly transactions that would likely occur among Transaction Groups.
- The model records and reports details about the generation, emissions, costs, revenues, etc. associated with these hourly transactions.

A.2 Portfolio Module

Once the price trajectories have been completed in the markets module, the portfolio module may be used to perform utility or region specific portfolio analyses. Simulation times are faster and it allows for more detailed operational characteristics for a utility specific fleet. The generation fleet is dispatched competitively against pre-solved market prices from the markets module or other external sources. Native load may also be used for non-merchant/regulated entities with a requirement to serve.

Operates generation fleet based on unit commitment logic which allows for plant specific parameters of:

- Ramp rates
- Minimum/maximum run times
- Start up costs

The decision to commit a unit may be based on one day, three day, seven day and month criteria. Forced outages may be based on monte-carlo or frequency duration with the capability to perform detailed maintenance scheduling. Resources may be de-committed based on transmission export constraints.

Portfolio module has the capability to operate a generation fleet against single or multiple markets to show interface with other zones. In addition, physical, financial and fuel derivatives with pre-defined or user-defined strike periods, unit contingency, replacement policies, or load following for full requirement contracts are active.

A.3 Capacity Expansion Module

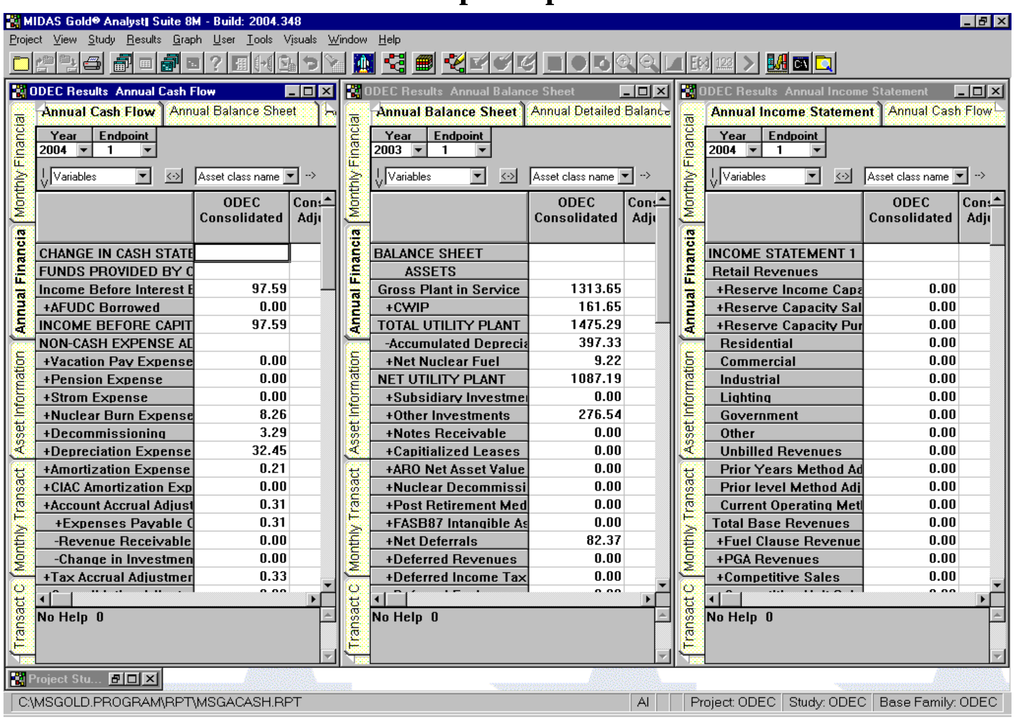
Capacity Expansion automates screening and evaluation of generation capacity expansion, transmission upgrades, strategic retirement, and other resource alternatives. It is a detailed and fast economic optimization model that simultaneously considers resource expansion investments and external market transactions. With Capacity Expansion, the optimal resource expansion strategy is determined based on an objective function subject to a set of constraints. The typical criterion for evaluation is the expected present value of revenue requirements (PVRR) subject to meeting load plus reserves, and various resource planning constraints. It develops long-term resource expansion plans with type, size, location, and timing of capital projects over a 30-year horizon.

Decisions to build generating units or expand transmission capacity, purchase or sell contracts, or retire generating units are made based on the expected market value (revenue) less costs including both variable and fixed cost components. The model is a mixed integer linear program (MILP) in which the objective is minimization of the sum of the discounted costs of supplying customer loads in each area with load obligations. The model can be used to also represent areas that provide energy and capacity from power stations or contracts, but have no load obligations. The model includes all existing and proposed plants and transmission lines in a utility system.

A.4 Financial Module

The financial module allows the user the ability to model other financial aspects regarding costs exterior to the operation of units and other valuable information that is necessary to properly evaluate the economics of a generation fleet. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts.

Figure A-3
Sample Reports



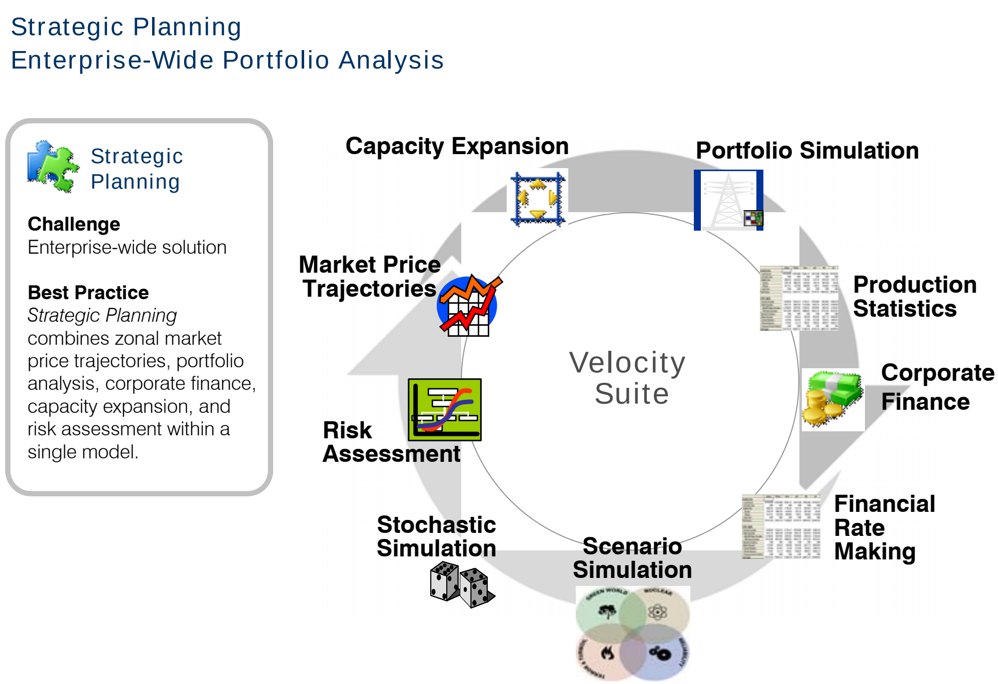
Source: Ventyx

A.5 Risk Module

Risk module provides users the capability to perform stochastic analyses on all other modules and review results numerically and graphically. Stochastics may be performed on both production and financial variables providing flexibility not available in other models.

Strategic Planning has the functionality of developing probabilistic price series by using a four-factor structural approach to forecast prices that captures the uncertainties in regional electric demand, resources and transmission. Using a Latin Hypercube-based stratified sampling program, Strategic Planning generates regional forward price curves across multiple scenarios. Scenarios are driven by variations in a host of market price "drivers" (e.g. demand, fuel price, availability, hydro year, capital expansion cost, transmission availability, market electricity price, reserve margin, emission price, electricity price and/or weather) and takes into account statistical distributions, correlations, and volatilities for three time periods (i.e. Short-Term hourly, Mid-Term monthly, and Long-Term annual) for each transact group. By allowing these uncertainties to vary over a range of possible values a range or distribution of forecasted prices are developed.

Figure A-4
Overview of Process



Source: Ventyx

Appendix B

Table B-1

Black Hills Power
Load and Resource Balance - Preferred Plan

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Demand*	408	414	426	430	442	446	450	455	459	464	468	473	478	483	488	492	497	502	507	512
DSM	0	(1)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	408	413	424	427	439	443	447	452	456	461	465	470	475	480	485	489	494	499	504	509
15% Reserve margin	61	62	64	64	66	66	67	68	68	69	70	71	71	72	73	73	74	75	76	76
Total Demand	469	475	488	491	505	509	514	520	524	530	535	541	546	552	558	562	568	574	580	585
(including planning reserves)																				
Resources																				
Ben French 1	22	22	22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson I	16	16	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs 1-4	100	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Combined Cycle Conversion				55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
New Coal														100	100	100	100	100	100	100
New Combustion Turbine																				36
Total BHP Resources	468	440	440	457	457	457	457	457	457	457	457	457	457	557	557	557	557	557	557	593
Purchases																				
Colstrip	50	50	50	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0
Silver Sage	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0
Capacity	0	25	25	25	25	25	50	50	50	50	50	50	50	0	0	25	25	25	25	0
Sales																				
Sales (MEAN)	30	30	30	30	20	20	20	15	15	12	12	10	10	0	0	0	0	0	0	0
Total Resources	491.5	488.5	488.5	505.5	515.5	515.5	540.5	545.5	545.5	548.5	548.5	550.5	550.5	560.5	560.5	585.5	585.5	585.5	584.0	593.0
Reserve Margin***	5.5%	3.3%	0.2%	3.4%	2.4%	1.4%	5.9%	5.7%	4.6%	4.0%	3.0%	2.1%	0.9%	1.8%	0.6%	4.7%	3.5%	2.3%	0.9%	1.5%

* Peak load includes 23MW COG and MDU Sheridan load
** Included COG's and MDU's ownership share
***Reserve margin calculation is in excess of assumed 15% planning reserve margin.

Appendix C – Carbon Capture and Sequestration Technologies

CO_2 capture processes fall into three general categories: (1) flue gas separation, (2) oxy-fuel combustion in power plants, and (3) pre-combustion separation. Each process has associated economic (cost) and energy (kWh) penalties.

For flue gas separation, the capture process is typically based on chemical absorption where the CO_2 is absorbed in a liquid solvent by formation of a chemically bonded compound. The captured CO_2 is used for various industrial and commercial processes such as the production of urea, foam blowing, carbonated beverages, and dry ice production. Other processes being examined for CO_2 capture from the flue gas include membrane separation, cryogenic fractionation, and adsorption using molecular sieves.

An alternative to flue gas separation is to burn the fossil fuel in pure or enriched oxygen. The flue gas will then contain mostly CO_2 and water vapor. The water vapor can be condensed and the CO_2 can be compressed and piped directly to a storage site. Whereas for flue gas separation, the separation took place after combustion, now the separation occurs in the intake air where oxygen and nitrogen need to be separated. The air separation unit alone can impose a 15% efficiency penalty. Pilot scale studies have indicated that this method of carbon capture can be retrofitted on existing pulverized coal units.

Pre-combustion capture is usually applied in coal gasification combined cycle power plants. The process involves gasifying the coal to produce a synthetic gas. That gas reacts with water to produce CO_2 and hydrogen fuel. The hydrogen fuel is used in the turbine to produce electricity and the CO_2 is captured.

Once the CO_2 is captured, it must be stored in a manner in which it will not be emitted back into the atmosphere. Such storage needs to be: 1) long in duration, preferably hundreds to thousands of years, 2) at minimal cost including transportation to the storage site, 3) with no risk of accident, 4) with minimal environmental impact, and 5) without violating any national or international laws or regulations. Potential storage media include geologic sinks and the deep ocean. Geologic sinks include deep saline formations – subterranean and sub-seabed, depleted oil and gas reservoirs, enhanced oil recovery, and unminable coal seams. Deep ocean storage includes direct injection into the water column at intermediate or deep depths.

Appendix D – Grid Modernization

Grid modernization is expected to facilitate:[8]

- improved electricity flows from power plants to consumers
- consumer interaction with the grid
- improved response to power demand
- reduced incidence of generation resource outages
- more consistent and reliable power quality
- increased reliability and security
- more efficient overall operation

Some of the technologies that will be required in order for the U.S. to realize this vision for grid modernization include:[9]

- AMI meters for advanced measurement
- Integrated two-way communications
- Active customer interface including home area networks with in-home displays
- Meter data management system
- Distribution management system with advanced and ubiquitous sensors
- Distribution geographical information system
- Substation automation including sensors to monitor transformers, relays, digital fault recorders, breakers, and station batteries
- Advanced protection and control schemes
- Advanced grid control devices

The enhancements of the electricity infrastructure in this manner are expected to lead to many benefits including active management and control of electricity generation, transmission, distribution and usage in real time; an optimal balance between supply and demand; reduced numbers of outages; more consistent and reliable power quality; increased reliability and security; and more efficient overall operation, among others.[10]

- **Reduced incidence of outages**. Grids in the future will rely on embedded automation and control devices. Thus energy producers and the operators of the transmission and distribution systems will be able to anticipate, detect, and respond to system problems more quickly than is possible with the technology in place currently.

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[8] "Smart Grid basics," www.smartgrid.gov/basics. "Wotruba, Bill, "Enabling the Smart Grid," *Power Engineering*, May 2010, p. 52.
[9] Joe Miller, Horizon Energy Group, "The Smart Grid – How do we get there?" http://www.smartgridnews.com/artman/publish/Business_Strategy_News/The_Smart_Grid_How_Do_We_Get_There-452.html.
[10] "Smart Grid basics," www.smartgrid.gov/basics. "Wotruba, Bill, "Enabling the Smart Grid," *Power Engineering*, May 2010, p. 52.

- **More consistent and reliable power quality**. When supply and demand are more optimally balanced, operation will be leaner and more efficient which in turn leads to higher levels of customer service.
- **Increased reliability and security**. With the capabilities of the enhanced communication system and associated real-time monitoring, power companies will have increased visibility of the entire generation, transmission, and distribution systems and thus an increased ability to resist both physical threats and cyber attacks. Operations that are networked tend to have increased reliability and reduced expensive downtime. Grid modernization may also increase redundancy, in turn leading to fewer service disruptions.
- **More efficient overall operation**. Grid modernization should reduce bottlenecks and relieve grid congestion. Fewer outages and less congestion should lead to lower costs to customers and, potentially, fewer emissions.

Abbreviations

AMI – Advanced Metering Infrastructure
APPA – American Public Power Association
BHC – Black Hills Corporation
BHP – Black Hills Power
Btu – British Thermal Unit
C/I – Commercial/Industrial
CAIR – Clean Air Interstate Rule
CAMR – Clean Air Mercury Rule
CATR – Clean Air Transport Rule
CC – Combined Cycle
CCB – Coal Combustion By-products
CCR – Coal Combustion Residuals
CCS – Carbon Capture and Sequestration
CFL – Compact fluorescent lamp
CO – Carbon Monoxide
CO_2 – Carbon Dioxide
COG-City of Gillette
CPCN – Certificate of Public Convenience and Necessity
CT – Combustion Turbine
DF – Duct Firing
DSM – Demand-Side Management
EE – Energy Education
EPA – Environmental Protection Agency
FERC – Federal Energy Regulatory Commission
HAPS – Hazardous Air Pollutants
Hg – Mercury
HRSG – Heat Recovery Steam Generator
IGCC – Integrated Gasification Combined Cycle
IRP – Integrated Resource Planning or Integrated Resource Plan
kW – Kilowatt
kWh – Kilowatthour
MACT – Maximum Achievable Control Technology
MAPP – Mid-Continent Area Power Pool
MDMS – Meter Data Management System
MDU – Montana-Dakota Utilities
MEAN – Municipal Energy Agency of Nebraska
MILP – Mixed Integer Linear Programming
MMBtu – Millions of British Thermal Units
MPSC – Montana Public Service Commission
MW - Megawatt
MWh - Megawatthour
NAAQS – National Ambient Air Quality Standards
NO_2 – Nitrogen Dioxide

NO_x – Nitrogen Oxides
O&M – Operating and Maintenance costs
PAC – Power Activated Carbon
PHEV – Plug-in Hybrid Electric Vehicles
PM2.5 – Particulate Matter
PPA – Power Purchase Agreement
PV – Photovoltaics
PVRR – Present Value of Revenue Requirements
RCIA – Reserve Capacity Integration Agreement
REC – Renewable Energy Credit
RES – Renewable Energy Standard
RFP – Request for Proposals
RPS – Renewable Portfolio Standard
SCR – Selective Catalytic Reduction
SDA – Spray Dryer Absorber
SDPUC – South Dakota Public Utilities Commission
SIP – State Implementation Plan
SO_2 – Sulfur Dioxide
TRC – Total Resource Cost test
TWh – Terrawatthour
VOC – Volatile Organic Chemical
WECC – Western Electricity Coordinating Council
WPSC – Wyoming Public Service Commission

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. EL14-___

March 31, 2014

TABLE OF CONTENTS

Exhibits

None

I. INTRODUCTION AND QUALIFICATIONS

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Mark Lux. My business address is 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota, 57701.

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

A. I am currently employed by Black Hills Service Company ("Service Company"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), 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 BHC subsidiaries, including Black Hills Power, Inc. ("Black Hills Power" or the "Company").

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS APPLICATION?

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

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

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 and continue to be involved in the development, engineering, construction and commissioning of the natural gas-fired Cheyenne Prairie Generating Station ("CPGS"), as well as the other natural gas and coal-fired power plants owned by subsidiaries of BHC.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss CPGS, and the construction, operation and maintenance costs for CPGS. In addition, I discuss the other major capital plant investments of Black Hills Power that are included in this rate case. I provide the revised definition of major maintenance that has been adopted by Black Hills Power. I discuss the decommissioning of three of Black Hills Power's coal-fired generation facilities: Neil Simpson I, Osage, and Ben French. I discuss common assets at the Neil Simpson Complex. Lastly, I provide information regarding the Neil Simpson employee work force.

II. <u>CPGS OVERVIEW</u>

Q. PLEASE DESCRIBE CPGS.

A. CPGS is an electric generating plant that will provide a total of 132 MW. CPGS is located on the southeast side of the City of Cheyenne, Wyoming. The power plant includes: a gas-fired combustion turbine generator (37 MW), a combined cycle generator (95 MW), a natural gas supply pipeline, an electric transmission line, ancillary equipment, land and buildings, and a substation. CPGS has adequate and efficient water supply, an abundant natural gas supply, and access to available electric transmission.

Q. HAS THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION ("COMMISSION") HAD AN OPPORTUNITY TO CONSIDER ANY FILINGS RELATED TO CPGS?

A. Yes. Black Hills Power filed an Application for the Phase In of Rates Regarding CPGS Construction Financing Costs with the Commission on December 17, 2012, Docket No. EL12-062. On September 19, 2013, the Commission approved the phase in plan rate for CPGS pursuant to a Decision and Order Granting Joint Motions for Approval of Settlement Agreement and Settlement Stipulation.

Q. DID THE WYOMING PUBLIC SERVICE COMMISSION APPROVE A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR CPGS?

A. Yes. Black Hills Power and its sister utility Cheyenne Light, Fuel and Power Company ("Cheyenne Light") filed a Joint Application for a Certificate of Public Convenience and Necessity ("CPCN") on November 1, 2011, which was approved by the Wyoming Public Service Commission by a Memorandum Decision dated January 8, 2013, in Docket Nos. 20002-81-EA-11 and 20003-113-EA-11 (Record No. 13007) ("CPCN Docket").

Q. PLEASE DESCRIBE YOUR ROLE IN THE CPGS PROJECT.

A. I am responsible for supporting the overall project development and management of the construction of the CPGS power plant. In that role, I oversee the preparation of plans and specifications, oversee the competitive bid process, manage the selection and sourcing of equipment, and manage the construction project. I also supported the process by which the air permit and the industrial siting permit were obtained. In addition, I supported the efforts to obtain the CPCN from the Wyoming Public Service Commission.

Q. WHAT ARE THE MAJOR COMPONENTS OF CPGS?

A. There are five major components of CPGS, as follows:

1. A combined cycle (95 MW) jointly owned by Cheyenne Light (42%) and Black Hills Power (58%) that includes two combustion turbine generators, two heat recovery steam generators and one steam turbine generator.
2. One natural gas-fired combustion turbine generator (37 MW) to be wholly owned by Cheyenne Light.
3. Ancillary equipment, land and buildings, a substation, and other such assets jointly owned by Cheyenne Light (58%) and Black Hills Power (42%).
4. A 10.5 mile long, high pressure natural gas supply pipeline owned by Cheyenne Light.
5. An electric transmission line, owned by Cheyenne Light, interconnecting the combined cycle and the combustion turbine generator to Cheyenne Light's existing 115 kV transmission system.

Q. PLEASE DESCRIBE THE CPGS GAS PIPELINE.

A. Black Hills Power and Cheyenne Light are constructing a 12 inch diameter high pressure natural gas transmission pipeline ("CPGS Pipeline"). It is approximately ten and one-half miles in length. It will connect CPGS to the Southern Star Central Gas Pipeline ("Southern Star"). It originates at an interconnection with

Southern Star at a point just north of the Wyoming – Colorado State line and east of Highway 85.

Black Hills Power will have 42% of the CPGS Pipeline capacity. Cheyenne Light will have the remaining 58% of the CPGS Pipeline capacity. Cheyenne Light's natural gas utility will own, operate and maintain the CPGS Pipeline. The testimony of Kent Kopetzky provides further information regarding the pipeline transportation capacity and natural gas supply for CPGS. The testimony of Chris Kilpatrick addresses allocation of the costs for the CPGS Pipeline.

Q. PLEASE DESCRIBE HOW CPGS WILL INTERCONNECT WITH CHEYENNE LIGHT'S 115 kV TRANSMISSION SYSTEM.

A. CPGS will interconnect to Cheyenne Light's 115 kV transmission system at a new 115 kV substation located at the project site. The 115 kV substation is being constructed to initially accommodate a double circuit 115 kV transmission line and two 115/13.8 kV GSU transformers.

III. <u>CPGS COST OF CONSTRUCTION</u>

Q. IS THERE A PRICE CAP FOR THE CONSTRUCTION COSTS FOR CPGS?

A. Pursuant to a settlement between Black Hills Power, Cheyenne Light, and the Wyoming Office of Consumer Advocate in the CPCN Docket, a price cap of $222 million dollars was established for CPGS.

Q. DO YOU ANTICIPATE THAT THE ACTUAL CONSTRUCTION COST OF CPGS WILL BE AT OR BELOW THE PRICE CAP OF $222 MILLION?

A. Yes.

Q. PLEASE DISCUSS THE COST OF THE CPGS PIPELINE.

A. Cheyenne Light has contracted with a third party to build the CPGS Pipeline and the Southern Star interconnection, at a cost of approximately $9 million. For information regarding allocation of costs, please see the testimony of Christopher Kilpatrick.

Q. HOW CONFIDENT ARE YOU IN THE ABOVE CONSTRUCTION COST ESTIMATES?

A. I am very confident in these estimates because nearly all of the contracts entered into for the construction of the CPGS plant are fixed price contracts. In addition, I am confident in the anticipated costs because of our experience in constructing other power plants owned by Black Hills Power and other subsidiaries of BHC.

Q. ARE THERE ANY SPARE PARTS FOR CPGS?

A. Yes. There is $1,029,000 in spare parts allocated to Black Hills Power and included in the Revenue Requirement Model. See Schedule F-4 of Section 4 for a complete listing.

Q. WHY DOES THE COMPANY NEED AN INVENTORY OF SPARE PARTS FOR CPGS?

A. The spare parts are based on the critical need of CPGS to have these items on hand, in accordance with prudent utility practice, thereby reducing the amount of lost production time. The amount of spare parts set forth in Schedule F-4 of Section 4 is appropriate, based on my experience and falls within the industry standard of two percent of the total investment capital.

Q. WHO HAS MANAGED THE CONSTRUCTION OF THE CPGS POWER PLANT?

A. Black Hills Power and Cheyenne Light have used an owners' self-build approach regarding the management of the construction of CPGS, rather than contracting with a third party to engineer, procure, and construct the facility.

Q. DESCRIBE THE PROCESS BY WHICH THE COMPANY SECURED CONTRACTS FOR THE CONSTRUCTION OF CPGS.

A. At the time the Company was preparing for the construction of CPGS, the United States economy was just starting to recover from a recession. As a result, the Company believed that it was in a position to favorably negotiate the price of the significant components. The Company determined that it was important to secure fixed priced contracts for all direct costs that were based on competitive bid pricing. To obtain the benefits of competitive bidding in light of the recession, the Company began by securing fixed price contracts from some key vendors and subcontractors. Locking in these key contracts at this early stage allowed the

Company to insure that the construction process could proceed in a timely manner with secured but reasonably priced resources. After these key contracts were secured, the remainder of the project was secured through competitively bid fixed price contracts.

In summary, the CPGS project strategy involved securing key contracts early to establish a reliable schedule and reduce price risk, and then subsequently securing competitively bid fixed priced contracts for the remainder of the project.

Q. EXPLAIN HOW THE COMPETITIVE BID PROCESS WORKED.

A. The Company hired Kuljian as the engineer of record for CPGS. Kuljian prepared the specifications for the plant. After the Company reviewed and approved these specifications, Kuljian prepared requests for proposals that were submitted to various potential vendors. Kuljian reviewed the bid proposals submitted by the vendors and made recommendations to the Company. The Company also reviewed the bid proposals and ultimately accepted the successful bid proposals.

Q. WERE ALL SUCCESSFUL BIDDERS REQUIRED TO PROVIDE SECURITY FOR THEIR PERFORMANCE?

A. Yes, all successful bidders for major construction and major process equipment were required to provide security for their performance.

IV. STATUS OF CPGS CONSTRUCTION

Q. PLEASE GENERALLY DESCRIBE THE CURRENT STATUS AND EXPECTED COMPLETION OF THE CONSTRUCTION OF CPGS.

A. At this time, construction is on schedule. Black Hills Power anticipates that construction of CPGS will be complete and the plant will be operational by October 1, 2014. All of the major project equipment has been delivered to the CPGS site. In general terms, as of mid-March, 2014, the construction phase was approximately 64% complete and the total project (which includes engineering, procurement, construction and commissioning) was considered to be approximately 85% complete.

V. OPERATIONS AND MAINTENANCE COSTS FOR CPGS.

Q. WHAT ARE THE ESTIMATED ANNUAL OPERATING AND MAINTENANCE COSTS FOR CPGS AND HOW DID YOU ARRIVE AT THIS FORECAST?

A. Black Hills Power estimates its total annual operation and maintenance costs for CPGS to be approximately $2.78 million. The forecast was done at the Federal Energy Regulatory Commission ("FERC") account level and is included as Schedule H-15 of Section 4. This forecast utilizes the historical and budget information for an existing combined cycle and similar projects that are also operated by Service Company, with appropriate adjustments for labor, various consumables, and other costs.

Q. WHAT EXPENSES ARE INCLUDED IN THE OPERATIONS AND MAINTENANCE COST FIGURE?

A. The estimated total annual operation and maintenance costs for CPGS includes primarily: i) the cost of labor to operate the plant; ii) the consumables; and iii) maintenance and repairs. The estimate does not include the cost of the fuel for the CPGS plant.

Q. HOW DID THE COMPANY ESTIMATE THE COST OF LABOR TO OPERATE THE PLANT?

A. The estimated cost of labor to operate the plant is a function of how much CPGS will run. It is expected that CPGS will need to be staffed twenty four hours per day, and seven days per week. Accordingly, CPGS will have eighteen full time equivalent employees.

VI. <u>CPGS PLANT OPERATIONS</u>

Q. WHO WILL OPERATE CPGS?

A. Service Company will be responsible for the operation of CPGS.

Q. WHAT ARE THE ADVANTAGES OF THE COMBINED CYCLE UNIT THAT IS PART OF CPGS?

A. A combined cycle unit, which is an intermediate resource, provides a number of advantages and benefits to Black Hills Power and Cheyenne Light. Specifically, i) it operates at a lower heat rate than a combustion turbine generator; ii) it lowers environmental emissions; iii) it reduces utility exposure to future environmental mandates or taxes; iv) it reduces reliance on the energy markets; v) it creates diversification of the generation resource mix for both Black Hills Power and Cheyenne Light; and vi) it can provide economical system and wind regulation.

Q. PLEASE EXPLAIN THE AIR QUALITY CONTROLS EMPLOYED AT CPGS.

A. CPGS employs state of the art air quality control technology. Once CPGS commences operation, it will likely be the cleanest operating power plant in Wyoming and one of the cleanest operating natural gas-fired plants in the nation. To the best of my knowledge, this is the first power project where this vendor of the natural gas turbines guaranteed the CO_2 emission performance of the combustion turbines.

VII. OTHER CAPITAL PLANT INVESTMENTS

Q. HAS BLACK HILLS POWER MADE CAPITAL INVESTMENTS OTHER THAN CPGS?

A. Yes. Black Hills Power has made a number of capital investments in its existing generation facilities which are listed in Schedule D-10 of Section 4 and are expected to be in service on or before September 30, 2014.

Q. PLEASE DESCRIBE THE MAJOR PLANT CAPITAL INVESTMENTS BLACK HILLS POWER IS INCLUDING IN THIS RATE CASE.

A. There are several categories of major capital investments to existing generation that are included in this rate case. The categories, associated approximate costs, and more specific examples are as follows:

1. $0.3 million allocated to Safety and Security Projects. Within this category are projects including the purchase of a man lift crane to ensure that elevated security areas at the Neil Simpson Complex have access for operations and maintenance to perform work, and alteration of the main entrance to the Neil Simpson Complex to provide a means to safely and securely manage the access point to the property.
2. $2.1 million allocated to Control Systems projects. The majority of the projects that fall within this category relate to efforts that were undertaken to address obsolete controls for production equipment.
3. $6 million allocated to Environmental Projects. Examples of projects contained within this category are installation of an enclosure around the Wygen III reagent preparation area to allow for increased personal safety and equipment reliability, end of life replacement of a catalyst removal system for Wygen III, addition of a hydrated lime injection system for early removal of SO2 upon firing Wygen III, installation of a new air quality control system to meet the Environmental Protection Agency ("EPA") MATS rules at Wyodak, and conversion of the Neil Simpson II startup fuel from fuel oil to natural gas to improve emission performance.
4. $3.5 million allocated to Equipment Reliability projects that individually exceed $100,000 in costs. Included in this category are projects involving replacement of boiler water wall tubes due to fireside corrosion inherent with low NO_x burner characteristics, the addition of a portable conveyor for

the coal handling system to provide a redundant or back-up should the existing system fail, and replacement of the furnace water wall panel on Wygen III to address fire side corrosion.

5. $1.1 million allocated to Regulation Requirements. Examples of projects included in this category are installation of a buffer around the Wygen II and III storm water pond to satisfy a state mandate for facilities located near wetlands, extending the concrete apron around the areas of ash haulers, and installation of a dust control containment system to satisfy a new OSHA dust standard.

6. $0.4 million allocated to Facilities. Included within this category are HVAC upgrades at the Neil Simpson Complex and procurement of a large forklift for inventory maintenance support at the Neil Simpson Complex.

Q. PLEASE BRIEFLY DESCRIBE YOUR INVOLVEMENT WITH THE AFOREMENTIONED PROJECTS.

A. My responsibility includes project approvals to ensure projects are prudent and cost effective.

Q. WERE THESE CAPITAL INVESTMENTS PRUDENTLY UNDERTAKEN?

A. Yes. The capital investments are necessary to continue to provide safe and reliable service to Black Hills Power's customers.

VIII. DEFINITION OF MAJOR MAINTENANCE

Q. PLEASE DEFINE MAJOR MAINTENANCE.

A. Any time Black Hills Power opens its turbine generators the associated work is considered major maintenance.

Q. PLEASE DESCRIBE HOW MAJOR MAINTENANCE HAS HISTORICALLY BEEN ADDRESSED BY BLACK HILLS POWER.

A. Historically, Black Hills Power has scheduled major maintenance work for its coal-fired generation units on an eight year cycle.

Q. DOES BLACK HILLS POWER PLAN TO ALTER ITS MAJOR MAINTENANCE CYCLE FREQUENCY?

A. Yes. Black Hills Power plans to perform major maintenance work every four years.

Q. WILL THE SAME MAJOR MAINTENANCE CYCLE FREQUENCY APPLY TO THE CPGS GENERATION UNITS?

A. No. Black Hills Power's coal-fired generation units are run consistently and therefore a major maintenance schedule is easily determined. Conversely, the combined cycle unit located at CPGS is an intermediate generation unit. Because run time for the combined cycle is undetermined, major maintenance will be scheduled to occur when the unit has exceeded the recommended amount of run time hours.

Q. WILL THE CHANGE IN THE MAJOR MAINTENANCE SCHEDULE RESULT IN INCREASED COSTS TO CUSTOMERS?

A. No, the change in schedule for major maintenance activities will not increase costs to customers. The allocation of major maintenance costs is discussed in more detail in the testimony of Chris Kilpatrick.

IX. <u>DECOMMISSIONING</u>

Q. PLEASE GENERALLY DESCRIBE BLACK HILLS POWER'S NEIL SIMPSON I, OSAGE, AND BEN FRENCH COAL-FIRED GENERATION FACILITIES.

A. Neil Simpson I (21.8 MW) is located in Campbell County, Wyoming and has been in service since 1969. Osage (three boilers with a total of 34.5 MW) is located in Weston County, Wyoming. The last of the three boilers located at this facility was placed in service in 1952. Ben French (25 MW) is located in Pennington County, South Dakota, and has been in service since 1960. Each of these three facilities includes a coal-fired boiler with a capacity of 25 MW or less.

Q. HAS THE EPA ADOPTED REGULATIONS THAT IMPACT NEIL SIMPSON I, OSAGE, AND BEN FRENCH?

A. Yes, the EPA issued the National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers ("Area Source Rules"). The 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.

Q. WHAT ARE THE IMPLICATIONS OF THE AREA SOURCE RULES?

A. 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. The deadline for compliance with the Area Source Rules is March 21, 2014. In order for Black Hills Power to comply with the Area Source rules, it is required to either: (1) retrofit these three affected facilities with expensive new environmental controls; or (2) retire Neil Simpson I, Osage, and Ben French.

Q. HAS BLACK HILLS POWER MADE A DETERMINATION REGARDING COMPLIANCE WITH THE AREA SOURCE RULES?

A. Yes. As a result of the costs involved to retrofit these units, the need for life extension upgrades if the units were to continue to operate, and the likelihood of additional future EPA regulations that would affect 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 no later than March 21, 2014.

Q. PLEASE DESCRIBE YOUR ROLE IN THE DECOMMISSIONING OF NEIL SIMPSON I, OSAGE, AND BEN FRENCH.

A. I am responsible for supporting the overall project development and management of the decommissioning of these facilities. In this role, I oversee preparations of plans and specifications, the competitive bid process, selection of the decommissioning contractor, and management of the decommissioning process.

Q. HOW HAS BLACK HILLS POWER PREPARED FOR THE DECOMMISSIONING OF THESE FACILITIES?

A. Black Hills Power retained Environmental Resources Management ("ERM") to conduct Environmental Site Assessments ("ESA") at all three facilities. Based upon the data obtained during the site visits, review of publicly available information sources, and interviews with persons familiar with the sites, ERM identified the environmental conditions that need to be addressed through abatement or removal.

The Company also retained Black & Veatch, a global engineering, consulting, and construction company, to consult on preparation of the Request for Proposal ("RFP") for the decommissioning work and the overall decommissioning process. An RFP was issued in March of 2013. In response, vendors submitted proposals through a competitive bidding process. Black Hills Power subsequently selected Independence Excavating, LLC ("IX") to decommission these facilities, as it had submitted the lowest cost proposal that met the technical specification of the RFP.

Q. WHAT ARE THE FORECASTED COSTS ASSOCIATED WITH DECOMMISSIONING THESE FACILITIES?

A. The following table provides a summary of estimated decommissioning costs by plant:

Generation Unit	**Demolition & Abatement Bid**	**Salvage Value Credit**	**RFP Lump Sum Bid**	**Environmental Assessments / Other Costs**	**Total Decommissioning Budget**
Osage	3,296,300	(573,000)	2,723,300	1,228,436	$ 3,951,736
Neil Simpson I	2,315,000	(420,000)	1,895,000	1,080,413	$ 2,975,413
Ben French	2,709,000	(420,000)	2,289,000	1,670,606	$ 3,959,606

Q. PLEASE EXPLAIN WHAT IS INCLUDED IN THE COLUMN ENTITLED ENVIRONMENTAL ASSESSMENTS / OTHER COSTS.

A. The Environmental Assessments / Other Costs column above includes the cost of performing the individual ESA at each of the three facilities. This section includes the cost of retaining the professionals to conduct the assessments as well as costs associated with well closure, waste disposal, asbestos abatement and bonding. Two ESAs were conducted to research and analyze any potential liabilities from an environmental impact perspective. Additionally, this category of costs includes site management during decommissioning, and indirect costs such as insurance and permits required throughout the decommissioning progress.

Q. HOW CONFIDENT IS BLACK HILLS POWER IN THE FORECASTED DECOMMISSIONING COSTS?

A. Black Hills Power is very confident in these costs because the decommissioning contract is a fixed price contract.

Q. PLEASE DISCUSS THE DECOMMISSIONING SCHEDULE.

A. Decommissioning efforts at the Osage facility are scheduled to begin in August of 2014, with a target date for completion of April of 2015. Decommissioning efforts at the Neil Simpson I facility are scheduled to begin in November of 2014 and estimated to be completed in June of 2015. Finally, decommissioning efforts at the Ben French facility are scheduled to begin in January of 2015 and estimated to conclude in September of 2015.

X. THE NEIL SIMPSON COMPLEX AND ASSOCIATED COMMON ASSETS

Q. WHAT FACILITIES ARE LOCATED AT THE NEIL SIMPSON COMPLEX?

A. The following generation facilities are located in Gillette, Wyoming at the Neil Simpson Complex: Wygen III, Neil Simpson II, Wyodak, and the Neil Simpson CT.

Q. WHAT PERCENTAGE OF OWNERSHIP DOES BLACK HILLS POWER HAVE IN EACH OF THESE FACILITIES?

A. Black Hills Power owns 52% of Wygen III, 100% of Neil Simpson II, 20% of Wyodak, and 100% of the Neil Simpson CT.

Q. PLEASE DESCRIBE THE COAL STOCKPILE ITEM AT THE NEIL SIMPSON COMPLEX ("NEIL SIMPSON COMPLEX") LISTED ON SCHEDULE F-1, LINE 31.

A. The coal plants at the Neil Simpson Complex are directly adjacent to the Wyodak Mine. The coal is crushed in a secondary crusher building and then this mine-mouth coal is fed through a single conveyor belt system. This system is maintained and operates very reliably. However, the reliance on a single non-redundant source of coal to these facilities is a risk to the plant operations. This risk has been evaluated and based on the potential for interruption of the supply of coal to all the coal plants at the Neil Simpson Complex, the single secondary crusher building and conveyor belt system is identified as a significant risk. Although the Company has limited coal storage available, an event causing major damage to the coal supply system could prevent the operation of all the power plants at the Neil Simpson Complex and pose risk to the ability to adequately supply power to customers. Therefore, the decision was made to stockpile coal at the Neil Simpson Complex.

Q. IS THE NEIL SIMPSON COMPLEX COAL STOCKPILE ADJUSTMENT PRUDENT AND NECESSARY?

A. Yes, the back-up coal supply system project and adding a coal stock pile to inventory is prudent to ensure reliable power supply to customers.

Q. HAS BLACK HILLS POWER MADE OTHER INVESTMENTS IN THE COMMON ASSETS AT THE NEIL SIMPSON COMPLEX?

A. Yes. The post test year Neil Simpson Complex common asset additions are set forth on Schedule D-10, lines 26-40, 44. The Neil Simpson Complex Shared Facilities adjustment has been updated to reflect these additions on Schedule H-10.

XI. LABOR FORCE

Q. ONCE OPERATIONS ARE COMPLETELY SUSPENDED AT NEIL SIMPSON I, WILL BLACK HILLS POWER REALIZE A DECREASE IN LABOR FORCE?

A. No. There are currently eight full time equivalent employees allocated to Neil Simpson I. These employees have been retained by Black Hills Power as part of its strategic workforce planning efforts. As operations at Neil Simpson I moved toward suspension, these employees assigned part of their time to the common Neil Simpson Complex facilities and also direct charged specific entities such as Cheyenne Light and Black Hills Wyoming. Once suspension of operations is complete, these employees will be transitioned to fill eight open positions at the Neil Simpson Complex.

Q. DOES THE RETENTION OF THE NEIL SIMPSON I EMPLOYEES ELIMINATE THE NEED TO INCLUDE GENERATION EMPLOYEES IN BLACK HILLS POWER'S FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM?

A. No. The retention of the Neil Simpson I employees merely addresses open positions that exist today. A need will still exist to hire and train individuals to fill positions that will be left vacant following future retirements. As a consequence, there are a number of generation positions included in Black Hills Power's FutureTrack Workforce Development Program.

Q. WHAT GENERATION POSITIONS ARE INCLUDED IN BLACK HILLS POWER'S FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM?

A. Instrument technicians, plant unit operators, and plant maintenance operators are the three generation positions that are included in the Program.

Q. PLEASE EXPLAIN WHY THESE POSITIONS ARE INCLUDED.

A. In the next eight years, Black Hills Power expects 7 instrument technicians, 4 plant maintenance operators, and 14 unit operators to retire. Based upon the Company's experience, it takes approximately 3 years to train an instrument technician and 1.5 years to train a plant maintenance operator to the level necessary for him/her to work independently and be considered as a candidate for a plant unit operator. Plant maintenance operators provide the pool of available candidates for unit operator positions. Once employed as a unit operator, it takes an additional 1.5 years before this category of employee is able to work independently. Due to the lengthy training periods and the shortage of skilled candidates, these three generation positions are included in the Black Hills Power's FutureTrack Workforce Development Program.

Q. HOW PRODUCTIVE ARE THE INDIVIDUALS WHO ARE TRAINING FOR THESE POSITIONS?

A. Based upon the Company's experience, an instrument technician is approximately 50 percent productive after 2 years of training, and able to work independently after 3 years of training; a plant maintenance operator is approximately 50 percent productive after 1 year of training, and able to work independently after 18 months of training; and a fully trained plant maintenance operator is approximately 50 percent productive as a unit operator after 1 year and able to work independently after 1.5 years of training. Jennifer Landis discusses how these productivity metrics are applied to determine what percentage of a particular position is charged to the Black Hills Power's FutureTrack Workforce Development Program regulatory asset.

XII. CONCLUSION

Q. PLEASE EVALUATE BLACK HILLS POWER'S GENERATION RESOURCES.

A. Once CPGS is in-service, Black Hills Power will have a balanced portfolio of geographically diverse modern coal and gas-fired generation that represents one of the newest fleets of generation resources in the United States. Black Hills Power's generation resources should provide its customers with reliable and economical energy for a very long period of time.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Direct Testimony
Kent J. Kopetzky

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. EL14-___

March 31, 2014

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Exhibits

None

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kent J. Kopetzky. My business address is 1102 East 1st Street, Papillion, NE, 68046.

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

A. I am currently employed as Senior Manager, Gas Supply Services for Black Hills Utility Holdings, Inc., ("BHUH"), which is a wholly-owned subsidiary of Black Hills Corporation ("BHC"). Gas Supply Services is a department within BHUH. Gas Supply Services is responsible for providing natural gas to regulated utility business units of BHC, including Black Hills Power ("Black Hills Power" or "Company").

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

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

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I obtained a Bachelor of Journalism degree in Broadcasting from the University of Nebraska-Lincoln in 1993. I have attended several utility industry conferences and workshops throughout my career in the utility industry. In addition to that ongoing work-specific education, I have also attended numerous conferences, meetings, and informal training sessions provided by interstate pipelines and natural gas suppliers providing natural gas products or services to the Company, and I was selected to be a member of the Gas Buyers Panel at the 2011 Midcontinent LDC Gas Forum.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE.

A. I joined BHUH as Manager, Gas Supply Services on July 16, 2008, and was appointed Senior Manager, Gas Supply, in September 2012. Prior to joining BHC, I served in multiple gas supply positions with Aquila, Inc. and its predecessor companies. For example, in 2006, I was appointed by Aquila, Inc. as Manager, Gas Supply Services.

I also served as a regulatory analyst in various positions, including preparation of gas supply cost adjustment compliance filings. I have over fifteen (15) years of experience in the utility industry with the majority of that experience in the area of procuring and managing natural gas supply, interstate transportation, and storage of natural gas for both natural gas and electric utilities. I coordinate my activities and responsibilities with other Gas Supply Services staff, including our portfolio and natural gas dispatching managers, to provide the Company's regulated utilities and their customers with reliable sources of natural gas.

Specifically, my work experience covers pipeline nominations, daily and monthly gas purchasing, and the development and support of natural gas requirements of natural gas fired power plants for BHC's regulated utilities.

II. <u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I will discuss the natural gas supply, pipeline capacity, and other fuel cost for the Cheyenne Prairie Generating Station project (hereafter "Cheyenne Prairie Generating Station" or "CPGS"). Gas Supply Services is responsible for arranging and managing the gas supply and pipeline capacity needed by the CPGS facilities.

The CPGS facilities are being constructed near Cheyenne, Wyoming to provide electricity to customers of Cheyenne Light, Fuel and Power Company ("Cheyenne Light") and Black Hills Power. This testimony will describe the actions taken by Black Hills Power or Gas Supply Services to ensure that natural gas is available at the CPGS facilities on those days when it is economical to generate electricity at CPGS for the customers of Black Hills Power and will address and support the natural gas fuel costs associated with generating that electricity.

Q. DID YOU PREPARE ANY EXHIBITS IN SUPPORT OF YOUR DIRECT TESTIMONY?

A. No.

III. <u>CPGS GAS SUPPLY</u>

Q. WHAT RECENT ACTIONS WERE UNDERTAKEN TO SERVE CPGS WITH NATURAL GAS?

A. Upon direction from Black Hills Power and Cheyenne Light, Fuel and Power Company ("Cheyenne Light"), Gas Supply Services solicited construction and transportation offers from multiple interstate natural gas transportation pipelines as part of Black Hills Power's natural gas supply planning for CPGS. Three bids were received in response to the solicitation. After further evaluation of the costs and benefits included within the various bids, Southern Star Central Gas Pipeline ("Southern Star") was selected as the interstate pipeline transportation provider for

CPGS. Southern Star built interconnecting facilities and a four mile lateral from its Rawlins-Hesston line in Colorado to an interconnection point with the Company's CPGS Pipeline[1], just north of the Wyoming – Colorado state line. Pursuant to a Certificate of Public Convenience and Necessity ("CPCN") granted by the Wyoming Public Service Commission in Docket Nos. 20002-81-EA-11 and 20003-113-EA-11 (Record No. 13007), Cheyenne Light and Black Hills Power are constructing the CPGS Pipeline, which originates at the Southern Star interconnection point just north of the Wyoming – Colorado State line and East of HWY 85 running to the North to CPGS.

Q. WHICH NATURAL GAS SUPPLIERS WILL PROVIDE THE GAS SUPPLY THROUGH SOUTHERN STAR AND THE CPGS PIPELINE?

A. There are currently no gas supply transactions in effect for gas supply through Southern Star and the CPGS Pipeline. Gas Supply Services will procure gas supplies in the future from a variety of natural gas suppliers as requested or as needed by Black Hills Power (i.e., electric generation or natural gas service) or Cheyenne Light.

Gas Supply Services has previously entered into industry-standard natural gas supply agreements with various natural gas suppliers (e.g., North American Energy Standards Board Agreement or NAESB). When Generation Dispatch and Power Marketing Department ("GDPM"), acting as agent for Black Hills Power or

[1] The CPGS Pipeline is a high pressure natural gas pipeline that is approximately ten and one-half (10.5) miles in length and twelve (12") inches in diameter that connects Southern Star to CPGS.

Cheyenne Light determines that a package of gas supply is needed to provide natural gas to CPGS, then Gas Supply Services will enter into specific negotiations with an existing supplier and thereafter execute a "Transaction Confirmation" with that natural gas supplier to deliver the package of natural gas at a receipt point on Southern Star in the agreed-upon quantities and at the agreed-upon price.

Gas Supply Services, acting as agent for Black Hills Power or Cheyenne Light will enter into additional NAESB agreements if needed to obtain gas supply from a particular natural gas supplier with which it does not already have an existing contractual relationship. The NAESB does not require any minimum consumption, and Gas Supply Services acting as agent for either Black Hills Power or Cheyenne Light will enter into specific gas supply transactions as identified by GDPM acting as agent for CPGS when gas is needed for CPGS.

The primary receipt point on Cheyenne Light's Firm Transportation agreement with Southern Star is Echo Springs, a Rockies point upstream of the CPGS interconnection which has historically enjoyed strong liquidity. Therefore, Gas Supply Services, as agent, will procure supply on a seasonal, monthly, and daily basis from reputable suppliers as needed for Black Hills Power at CPGS to generate power for its electric customers, or for Cheyenne Light at CPGS to generate power for its electric customers.

Q. WHEN WILL NATURAL GAS BE AVAILABLE AT CPGS?

A. As discussed in more detail below, the contract for firm interstate natural gas pipeline transportation capacity on Southern Star begins on October 1, 2014. CPGS Pipeline and Southern Star construction is expected to be completed prior to the start of CPGS testing in the summer of 2014. Thus, in addition to firm interstate transportation capacity, Cheyenne Light also entered into an interruptible interstate transportation capacity agreement with Southern Star for deliveries prior to October 1, 2014. That agreement does not require any minimum quantity use so it is available to be used as needed. As noted above, natural gas supply commodity is readily available on Southern Star. Thus, Gas Supply Services acting on behalf of either Black Hills Power or Cheyenne Light can enter into gas supply transactions for amounts needed to commence at that same time in the amounts identified by managers of CPGS.

IV. SOUTHERN STAR TRANSPORTATION AGREEMENTS

Q. WHAT ARE THE TERMS FOR THE INTERSTATE PIPELINE TRANSPORTATION AGREEMENT WITH SOUTHERN STAR?

A. The interstate pipeline Firm Transportation Agreement is between Cheyenne Light and Southern Star. The Firm Transportation Agreement and the Interruptible Transportation agreements with Southern Star are standard Southern Star tariff agreements. The rates, terms, and conditions of service under those interstate transportation agreements are regulated by the Federal Energy Regulatory Commission ("FERC"). The Firm Transportation Agreement is a maximum tariff rate agreement for 10,000 Dth per day. The Interruptible Transportation Agreement is at a discounted rate. The Firm Transportation Agreement commences on October 1, 2014 and will continue for seven years and seven months, expiring May 1, 2022, with a right of first refusal option to extend the term. The Interruptible Transportation Agreement goes into effect January 1, 2014 and therefore will be available for use during testing at CPGS.

Q. HOW WILL THE INTERSTATE PIPELINE TRANSPORTATION CAPACITY AND GAS SUPPLY REQUIREMENTS BE MANAGED?

A. Gas Supply Services, as agent for Black Hills Power and Cheyenne Light, will manage the use of the Southern Star interstate transportation capacity, and will enter into an Asset Management Agreement ("AMA"), interstate pipeline transportation capacity release agreements, Inter-Corporate Services, Agency, or make other arrangements with Black Hills Power and Cheyenne Light to fully manage this interstate pipeline transportation capacity on behalf of Black Hills Power and Cheyenne Light. Under similar agreements, Gas Supply Services will also manage the procurement of natural gas supply for Black Hills Power and Cheyenne Light, creating separate natural gas pools for each entity to ensure that each entity is allocated the appropriate commodity costs.

Q. IS THE LEVEL OF FIRM INTERSTATE PIPELINE CAPACITY ADEQUATE?

A. Yes. However, as noted above, in addition to the interstate pipeline Firm Transportation Agreement, Gas Supply Services acting on behalf of Black Hills

Power and Cheyenne Light has arranged for a discounted Interruptible Transportation contract if CPGS consumes more than 10,000 Dth of natural gas in a given day. As noted above, Gas Supply Services will obtain transportation for Black Hills Power through an AMA, or obtain interruptible transportation in Black Hills Power's name as appropriate or necessary.

V. OTHER GAS SUPPLY ARRANGEMENTS

Q. WILL HEDGES OR OTHER FINANCIAL DERIVATIVE ARRANGEMENTS BE USED?

A. Hedges and other financial derivatives will be used if market conditions indicate that it would be prudent to enter into such arrangements.

Q. WILL STORAGE BE ACQUIRED FOR CPGS?

A. There are several reasons why storage will not be purchased for CPGS at this time. Unlike many other pipelines, Southern Star does not currently charge daily out-of-balance fees, so storage is not needed to avoid daily balancing penalties. Also, as noted earlier, the primary receipt point on the Firm Transportation contract has historically been very liquid so supply should be easily attained. Finally, Southern Star currently has virtually no open storage capacity.

Q. WILL BLACK HILLS POWER PURCHASE NATURAL GAS SUPPLY FOR CPGS THAT IS PRODUCED LOCALLY?

A. No. Currently, the natural gas obtained for use at CPGS will be obtained through Southern Star.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Direct Testimony and Exhibit
Michael J. Fredrich

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. EL14-___

March 31, 2014

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael J. Fredrich. My business address is 409 Deadwood Avenue, P.O. Box 1400, Rapid City, South Dakota, 57701.

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

A. I am employed by Black Hills Utility Holdings Company ("BHUH") as Director, Engineering Services.

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

A. I am testifying on behalf of Black Hills Power, Inc. ("Black Hills Power" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS BACKGROUND.

A. I graduated from the South Dakota School of Mines and Technology with a Bachelor of Science Degree in Electrical Engineering in 1981. Following graduation, I accepted a position with Black Hills Corporation ("BHC"). Since that time, I have held a variety of engineering related roles.

From 1981 through 1986, I served as an electrical engineer in the Power Resources Department where I was responsible for the operation and maintenance of the generation and transmission protective relaying systems. From 1987 to 1988, I served as the Substation Maintenance Supervisor for Black Hills Power's Electric Operations Department. From 1989 to 1991, I served as the System Protection and Studies Engineer for the Black Hills Power System Engineering Department, where I performed system study work associated with the operational and planning requirements associated with the Black Hills Power 230 kV and 69 kV transmission networks. From 1991 to 2000, I was the Manager for Planning and Coordination for Black Hills Power. I was responsible for the development of operating and infrastructure plans associated with maintaining the adequacy and reliability of all 230 kV and 69 kV transmission electrical facilities. From 2000 to 2005, I was the Director of Transmission for Black Hills Power with responsibility for the entire transmission network, including transmission planning, transmission contracts, and Federal Energy Regulatory Commission ("FERC") tariff administration.

From 2005 to 2008, I was the Director of System Operations and Maintenance, Engineering, and Transmission for Black Hills Power. I was responsible for the operation and maintenance of the transmission network, including electrical maintenance, the 24 hour System Control Dispatch Center, all transmission planning activities, transmission contract administration, and FERC Open Access Transmission Tariff administration. I also had management responsibility over the Black Hills Power Engineering Department, which was responsible for the design and construction of the transmission and distribution networks of Black Hills Power. In 2008, I was named Director, Engineering Services. I continue in this role today.

Q. WHAT ARE YOUR PRIMARY RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As Director, Engineering Services, I currently manage and oversee the engineering, design, construction, operation, and maintenance functions associated with the major transmission and distribution networks of all three electric utilities currently under BHC, those entities being Black Hills Power, Cheyenne Light, Fuel & Power Company, and Black Hills/Colorado Electric Utility Company. I also have responsibility for the metering services, distribution planning, Geographic Information Systems electronic mapping, and drafting support services for these organizations.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide the Commission with a brief description of the Black Hills Power service territory and electrical network, a summary of the major capital distribution investments that are included in this rate case, and an overview of Black Hills Power's LIDAR project.

III. DISTRIBUTION GROWTH & RELIABILITY

Q. PLEASE DESCRIBE THE GEOGRAPHIC AREA OF BLACK HILLS POWER'S SERVICE TERRITORY.

A. Black Hills Power's service territory is located in the northeastern part of Wyoming, the western part of South Dakota (primarily the Black Hills of

South Dakota), and a portion of southeastern Montana. (See Exhibit MJF - 1 – Diagram of the BHP 230 & 69 kV transmission system). Please refer to the testimony of Vance Crocker for additional detail regarding Black Hills Power's service territory and business operations.

Q. PLEASE DESCRIBE THE METHODS THE COMPANY USES TO DETERMINE WHEN RELIABILITY AND GROWTH INVESTMENTS ARE APPROPRIATE OR REQUIRED.

A. Black Hills Power performs numerous power flow and voltage profile analyses on the Company's electrical transmission and distribution networks to determine the overall capability of the existing electric facilities to serve the projected customer peak loads during a typical near and long term planning cycle. It is through these planning studies that Black Hills Power is able to identify specific limitations associated with the existing transmission and distribution facilities that may prevent the Company from providing safe and reliable service to the Company's existing customers. It is also through this planning process that Black Hills Power will review, consider, and analyze specific system additions and improvements required to meet existing customer loads as well as the projected future customer loads. Black Hills Power has developed a detailed set of distribution planning standards and technical study criteria that it utilizes to evaluate and determine the best solutions required to meet load serving requirements of customers.

Q. PLEASE DESCRIBE THE TYPES OF INVESTMENTS NECESSARY TO MAINTAIN RELIABILITY OF THE DISTRIBUTION SYSTEM.

A. The types of investments associated with maintaining the reliability and integrity of the distribution and 69kV sub-transmission networks that have typically been considered in the Company's planning studies have been the following:

* Rebuilding of existing 69kV lines
* Upgrading of substation equipment
* New substation additions
* Rebuilding of distribution feeders
* New 69kV sub-transmission lines
* New distribution feeder circuits
* Voltage conversions
* Replacement of aged or damaged infrastructure

As potential projects are evaluated to address specific integrity, reliability, and growth requirements, Black Hills Power considers the cost benefit associated with the alternatives that may have been identified as reasonable solutions to a respective project. Black Hills Power takes into consideration a number of planning and economic variables as it reviews and evaluates a given project to consider reasonable cost alternatives for providing service to its customers.

IV. MAJOR CAPITAL DISTRIBUTION INVESTMENTS

Q. PLEASE IDENTIFY THE COMPANY'S RECENT MAJOR CAPITAL DISTRIBUTION INVESTMENTS.

A. The following provides a brief description of some of the major distribution capital investments that have been required to address various reliability and long term growth issues and that are included as part of this rate case.

a. The East Meade Substation Project.

The East Meade Substation Project consists of the construction of a 10.5/12/14 MVA – 69/12.4 kV substation and associated switchgear located in the southeastern part of Rapid City. This substation addition and associated distribution tie lines are required to support the loads currently served from the existing Robbinsdale Substation.

This project is necessary because the load service capability of the Robbinsdale Substation has reached its maximum capacity. The Robbinsdale Substation property site location is not conducive to physical expansion that would allow a larger transformer. The existing Robbinsdale Substation property site is also bordered by a drainage aqueduct on two sides of the property, which again poses various limitations to our ability to expand this location. Also, the ability to install additional distribution switchgear and associated distribution feeder exits was prohibited due to the geographical location of this substation.

The East Meade Substation location is outside of this residential area and will provide adequate access to the area distribution network. This new location will allow critical distribution ties to be constructed that will support the loads currently served from the Robbinsdale Substation. The additional transformer capacity at the East Meade Substation will also allow additional load support for loads served from adjacent substations during certain operating conditions and when back up support is needed during outage events. The location and capacity of the East Meade Substation will also provide additional system capacity and operating options to serve potential load growth in the southeastern portion of Black Hills Power's Rapid City service area.

The projected in service date for this project is September 30, 2014.

b. Neil Simpson Controls Project.

This project is associated with the decommissioning of the Neil Simpson I facility. This particular project will facilitate the relocation of all the control and protective relaying equipment required for the Neil Simpson 69 kV substation. This equipment is currently located within the physical confines of the Neil Simpson I power plant. The new control house will be located outside of the existing plant and be located near the 69 kV substation. The costs of this project include the installation of a new substation control building and the installation of new control and protective relaying equipment for the Neil Simpson 69 kV substation. The initial relocation of the existing controls from their power plant location into the new control building is anticipated to start in April 2014 and is currently scheduled to be completed by the end of May 2014.

c. Jackson Boulevard 69 kV Relocation Project.

This project is associated with a major South Dakota Department of Transportation road expansion/rebuild along Jackson Boulevard in Rapid City. This project will require Black Hills Power to relocate and rebuild approximately 3000 feet of existing single pole 69kV lines with 12.47 kV underbuild. This project is expected to be completed in July 2014.

d. Rapid City Cemetery Transformer Replacement.

The Rapid City Cemetery Transformer Replacement project involves replacement of the smaller of the two existing transformers (10.5 MVA) at this location so that both transformers have the same 14 MVA rating. Replacement is necessary because the smaller 10.5 MVA transformer can no longer support the summer peak loads in this area. This upgrade is also required to address system outages and reliability situations. The projected in service date for this project is late April 2014.

V. <u>LIDAR PROJECT</u>

Q. WHAT IS LIDAR?

A. LIDAR (Light Detection and Ranging) is a remote sensing technology that measures distance by illuminating a target with a laser and analyzing the reflected light. LIDAR surveys are performed by attaching the LIDAR device to an aircraft used to fly along the right-of-ways of the electric transmission and distribution facilities. The LIDAR imaging, coupled with high-resolution cameras, measures the distances between the particular facility, the ground, vegetation and other objects or structures within the vicinity of the facility.

Q. WHAT ARE THE BENEFITS OF LIDAR IMAGING?

A. LIDAR provides an economically appropriate imaging tool for areas with rough terrain and significant vegetation, such as the Black Hills. In particular, LIDAR imaging will provide Black Hills Power another tool to more accurately identify hazard trees and vegetation. LIDAR imaging will also assist Black Hills Power in measuring the distance between its power lines and the ground. As a consequence, Black Hills Power will be able to address inadequate clearances in a timely manner and therefore minimize line de-ratings caused by clearance issues.

Q. DOES THE NORTH AMERICAN ELECTRIC RELIABILITY CORPRATION ("NERC") RECOMMEND LIDAR IMAGING ON BHP'S 230 kV TRANSMISSION LINES?

A. Under NERC's facility rating reliability standard FAC-008, Black Hills Power is required to ensure that the facility ratings used in the reliable planning and operation of the Bulk Electric System are determined based on technically sound principles. Black Hills Power's 230kV transmission facilities fall under the definition of Bulk Electric System. As Black Hills Power continues to meet these facility rating requirements, it will utilize LIDAR surveys of its 230kV transmission facilities to validate and ensure it is maintaining the proper clearances so that it does not have to derate the loading on any of its facilities. In addition, Black Hills Power will also utilize these LIDAR surveys to better ensure compliance with the clearance requirements associated with NERC's Vegetation Management reliability standard FAC-003. The LIDAR technology and survey results will provide Black Hills Power with the most economical means of collecting electronic data on our facilities to perform these assessments.

Q. IS BLACK HILLS POWER PROPOSING TO PERFORM A LIDAR ANALYSIS OF ITS ENTIRE TRANSMISSION SYSTEM?

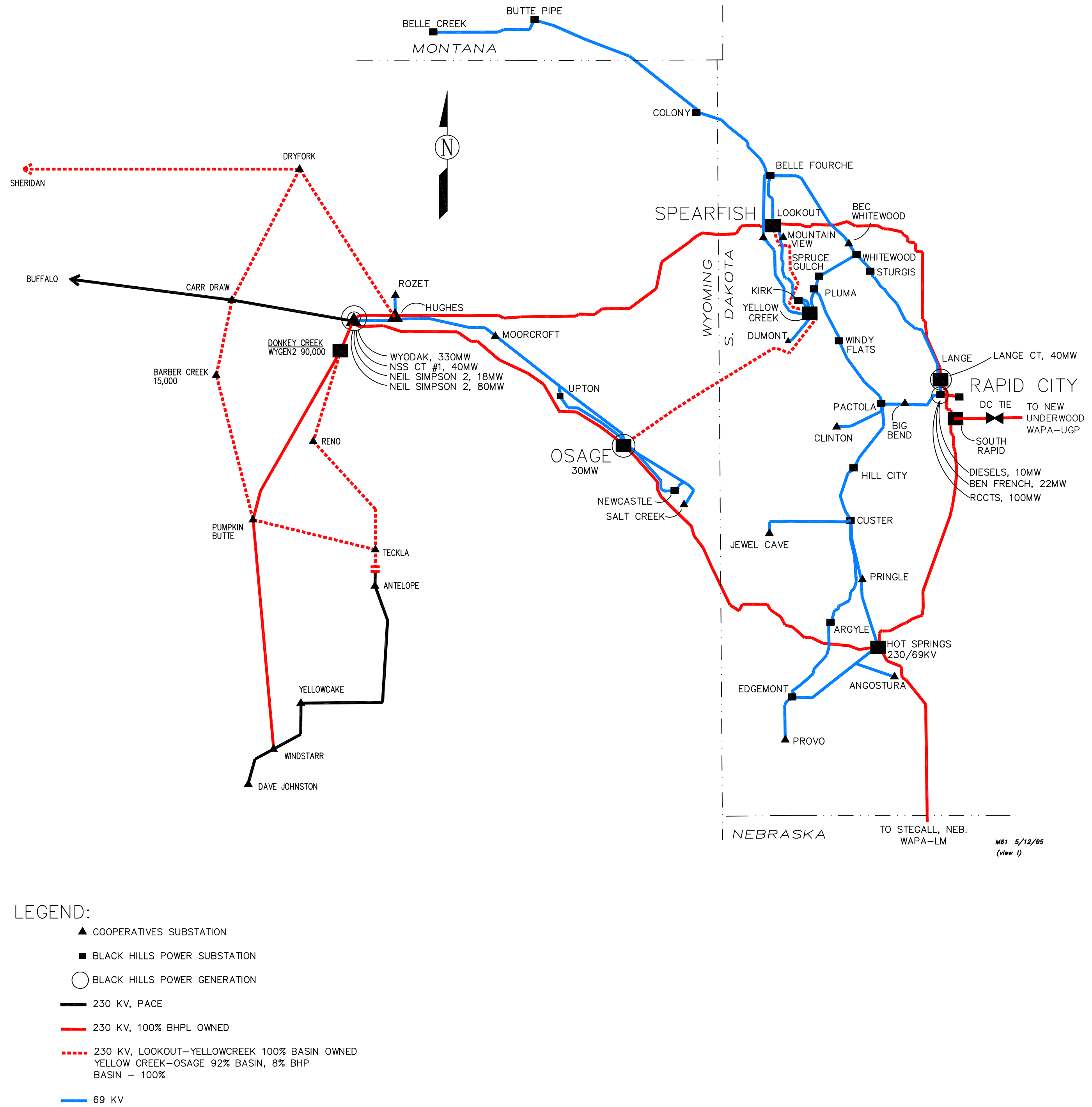
A. Yes. Black Hills Power plans to perform LIDAR imaging of all of its 230 kV and 69 kV facilities. This project will be started in 2014 after all snow is gone in the area and deciduous trees are fully leafed. Black Hills Power will hire an independent contractor to perform the LIDAR imaging. Based upon past experience of BHC, the cost estimate for this project is approximately $800,000 for the 69 kV system.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

230KV & 69KV TRANSMISSION SYSTEM

Exhibit MJF-1 Diagram of the BHP 230 & 69 kV transmission system



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Direct Testimony and Exhibits
Jennifer C. Landis

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. EL14-___

March 31, 2014

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Exhibits

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jennifer C. Landis. My business address is 625 Ninth Street, Rapid City, South Dakota 57701.

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

A. I am employed by Black Hills Service Company ("Service Company"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), as the Director, Corporate Human Resources and Talent Management.

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

A. I am testifying on behalf of Black Hills Power, Inc. ("Black Hills Power" or "Company").

Q. PLEASE BRIEFLY SUMMARIZE YOUR ACADEMIC AND PROFESSIONAL BACKGROUND?

A. I have a Bachelors Degree in Applied Management and a Masters Degree in Global Human Resources Development. I have over 18 years of experience in adult learning and development and 9 years in human resources with specializations in strategic workforce planning, leadership and employee development, succession planning, employee engagement, performance management, and project management. I am certified by the Human Capital Institute in Strategic Workforce Planning. I belong to several professional human resource organizations and speak publicly on human resources topics at association and industry conferences.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide: 1) a discussion regarding current industry workforce concerns; 2) an overview of Black Hills Power's current workforce; and 3) an explanation of the proposed FutureTrack Workforce Development Program, a recruitment and training program to address pending retirements.

II. <u>INDUSTRY WORKFORCE CONCERNS</u>

Q. PLEASE DESCRIBE THE CHALLENGES THE UTILITY INDUSTRY AS A WHOLE IS EXPERIENCING WITH ITS WORKFORCE REQUIREMENTS.

A. The utility industry is uniquely faced with an aging workforce and a scarcity of talent, especially technical talent. According to the 2013 Center for Energy Workforce Development ("CEWD") Gaps in the Energy Workforce Survey, the utility industry will likely replace up to 55% of its workforce due to retirement and attrition within the next 10 years. This impending wave of retirements, coupled with a decrease in the number of workers entering the industry, is well documented in several industry studies and white papers by the National Regulatory Research Institute, the California Public Utilities Commission, and the U.S. Department of Labor.

Q. ARE THERE ANY POSITION SPECIFIC STATISTICS THAT SUPPORT THIS CONCERN?

A. Yes. The CEWD study highlights line mechanics, technicians, plant operators, and engineers, and presents findings that 36% of these workers may be lost between 2013 and 2017 through attrition and retirement. In addition to the number of employees leaving the job market, other industry data demonstrates an alarming lack of candidates available to fill these openings. For example, the table below provides nationwide data regarding the number of active candidates and job openings for a number of typical utility jobs:

Position	Active Candidates in US	Job Postings in US
Instrument Controls Technician	6,116 candidates	6,654 open jobs
Lineman (Line Mechanic)	2,380 candidates	6,622 open jobs
Plant Maintenance Operator	7,936 candidates	12,483 open jobs
Substation Electrician	1,682 candidates	2,188 open jobs
Unit Operator	3,089 candidates	4,405 open jobs

These statistics illustrate the challenges the industry is facing with respect to filling critical role vacancies.

Q. ARE LOCAL UTILITIES ALSO EXPERIENCING A SHORTAGE OF ELIGIBLE CANDIDATES TO FILL CRITICAL POSITIONS?

A. Yes. According to statewide industry data, there were zero substation electricians seeking employment in South Dakota from January 2012 to December 2013, but there were 8 openings. During the same period, there were 35 line mechanics seeking South Dakota employment, with 30 job postings. In the power generation field, there were only 45 plant maintenance operators seeking employment in Wyoming, with 232 job openings. There were 70 unit operators also looking for work in Wyoming, with 146 job openings. Lastly, there were 19 instrument control technicians searching for Wyoming employment and 32 job openings.

III. BLACK HILLS POWER'S WORKFORCE

Q. IS BLACK HILLS POWER FACING THE SAME CHALLENGES AS THE UTILITY INDUSTRY REGARDING IMPENDING RETIREMENTS?

A. Yes. As of January 31, 2014, Black Hills Power employed approximately 265 people. Over the next 8 years, approximately 31% of Black Hills Power's current workforce will reach the age of 62, which has been the historical average age of retirement of employees at Black Hills Power and its parent, BHC.

Q. DOES THE IMPENDING WORKFORCE LOSS CAUSE ANY CONCERN?

A. Yes. The magnitude of impending retirements causes the Company great concern. The employees expected to retire in the next eight years represent over 50% of total years of experience with the Company. Many of the roles most critical to Black Hills Power operations have a particularly high retirement risk. The following table illustrates this point.

Position	2013 Headcount	Expected Retirements Over 8 Years	Expected Retirement Percent
Construction Representative	7	3	42.9%
Electrician	8	5	62.5%
Line Mechanic	43	13	30.2%
Unit Operator	24	14	58.3%
Instrument Technician	13	7	53.8%
Energy Services Technician	4	2	50.0%
Plant Maintenance Operator	40	4	10.0%
Meter Technician	6	3	50.0%

The impending loss of critical institutional knowledge, especially in jobs that have significant technical skills requirements, presents a risk to the Company and its ability to continue to efficiently provide safe and reliable service.

Q. WHAT STEPS HAS BLACK HILLS POWER UNDERTAKEN TO ADDRESS THESE CONCERNS IN THE PAST?

A. BHC has implemented strategic workforce planning processes and practices at each of its utility business units, including Black Hills Power. The strategic workforce planning process includes an examination of the current workforce demographics, projections of potential losses due to employee retirement over the next 5 to 8 years, and a thorough discussion of the skills and knowledge that will be needed to serve our customers. Through this process, Black Hills Power has identified specific areas of risk due to an alarming shortage of workers possessing specialized skills and gaps in unique organizational and systems knowledge.

Q. WHAT STEPS ARE BLACK HILLS POWER CURRENTLY TAKING TO ADDRESS THIS CRITICAL WORKFORCE ISSUE?

A. Building on efforts already underway at Black Hills Power, the company has created a comprehensive strategic workforce planning program – the FutureTrack Workforce Development Program – which will involve the hiring, training, and preparation of new workers to perform the specialized and critical work necessary to continue providing Black Hills Power's customers and communities with the safe and reliable service they depend upon. This is a company-wide initiative that BHC will implement at each of its utility subsidiaries.

IV. FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM

Q. PLEASE PROVIDE A GENERAL OVERVIEW OF THE FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM.

A. The primary function of the FutureTrack Workforce Development Program is to recruit talent within critical areas to complete the advanced training necessary to fill the highly skilled positions upon retirement of existing employees. The training provided to employees hired into the FutureTrack program will be flexible and innovatively tailored to the education and experience level of the individual employee. Most of the training will occur on the job and under very close supervision. Some positions will require bookwork, classroom based training, and examinations. In addition, potential candidates may be offered a scholarship, covering tuition, books, and tools, to a South Dakota vocational school to receive training necessary to meet minimum qualifications for FutureTrack positions. A program description is included in Exhibit JCL-1.

Q. PLEASE EXPLAIN WHY BLACK HILLS POWER NEEDS TO HIRE IN ADVANCE OF RETIREMENTS.

A. Black Hills Power relies on skilled labor to safely and reliably deliver electricity to its customers. These roles are technically complex and take years of study and application before competence is achieved. The learning period for these jobs far exceeds the typical amount of notice Black Hills Power would receive from employees giving notice of their intent to retire. To keep up with the loss of talent caused by retirements, Black Hills Power must begin training and hiring replacement workers well in advance of expected retirements. Given the scarcity of qualified replacements, Black Hills Power will not be able to meet its workforce demands by hiring off the street or from within the industry, as it has in the past.

Q. WHAT POSITIONS HAVE BEEN IDENTIFIED FOR INCLUSION IN THE PROGRAM?

A. The FutureTrack program includes line mechanics, sub-station electricians, construction representatives, energy services technicians, meter technicians, unit operators, plant maintenance operators, instrument and controls technicians, and information technology developers. Also included in the program is a category of positions called operations support and management roles. This group of positions is included due to the nature of the skills, knowledge, and advanced training necessary for success in these roles. Roles included in the other support and management category include: operations management, GIS analysts, systems operators, system operations analysts, energy services representatives, and generation dispatch/power marketing roles.

Q. WHY WERE THESE POSITIONS SELECTED FOR INCLUSION?

A. The positions selected for inclusion will have the following characteristics: the role is critical to Black Hills Power operations; the role requires unique or specialized skills and knowledge with a minimum requirement of six months advanced training to achieve competence; the role is difficult to fill or requires a unique or specialized skill set; and the role has incumbent employees who will reach age 62 within the next 4-8 years.

Q. HOW DID BLACK HILLS POWER FORECAST ITS WORKFORCE NEEDS?

A. Black Hills Power's workforce was assessed to determine retirement risk by job function and/or position. The determining factor was employee age. Historical retirement data demonstrates that long-tenured, pension eligible employees retire almost exactly at age 62. Once the retirement risk was determined for each job function, interviews were conducted with Black Hills Power business unit managers and human resource support staff, and collective bargaining unit agreements were consulted.

Q. DESCRIBE THE TYPICAL EXPERIENCE PROFILE OF A FUTURETRACK EMPLOYEE?

A. There is no typical experience profile. The FutureTrack program will recruit both inexperienced and partially qualified workers. One focus of the FutureTrack program will be to identify and recruit high school students during their junior or senior year of high school. These students will receive scholarships to a South Dakota vocational school appropriate for the position they are selected to fill. The program will also target re-training more mature workers who are interested in entering the utility industry (e.g., former military personnel returning to South Dakota).

Q. PLEASE EXPLAIN WHY A SCHOLARSHIP COMPONENT IS INCLUDED IN THE PROGRAM.

A. Many of the jobs in the FutureTrack program require technical school certificates or college degrees for consideration. Additionally, the majority of skilled utility workers are approaching retirement. A different approach is necessary to attract the sufficient numbers of people from the next generation to work in the utility industry. The intent is to create South Dakota training for South Dakota residents to fill South Dakota jobs.

Q. PLEASE EXPLAIN HOW THE SCHOLARSHIP COMPONENT OF THE PROGRAM WILL BE IMPLEMENTED.

A. Of the FutureTrack jobs that require technical school certificates or college degrees, roughly 50% of the FutureTrack positions expected to be filled over an eight year period will receive scholarships. Technical school scholarships will include tuition, books, and tools (as applicable). Recipients of full scholarships, for example, will be asked to sign a letter of intent to work for Black Hills Power upon graduation, with the stipulation that if the recipient decides not to work for

Black Hills Power for at least two years, the recipient must repay Black Hills Power the sum of their scholarship. For positions requiring a college degree, a scholarship will be offered to support the last year of the degree. The same letter of intent with the payback stipulation will be used. These scholarships will send South Dakota residents to South Dakota schools to prepare for South Dakota jobs at Black Hills Power.

Q. ARE YOU AWARE OF ANY OTHER COMPANIES THAT ARE OFFERING SCHOLARSHIPS TO POTENTIAL EMPLOYEES?

A. Yes. Approximately 25 companies are working with Mitchell Technical Institute ("MTI") to provide scholarships for MTI students that require employment with the sponsoring company following graduation. These scholarships require the recipient to work for the sponsoring company for a pre-determined number of years.

Q. WHAT ARE THE OVERALL COSTS TO CUSTOMERS ASSOCIATED WITH THE FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM?

A. The anticipated total annual cost to customers for the program is $721,861 for each of the next eight years. This includes costs associated with labor and benefits, scholarships, relocation, and training as shown in the table below. As described in the testimony of Chris Kilpatrick, Black Hills Power is requesting that expenditures for the program that exceed $721,861 annually over each of the next eight years be recorded in a regulatory asset. If in any of the eight years the annual expenditures are less than $721,861, the amount of the difference will be credited to customers through the regulatory asset. For additional information regarding the requested treatment of these costs, please refer to the testimony of Chris Kilpatrick.

Expense Type	**Estimated Annual Cost**
Labor & Benefits	$652,200
Relocation	$31,400
Scholarships	$21,200
Training	$17,100
Total	**$721,900**

Q. PLEASE PROVIDE AN EXAMPLE OF HOW THE COSTS FOR ONE FUTURETRACK EMPLOYEE WOULD FLOW THROUGH THE PROGRAM.

A. The table below shows the progression of a newly recruited high school student into the FutureTrack program and follows his or her progress through the entire training period.

Year	Expense Type	Regulatory Account Cost	BHP Cost	Notes
0	Scholarship to Mitchell Technical Institute's Power Line Construction & Maintenance Program	$13,400		Scholarship covers tution, books, fees, and tools for the 2 semester program
1	Relocation cost	$5,000		
	Training Cost (IBEW course work)	$1,110		Covers IBEW's line mechanic certification course
	Labor & Benefits	$78,741		
2	Training Cost (IBEW course work)	$1,110		Covers IBEW's line mechanic certification course
	Labor & Benefits	$90,799		
3	Labor & Benefits	$51,706	$54,181	Employee is able to begin working independently in year 3; costs are shared by BHP
4	Labor & Benefits		$109,060	Employee transitions out of FutureTrack program and replaces a retiring BHP line mechanic

Not all FutureTrack employees will receive scholarships or relocation. This example shows how all elements of the program, if used and necessary, are applied. A complete description of the developed revenue requirement for the FutureTrack program is included as Exhibit JCL-2.

Q. IS A FUTURETRACK EMPLOYEE'S COMPENSATION CHARGED TO THE FUTURETRACK REGULATORY ACCOUNT DURING THE ENTIRE TRAINING PERIOD?

A. Employee compensation costs are fully charged to the regulatory asset during the initial training period, the length of which varies for each position. Once the employee begins to gain competence and can begin to do some independent work, however, the costs begin to shift from the regulatory account to Black Hills Power capital and operations and maintenance accounts. As described in the testimony of Vance Crocker and Mark Lux, productivity metrics were developed for individual FutureTrack positions. These metrics are applied to estimate the percentage and timing of moving compensation expenses from the regulatory asset to Black Hills Power. By the end of the training period, the entire compensation cost is covered by Black Hills Power and the employee will transition into regular full-time employment as another employee is retiring. Please refer to the testimony provided by Vance Crocker and Mark Lux for more information regarding transitioning employees from a training role into an active employment role.

Q. HOW DOES BLACK HILLS POWER PLAN TO TRACK THE COSTS ASSOCIATED WITH THE FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM?

A. Each FutureTrack employee-in-training will be tracked using a custom field in our human resources management system. FutureTrack has accounts created to allow our financial systems to capture and report all expenses associated with the labor, benefits, relocation, scholarship, and training of FutureTrack employees.

Q. WHAT ARE THE BENEFITS OF THE FUTURETRACK PROGRAM FOR CUSTOMERS?

A. Black Hills Power's employees are the most important element of the Company's ability to meet its obligation to serve. Given the certainty of upcoming retirements, and the dramatic shortage of qualified utility-industry job applicants, innovative solutions are required. By training and preparing workers in advance of retirement, long-tenured and experienced workers are given the time and opportunity to transfer their knowledge of the job, the customers, the company culture, and the skills they've honed over their 30-plus years in a specialized role with Black Hills Power. This knowledge transfer over time translates to increased understanding, compliance, safety, and overall performance. It creates a deeper sense of engagement and integration into the workgroup and Company for both the retiring worker and the FutureTrack employee-in-training, which decreases turnover, increases retention, and improves efficiency, system safety, and reliability. Combined, these benefits decrease unnecessary costs due to preventable incidents, inefficiencies, and knowledge loss. The FutureTrack program is good for our customers, our communities, and for Black Hills Power.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BHP Rate Case Exhibit: FutureTrack Workforce Development Program

The Purpose: This program is being created to offset the large number of retirements exiting Black Hills Power's workforce over the next eight years by training and preparing new workers to perform the specialized and critical work necessary to continue providing the safe, reliable service Black Hills Power's customers depend upon.

Forecasting Workforce Needs: All positions at Black Hills Power were evaluated to identify the utility's most critical workforce needs. Positions were reviewed to determine: 1) if unique or specialized skills and knowledge are required to perform the job safetly; 2) if the position is critical to operations or directly supports critical operations; 3) if retirement within the role's current incumbents creates risk to the utility's ability to provide safe, reliable service; 4) if there is at least a 6 month training time required to reach full productivity/competence before the employee can work independently; and 5) if there is limited availability to find replacement workers in the labor pool/external market.

Positions included in the FutureTrack Workforce Development Program (FutureTrack) are critical. Workforce needs created through the loss of experienced workers through retirements must be managed proactively and prudently.

FutureTrack Positions:

Applying the criteria listed above resulted in the following positions inclusion in the FutureTrack Workforce Development Program:

1. Line Mechanics
2. Electricians
3. Construction Representatives
4. Energy Services Technicians
5. Meter Technicians
6. Unit Operators
7. Plant Maintenance Operators
8. Instrument and Controls Techs
9. Information Technology Developers
10. Other Operations Support and Management Roles: *This group of roles was included due to the nature of the skills and knowledge required; however, there is not currently a need to hire duplicate staff in these areas. Should there be unexpected retirements or a change in business needs that would put safe, reliable service at risk, duplicate hires would need to be made in these positions.*
    - Operations Management
    - GIS Analysts
    - Systems Operators and System Operations Analysts

- Energy Services Representatives
- Generation Dispatch/Power Marketing roles

Participant Criteria & Selection: Any candidate who applies for and meets the minimum qualifications for a posted FutureTrack postion will be considered for employment under the program. Minimum qualifications will vary based on the posted position's requirements.

Program Length: The length of the FutureTrack program depends on the job an employee-in-training is hired into and the experience that individual brings with them into the job. The least amount of time an employee-in-training will spend in the program is 6 months and the greatest is 4 years.

Program Components: The FutureTrack program includes some scholarships and relocation, onboarding, and training (classroom and on-the-job) for employees in the program.

> **Scholarships:** Many of the jobs in the FutureTrack program require technical school or college degrees. To fill these jobs, scholarships have been included in the FutureTrack program. These scholarships will send South Dakota residents to South Dakota schools to prepare for South Dakota jobs at Black Hills Power.
>
> **Relocation:** In some cases, relocation may be necessary. The FutureTrack program includes limited relocation dollars to assist employees-in-training to relocate themselves and their families to/near Black Hills Power service areas.
>
> **Onboarding:** All FutureTrack employees will go through a comprehensive onboarding program. The onboarding program will include all elements traditionally covered with Black Hills Power employees, but will also contain additional material about their responsibilities as FutureTrack employees-in-training.
>
> **Training:** The specific training requirements vary for each position in the FutureTrack program. Many of the positions are tied to apprenticeships, while others require specialized training of a different variety. Because many of the individuals historically hired into Black Hills Power positions have had prior utility experience, it is anticipated that additional training will likely be needed to support FutureTrack employees-in-training who will bring little to no prior utility experience.

Tracking & Reporting: All activities associated with the FutureTrack program will be recorded and reported to the commission annually.

Estimated Total Program Cost:

> **Cost to Customers**: The anticipated total annual cost to customers for the program is $721,900. This includes costs associated with labor and benefits, scholarships, relocation, and training.

Productivity Adjustments: As FutureTrack employees-in-training gain the knowledge and experience needed to work productively, their labor and benefit costs will be shared and eventually transferred fully to Black Hills Power. Each position in the FutureTrack program has a different training timeline and productivity curve, which was used to determine the amount of the cost sharing between customers and Black Hills Power.

Program Expense True-Up: Retirement decisions are highly personal and workers may decide to alter their retirement plans to either work longer or retire sooner. Because of this, the cost of the program is expected to fluctuate over time. In addition to reporting the program's staus to the commission annually, we recommend a true-up audit be performed in 5 years. Any expenses planned for but not realized will be returned to Black Hills Power customers. Likewise, any reasonable and documented expenses that exceed the approved FutureTrack regulatory account will be brought before the commission for reimbursement.

Black Hills Power - Strategic Workforce Planning Hire Ahead Program

State	Job Function	Bargaining Unit	Avg Annual Wage Adj for Productivity	Loading Less Compensated Absences	Fully Loaded Annual Salary	BHP Ownership % / CAM %	SWP Program Avg Annual Labor Cost	Total Labor Cost of SWP Advanced Hire	Training & Transition Period Req'd (in yrs)	Average Annual Cost of SWP Advanced Hire	Training Cost per Hire Ahead
SD	Construction	Non Union	$ 46,240	69%	$ 78,145	100%	*$78,145*	$156,291	2.0	$78,145	$5,000
SD	Electrician	BHP Local 1250	$ 40,149	58%	$ 63,436	100%	*$63,436*	$190,308	3.0	$63,436	$8,500
SD	Line Mechanic	BHP Local 1250	$ 42,386	58%	$ 66,970	100%	*$66,970*	$200,910	3.0	$66,970	$2,213
WY/SD	Unit Operators	BHP Local 1250	$ 44,351	58%	$ 70,075	38%	*$26,628*	$40,000	1.5	$20,000	$760
WY	Instrument	Non Union	$ 48,932	69%	$ 82,695	38%	*$31,424*	$94,273	3.0	$31,424	$4,180
SD	Energy Services Techs	BHP Local 1250	$ 36,478	58%	$ 57,635	100%	*$57,635*	$57,635	1.0	$57,635	$2,000
WY	Plant Maintenance	BHP Local 1250	$ 29,321	58%	$ 46,328	38%	*$17,605*	$26,407	1.5	$13,203	$760
SD	Information Technology	Non Union	$ 32,526	65%	$ 53,668	21%	*$11,270*	$11,270	1.0	$11,270	$1,575
SD	Meter Technicians	BHP Local 1250	$ 48,336	58%	$ 76,370.90	100%	*$76,371*	$152,742	2.0	$76,371	$6,000
	Other Positions		$ 45,760	65%	$ 75,504.00	30%	*$22,651*	$22,651	1.0	$22,651	$1,540

Black Hills Power - Strategic Workforce Planning Hire Ahead Program

Line No.	State	Job Function	Avg. Acquisition Cost per Hire Ahead	Total Cost of 1 SWP Advanced Hire	2013 Headcount	2014	2015	2016	2017	2018	2019	2020	2021	8 yr Total for Job Function	Hire-Aheads Proposed
						Anticipated Retirees based on Age 62									
1	SD	Construction	$43,292	$204,582	7	1			1		1			3	
2				*Replacement Costs (Not included):*		1									1
3				*Duplicate hire Count:*				1		1					2
4				*Duplicate hire Cost yr 1:*		$0	$0	$126,437	$0	$126,437	$0	$0	$0		$409,164
5				*Carrying costs yr 2:*			$0	$0	$78,145	$0	$78,145	$0	$0		
6	SD	Electrician	$8,750	$207,558	8	2		1			1	1		5	
7				*Replacement Costs (Not included):*		0									0
8				*Duplicate hire Count:*		1			1	1					3
9				*Duplicate hire Cost yr 1:*		$80,686	$0	$0	$80,686	$80,686	$0	$0	$0		$622,673
10				*Carrying costs yr 2:*			$63,436	$0	$0	$63,436	$63,436	$0	$0		
11				*Carrying costs yr 3:*				$63,436	$0	$0	$63,436	$63,436	$0		
12	SD	Line Mechanic	$9,392	$212,515	43	3		1		4	2	2	1	13	
13				*Replacement Costs (Not included):*											0
14				*Duplicate hire Count:*		4		4	2	2	1				13
15				*Duplicate hire Cost yr 1:*		$314,301	$0	$314,301	$157,151	$157,151	$78,575	$0	$0		$2,762,698
16				*Carrying costs yr 2:*			$267,880	$0	$267,880	$133,940	$133,940	$66,970	$0		
17				*Carrying costs yr 3:*				$267,880	$0	$267,880	$133,940	$133,940	$66,970		
18	WY/SD	Unit Operators	$0	$40,760	24	2	1	2	2	4	2	0	1	14	
19				*Replacement Costs (Not included):*		2									2
20				*Duplicate hire Count:*		1	2	2	4	2	0	1			12
21				*Duplicate hire Cost yr 1:*		$27,427	$54,853	$54,853	$109,707	$54,853	$0	$27,427	$0		$489,120
22				*Carrying costs yr 2:*			$13,333	$26,667	$26,667	$53,333	$26,667	$0	$13,333		
23	WY	Instrument	$17,201	$115,654	13	2			1		2	2		7	
24				*Replacement Costs (Not included):*		2									2
25				*Duplicate hire Count:*		1		2	2						5
26				*Duplicate hire Cost yr 1:*		$52,805	$0	$105,611	$105,611	$0	$0	$0	$0		$578,269
27				*Carrying costs yr 2:*			$31,424	$0	$62,848	$62,848	$0	$0	$0		
28				*Carrying costs yr 3:*				$31,424	$0	$62,848	$62,848	$0	$0		
29	SD	Energy Services Techs	$7,500	$67,135	4	1			1					2	
30				*Replacement Costs (Not included):*		1									1
31				*Duplicate hire Count:*				1							1
32				*Duplicate hire Cost yr 1:*		$0	$0	$67,135	$0	$0	$0	$0	$0		$67,135
33	WY	Plant Maintenance	$0	$27,167	40	1			1			1	1	4	
34				*Replacement Costs (Not included):*		1									1
35				*Duplicate hire Count:*				1			1	1			3
36				*Duplicate hire Cost yr 1:*		$0	$0	$18,365	$0	$0	$18,365	$18,365	$0		$81,501
37				*Carrying costs yr 2:*			$0	$0	$8,802	$0	$0	$8,802	$8,802		
38	SD	Information Technology	$3,780	$16,625	5			1	1	1	2			5	
39				*Replacement Costs (Not included):*											0
40				*Duplicate hire Count:*			1	1	1	2					5
41				*Duplicate hire Cost yr 1:*		$0	$16,625	$16,625	$16,625	$33,251	$0	$0	$0		$83,126
42	SD	Meter Technicians	$0	$158,742	6	1						1	1	3	
43				*Replacement Costs (Not included):*		1									1
44				*Duplicate hire Count:*						1	1				2
45				*Duplicate hire Cost yr 1:*		$0	$0	$0	$0	$82,371	$82,371	$0	$0		$317,484
46				*Carrying costs yr 2:*			$0	$0	$0	$0	$76,371	$76,371	$0		
47		Other Positions	$6,119	$30,310		2	2	2	2	2	2	2	2	16	
48				*Replacement Costs (Not included):*		2	2								4
49				*Duplicate hire Count:*			2	2	2	2	2	2			12
50				*Duplicate hire Cost yr 1:*		$0	$60,621	$60,621	$60,621	$60,621	$60,621	$60,621	$0		$363,724
				Totals:										72	
				Replacement Costs (Not included):		10	2	0	0	0	0	0	0		12
				Duplicate hire Count:		7	5	14	12	11	5	4	0		**58**
				Annual SWP Program Cost:		$475,219	$508,173	$1,153,355	$974,743	$1,239,655	$878,715	$455,931	$89,106		**$5,774,895**

Average per year (based on 8 years): **$ 721,862**

Direct Testimony
Laura A. Patterson

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. EL14-___

March 31, 2014

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Exhibits

None

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Laura A. Patterson and my business address is 625 9th Street (4th Floor), Rapid City, South Dakota 57701.

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

A. I am employed by Black Hills Service Company, ("Service Company"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), as the Director of Compensation, Benefits and Human Resources Information Systems ("HRIS"). In my position, I am responsible for partnering with business leaders to design and execute compensation and benefits strategies and plans. I also provide input related to strategic planning, implementation and administration of compensation and benefits programs, executive plans, equity programs, non-qualified plans and other initiatives. My responsibilities also cover employees working for Black Hills Power, Inc. ("Black Hills Power" or the "Company").

Q. PLEASE BRIEFLY SUMMARIZE YOUR ACADEMIC AND PROFESSIONAL BACKGROUND?

A. I have more than 23 years of experience in compensation and benefits, with responsibilities including the development, management, administration and regulatory compliance of such plans. I began my current position as Director of Compensation, Benefits and HRIS for BHC in April 2009. Prior to this position, I spent 6 years as Director of Compensation, Benefits and HRIS and 2 years as Employee Benefits Manager, for PNM Resources, Inc. (PNMR), where I was responsible for managing and administrating all compensation and benefit programs for PNMR, its subsidiaries and for its joint venture business with Cascade Investments, Optim Energy. Prior to working for PNMR, I was employed as a Tax Manager and Human Capital Consultant for four years at Arthur Andersen, a global tax and consulting firm. In this position, I worked with organizations to identify, analyze and apply regulatory rules that govern structure, compliance, and administration of employee benefit plans. Prior to Arthur Andersen, I was employed as a Trust Officer at Mercantile Trust Company from 1995 to 1999 with responsibilities for managing and administration of profit sharing, 401(k), and pension purchase retirement plans sponsored by a wide range of clients. I have a Bachelor of Business Administration degree from the University of Iowa.

Q. HAVE YOU PROVIDED TESTIMONY IN REGULATORY PROCEEDINGS PRIOR TO THIS CASE?

A. Yes. I have previously testified in New Mexico PRC Case No. 06-00210-UT, a gas rate case, in New Mexico PRC Case No. 07-00077-UT, an electric rate case, in Texas PUC Case Docket No. 36025, an electric rate case, in Nebraska PUC Case Docket No. NG-0061, a gas rate case, and in Colorado PUC Case Docket No. 11-AL-382E, an electric rate case. I have also submitted testimony in Black Hills Power's last rate application with the South Dakota PUC, Docket No. EL 12-061. Finally, I testified on behalf of Cheyenne Light before the Commission in Cheyenne Light's 2009 and 2011 electric and natural gas rate proceedings.

Q. DESCRIBE YOUR PROFESSIONAL ASSOCIATIONS.

A. I served on the Corporate Board of Directors of the International Foundation of Employee Benefit Plans and currently serve on the Employee Benefits Committee for the U.S. Chamber of Commerce. I am also a Certified Retirement Services Professional.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. Black Hills Power.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I describe and support the general compensation program for BHC employees, and particularly the employees of Black Hills Power, including the variable compensation program and the equity compensation program. I explain why these programs and their associated costs are reasonable and necessary to attract, motivate and retain well qualified and competent employees to support utility operations. Black Hills Power employees, both non-union and union, participate in the compensation and benefit plans sponsored by BHC.

I also describe and support the general benefits programs and policies for BHC employees, particularly the employees of Black Hills Power, including the health, welfare and retirement benefits, and explain why those programs and their associated costs are reasonable and necessary.

My testimony specifically supports employee compensation related adjustments, including base salary, variable compensation, equity compensation, retiree healthcare, pension plan, pooled medical, and 401(k) plan, that are part of the overall benefits adjustment. Finally, my testimony will explain the adjustments related to personnel due to the suspension of operations at certain facilities.

II. COMPENSATION PHILOSOPHY AND PROGRAMS

Q. WHAT IS BHC'S GENERAL COMPENSATION PHILOSOPHY?

A. BHC's long-term success depends on operational excellence, providing reliable products and services to our customers, and investing wisely to ensure present and future strength. BHC's strength allows us to invest in our utility infrastructure and systems to improve the safe, reliable and affordable service our customers and communities depend on. To consistently achieve these outcomes, BHC must attract, motivate and retain employees to achieve appropriate business results. For these reasons, BHC promotes a compensation program that supports the overall operational excellence and customer service objectives, based on principles designed to:

- attract, motivate, retain and encourage the development of highly qualified employees;
- provide compensation that is competitive;
- promote the relationship between pay and performance;
- promote overall performance that is linked to our customers and shareholders; and
- recognize and reward individual performance appropriately.

All compensation programs are designed to be strategically aligned, externally competitive, internally equitable, personally motivating, cost effective and legally compliant.

Q. PLEASE DESCRIBE BHC'S COMPENSATION PROGRAMS.

A. There are two primary components to the compensation program – Base Salary and Variable Pay programs.

- Base Salary: Base salary represents the fixed portion of an employee's total cash compensation opportunity. Base salary compensation is determined by the market value of the job, the experience level of the employee, and specific performance standards and competencies. Base salaries are reviewed on an annual basis and merit salary increases are based on individual performance and contributions. Base rates of pay for Black Hills Power's union employees are established under the terms of the collective bargaining agreement with the International Brotherhood of Electrical Workers ("IBEW") Local 1250.
- Variable Pay: Variable Pay is pay that is "at risk" and is not fixed or guaranteed. Variable Pay is only earned and awarded based on achievements against specific performance-based goals. All BHC employees (non-union and union) participate in the Annual Incentive Plan (AIP) which is described in detail later in this testimony.

Q. PLEASE EXPLAIN BHC'S PHILOSOPHY ON BASE PAY COMPENSATION.

A. Base pay is intended to reflect the median of the market for similar positions in similar companies. Overall, our goal is to target direct compensation (base salary and variable pay / annual incentives) at the median of the appropriate market when our operating results approximate average in relation to our peers.

There are twenty-three (23) pay grades which are used for all non-executive, non-union jobs. Each grade has a minimum, midpoint, and a maximum pay level. This means that the pay ranges within the grades are competitive with what other companies pay for similar positions. All jobs are compared to the market, where data exists, and placed in the grade where the midpoint of the range is closest to the average market rate for that job. In 2009, Towers Watson conducted an independent market review of the BHC's positions and benchmarked each position. Each position was placed in the appropriate salary grade, reflecting the market median values. Subsequent to the Towers Watson study, the BHC Human Resources Compensation Department periodically reviews each position in the company and compares it to credible market survey data to ensure that current compensation remains within the competitive range.

Market rates are determined by utilizing compensation survey data where companies report actual compensation paid to employees by position. The survey most widely used by BHC is from Towers Watson, as they are recognized nationally as the leader in the energy services / utility market place.

Q. IN ADDITION TO THE TOWERS SURVEY, ARE THERE ANY OTHER SURVEYS THAT BHC UTILIZES TO ENSURE THAT ITS OVERALL COMPENSATION IS COMPETITIVE IN COMPARISON WITH OTHER COMPANIES?

A. Yes. BHC also utilizes surveys conducted by Aon Hewitt, Mercer, the Edison Electric Institute (EEI), ECI, the EAPDIS LLC, Ed Powell, and other surveys, including several specific to wages by state. The surveys provide compensation and other data for each position by company size, revenue, and number of employees so that BHC can match each of its positions to positions in the market that are most similar in duties and most similar for the company size/revenue.

Q. HOW DO THE COMPANY'S COMPENSATION STRATEGIES COMPARE TO THE CURRENT MARKET?

A. The BHC Compensation Department reviews the pay structure annually to see how the structure and pay practices reflect the market. As of October 21, 2013, the average base pay for non-union employees of Black Hills Power was 95% of the market median, indicating Black Hills Power employees' base pay rates were lower than the market median. Compensation is considered to be competitive to the market at a range of 95% to 105% of the market median, so compensation for Black Hills Power is at the lower end of this range.

Q. DOES BHC HAVE A VARIABLE COMPENSATION COMPONENT OF ITS TOTAL COMPENSATION PHILOSOPHY?

A. Yes. The Black Hills Corporation Annual Incentive Plan (the "AIP" or the "Plan") is designed to motivate and reward employees for achieving and exceeding goals that benefit our customers and our shareholders. The AIP is designed to reward eligible employees, including both non-union and union employees of Black Hills Power, who contribute to the success of the BHC and/or their assigned Business Unit; reward employees who contribute to the quality of service provided to customers including, but not limited to, the provision of safe, reliable and affordable service; motivate work performance and behavior that supports the Corporation's financial and non-financial goals and increase the employee's understanding of the Corporation's business objectives and performance.

III. COMPANY ANNUAL INCENTIVE PLAN

Q. PLEASE DESCRIBE BHC'S ANNUAL INCENTIVE PLAN.

A. The purpose of BHC's AIP is to promote BHC's pay for performance philosophy, to provide competitive incentive opportunities that are consistent with other companies in the industry, and to focus employees on important performance objectives. The AIP is an important component of the total pay package necessary to ensure BHC is competitive with market practices for employees. In addition, the AIP directly links pay with performance, and therefore total compensation expense varies with BHC's performance on measures important to the customers, and provides a tool to align employees' interests with customer and community interests.

Q. WHO IS ELIGIBLE TO PARTICIPATE IN THE AIP?

A. All regular full-time and part-time employees, both union and non-union, who are hired and working by October 1 of the plan year are eligible to participate in the Plan for that plan year. Part-time employees who work a minimum of 20 hours per week are eligible for a pro-rata award based on their actual wages for hours worked. Pro-rata awards for the number of months actively employed at each eligibility level during the plan year will also be paid to Participants who are hired, promoted, retire or have other job changes during the year.

Q. WHAT PERFORMANCE GOALS ARE MEASURED UNDER THE AIP?

A. An eligible employee can earn an incentive award based on that employee's performance toward goals designed to achieve business unit operational performance targets. The components of the incentive award for the test year were as follows:

- An employee could qualify for up to 50% of the maximum possible award for goals tied to customer satisfaction, cost control, safety, reliability, operations efficiency, expense reductions and other operational measures;
- An employee could qualify for up to 25% of the maximum possible award for the achievement of direct business unit operating income goals, including initiatives on cost control, continuous improvement and improvements in operations efficiencies; and
- An employee could qualify for up to 25% of the maximum possible award if BHC realizes established earnings per share ("EPS") targets.

Each goal is measured independently. Goal performance that meets or exceeds the threshold level will be used to calculate the incentive award. Achievement of financial results is not a condition to award incentive for achievement of other goals. An employee can earn from 0 to 1.50 times the target percentage incentive based on achievement against each of the AIP goals. Performance below threshold results in a zero payout for the associated goal. Achievement of a goal's "target" performance results in a payout of 100% of the payment relative to that goal. There is also a Maximum payout, which means that if performance exceeds target, no more than 1.50 times the target payment will be made relative to that goal.

Q. HOW DOES THE AIP PROVIDE VALUE TO CUSTOMERS?

A. The AIP provides direct and indirect value to customers in a number of different ways. For example, AIP goals are aligned with BHC's high-level objectives and strategic framework. Business unit goals are primarily designed to improve the performance of utility operations by focusing on improvements to operational excellence, safety, reliability, and customer satisfaction. Examples of Black Hills Power's business unit goals include:

- Continuous improvement in results from customer satisfaction surveys. These results are measured each quarter.
- Service reliability metrics.
- Increase in number of completed service orders per day.
- Reduction in labor cost per service order.

- Reductions in O&M expense resulting from Continuous (Process) Improvement projects.
- Reduction in number of lost time accidents, preventable vehicle accidents, and OSHA recordable accidents.

BHC must maintain a skilled and motivated workforce in order to provide safe, reliable and affordable service and products. To do so, it is important to pay our employees at rates competitive to rates paid by similar utilities and other companies with which we compete for employees. Because the actual base salaries for Black Hills Power's employees fall somewhat below the market median levels, total compensation would be significantly less competitive without the incentive plan component. An employee's total cash earnings potential (base salary *plus* AIP incentive award) depends on both competitive base salary and on a competitive AIP incentive compensation opportunity awarded for the achievement of key operating and strategic goals.

Q. HOW WOULD AVERAGE BASE SALARIES BE AFFECTED IF AIP INCENTIVES WERE ELIMINATED?

A. If BHC did not offer employees the opportunity to earn AIP incentive compensation, BHC would need to make-up the difference by increasing base salaries in at least an equivalent amount, which would result in higher fixed costs for salaries and benefits. An alternative to variable compensation would be for BHC to raise all employees base pay to reflect the median variable compensation earnings provided by other utilities. While this would provide a competitive total compensation rate that is "fixed and measurable", it would de-link those costs with customer performance measures and increase overall costs as many of our benefits are also tied to base pay rates.

Q. DO YOU BELIEVE THAT THE AIP IS AN IMPORTANT ELEMENT OF EMPLOYEE RETENTION?

A. Yes. If BHC were to eliminate its variable pay program and did not replace that compensation with base pay, employees would be much less likely to stay with BHC because their total compensation would significantly lag what other utilities were paying for the same positions. Coupling this risk with the loss of experience that Black Hills Power will realize over the next eight years due to retirements, results in a significant and immediate business risk.

Q. ONE OF THE INCENTIVE GOALS UNDER THE AIP RELATES TO THE COMPANY'S OPERATING INCOME OR EARNINGS PER SHARE ("EPS") PERFORMANCE. DO CUSTOMERS BENEFIT FROM COMPANY EPS PERFORMANCE IN LINE WITH INCENTIVE PLAN TARGETS?

A. Yes. Earnings Per Share is an easily recognized benchmark for successful and productive companies that are meeting their customers' needs. They provide company-wide objective measures of performance that cannot reasonably be separated from customer interest. Both shareholders and customers benefit from strong EPS performance - - they are not mutually exclusive. Two primary drivers of EPS are expense management and debt costs. Customers benefit from receiving service from a company that is able to effectively manage its costs. When the Company is managing its costs, rate cases are less frequent. When a rate case is required, the requested increase is less than would otherwise be required.

Q. DO INDIVIDUAL EMPLOYEES CONTRIBUTE TO THE COMPANY'S EPS PERFORMANCE?

A. Yes. Each employee primarily contributes to the financial success of the Company through the prudent actions he or she takes to control costs, work efficiently, and drive operational excellence. By setting an EPS target, and monitoring company performance against the target throughout the year, employees receive immediate feedback regarding performance. Providing incentive compensation related to meeting financial performance drives employees to cost-conscious behavior that is beneficial to customers.

Q. HOW ELSE DO CUSTOMERS BENEFIT FROM A STRONG EPS RECORD?

A. As described in the Direct Testimony of Brian G. Iverson, Black Hills Power must maintain financial integrity to access capital at reasonable costs. A strong financial position provides the financial flexibility necessary to meet the ongoing demand for utility services. Credit ratings agencies compare quantitative measures of a company's financial performance, including EPS, to determine a company's credit ratings. These ratings have a direct impact on the cost of Company's debt, both for acquiring debt and refinancing higher cost debt, which directly impact customer rates. Through strong EPS performance, the Company is able to maintain or even improve its credit ratings, resulting in a lower cost of debt for customers. Because Company earnings are such an important consideration in rating agency evaluations of the Company, it is critical that employees receive incentives to maintain strong financial performance, which ultimately results in lower costs for customers.

IV. COMPANY LONG-TERM INCENTIVE PROGRAM

Q. PLEASE DESCRIBE BHC'S LONG-TERM INCENTIVE PROGRAM.

A. The Company provides a long-term incentive program on a limited basis to key employees who are responsible for various aspects of management and business results. These long-term incentives include restricted stock and performance share awards. Restricted stock is granted to key employees and vests ratably over a 3-year period. The purpose of the 3-year vesting period for both the restricted stock and the performance shares is to get retention of key employees.

Performance shares, if any, are based on achievement against established criteria measured over a 3-year period and are made at the conclusion of that 3-year period. The performance share component measures relative performance of BHC against other utilities - - it is about operational performance and metrics. BHC focuses on top quartile performance in all areas and performs at this level on a sustained basis. This operational excellence is recognized by the market and using performance measures to compare BHC to its peers provides focus for key employees in these areas. This operational excellence also results in lower costs to customers in very direct ways. For example, BHC's continued high performance for power plant availability is recognized by the market with higher stock performance, but impacts the customers directly through lower cost of service, high reliability, and high customer satisfaction.

Both forms of equity grants under the long-term incentive program are intended to provide participants with incentives for excellent performance, to promote teamwork and to motivate, retain and attract the services of participants who make significant contributions to the success of the company and its operational goals.

V. INDUSTRY COMPENSATION COMPARISONS

Q. DO OTHER COMPANIES IN THE UTILITY INDUSTRY USE COMPARABLE VARIABLE AND LONG-TERM COMPENSATION MECHANISMS?

A. Yes. Other utilities do provide incentive or variable compensation as part of their compensation packages, as do companies in other industries. Other utilities also provide key employees with long-term incentives designed to retain these key employees and to motivate them to achieve operational and strategic goals. Without similar annual and long-term plans, BHC's total compensation package would not be competitive with other utilities and BHC would be at risk for retention of its key employees.

Q. ARE YOU AWARE OF ANY STUDIES THAT SUPPORT THIS CONCLUSION?

A. Yes. Aon Hewitt Associates, an international business consulting firm that specializes in compensation issues, conducted a survey of broad-based variable pay plans in 2013 titled "Variable Compensation Measurement (VCM) Report – U.S. Edition," which includes 125 companies, including 25 energy / utility companies. Results from the survey indicate the following:

- 90% of participating companies offered at least one broad-based variable compensation plan covering 99% of total U.S. employees, an increase from 89% in 2007 and from 80% in 2002 as companies continue to turn to variable pay as a means to attract, retain and award performance. All energy / utility companies offer at least one broad-based variable incentive plan and all cover 100% of their employees.
- 74% of the participating companies in the survey have an annual incentive program with a plan design similar to BHC's AIP, where awards are based on the combined achievement of Company financial and business unit operating performance.
- 88% of the participating companies reported the benefits realized from their variable pay plan and the improved business results outweighed the cost.
- Notable outcomes reported by companies with a variable pay plan similar to the AIP include reduced costs, increased productivity, increased quality, increased customer satisfaction, and increased employee morale.

Other surveys published in 2012-2013 include:

- Mercer: 93% of employers provide short-term incentive or variable pay plans, an increase from 78% in 2004.

- World at Work: 84% of employers provide short-term incentive or variable pay plans, an increase from 77% in 2004. Of those providing a short-term incentive plan, 98% of hourly employees (average payout was 5%) and 100% of salaried employees (average payout was 12%) are eligible under the plan.
- Buck Consulting: 87% of utilities in the survey provide a short-term incentive plan to all employees.
- Kenexa: 88.5% of energy and utility companies in the survey provide a short-term incentive plan to all employees.

Q. HOW DOES BHC MAKE IMPROVEMENTS TO ITS AIP?

A. Through its annual strategic and operational planning process, BHC routinely evaluates the effectiveness of the plan in meeting its goals. These goals are modified and continually refined to drive continued operational excellence and performance improvements. BHC also continuously evaluates the AIP design to ensure that it remains competitive and comparable to other utilities.

VI. COMPANY RECOVERY OF EMPLOYEE COMPENSATION EXPENSES

Q. SHOULD THE COMPENSATION MERIT INCREASE BE APPROVED?

A. Yes. Recovering the actual amount of employee compensation expense is necessary to attract and retain the high quality of employees that are needed to serve the customers of Black Hills Power. Under existing economic conditions, independent surveys reflected that more than 97% of US-based companies will award merit pay increases during 2014, with an average budget of 3% to 4%. Non-union employee pay changes are effective each March, with the most recent increase effective March 4, 2013 and the next scheduled merit increase to be effective March 3, 2014. The company has a non-union merit increase budget for 2014 of 3.50%. The union salary increases for the period April 1, 2013 through March 30, 2014 range from 3.0% to 3.5% by position and the wage increase will be 3.25% effective April 1, 2014. Increases in employee compensation are known and measurable, and these increases in employee compensation are supported by extensive reviews of competitive market data.

Without merit increases, BHC would further lag the median pay for these positions, significantly increasing retention and performance risk, and the company will incur higher costs for turnover and related issues. A summary of independent surveys regarding merit pay follows:

- Mercer: The survey of 634 employers reflects that energy and utility employers plan to provide merit increases to employees in 2014, with an average budgeted increase ranging from 3.0% to 4.0%.
- Aon Hewitt: The 2013-2014 survey of 1,096 employers reflects planned 2014 merit increases, with an average budget of 3.1%. The energy and utility employers in the survey reflect a merit budget average of 3.7%.
- Towers Watson: The 2013-2014 survey of 633 employers reflects planned 2014 merit increases, with an average budget of 3.1%. This survey does not reflect utility specific information.

- World at Work: The 2013-2014 survey of 1,834 employers reflects a 3.1% merit increase budget average for 2014 across all industries. The average merit increase budgets for energy and utility companies average up to 4.1%.

Simply put, the merit increases and the union wage increases will be incurred, and the overall compensation to Black Hills Power employees is fair and competitive as tested against prevailing market comparisons.

Q. SHOULD THE COMPENSATION INCREASE BE APPROVED FOR UNION EMPLOYEES?

A. Recovering the actual amount of employee compensation expense is necessary – as described above – to attract and retain the high quality of employees that are needed to serve the customers of Black Hills Power.

The ratified contract between Black Hills Power and the IBEW Local 1250 Local Bargaining Unit requires an increase in union employee compensation of 3.0% to 3.5% depending on job classification effective April 1, 2013; and an increase of 3.25% effective April 1, 2014. Black Hills Power's union employees also participate in the AIP under the terms of the contract. Accordingly, the April 1, 2014 rate increase of 3.25% and AIP compensation for union employees is representative of the amount that Black Hills Power will be obligated to pay while its rates will be in effect. Black Hills Power's union employee compensation adjustment qualifies as a known and measurable change over the four-year contract.

VII. COMPANY BENEFITS AND PERIODIC REVIEW

Q. PLEASE DESCRIBE THE BENEFIT PLANS THAT BHC PROVIDES TO ITS BLACK HILLS POWER EMPLOYEES?

A. BHC offers a combination of company-provided and voluntary benefits. Employees are enrolled in certain company-provided benefits automatically and BHC pays the costs (for example, short-term and long-term disability benefits). Employees choose whether or not to participate in the voluntary benefits and they pay a portion or all of the costs. These company-provided and voluntary benefit programs consist of: (1) medical, dental and vision plans, (2) flexible spending accounts, (3) life insurance and accidental death and dismemberment insurance, (4) paid time off, (5) retirement, and (6) other benefits including educational assistance, holidays and other time away from work, business travel accident insurance, rewards & recognition and wellness programs.

Q. WHAT BENCHMARKING HAS BEEN CONDUCTED TO EVALUATE COST/PERFORMANCE LEVELS?

A. BHC solicits a number of independent reviews from external organizations and consulting firms such as Towers Watson, Aon Hewitt, Mercer, etc. These reviews cover a wide range of compensation and benefit program designs and costs including compensation and benefit programs, HR function administrative expenses, and market data for positions. BHC compares its benefit programs and costs with companies from the utility sector and from general industry to ensure the company can attract and retain employees with the necessary skills. BHC utilizes multiple nationally recognized third-party surveys and also conducts customized surveys where appropriate and necessary. These benchmarking surveys allow BHC to evaluate the competitiveness and efficiencies of its benefit programs and costs compared to other companies in the market. If a program does not meet performance, cost or efficiency expectations, it is reviewed to determine the root cause and the options or alternatives available. BHC closely monitors market practices and benchmark data for costs to maintain competitive and cost effective programs.

Q. WHAT TYPE OF OVERSIGHT IS IN PLACE TO ENSURE THAT BHC'S COMPENSATION AND BENEFIT PROGRAMS ARE THOSE THAT ARE MOST BENEFICIAL FOR THE SUPPORT OF THE OPERATING COMPANIES' UTILITY SERVICE?

A. The BHC Human Resources Department, in partnership with the business unit leaders and company management, develop annual budgets and long-range plans (5 years), including compensation, benefit and other programs supporting the business' goals and objectives. HR and key operating personnel manage these budgets and review all programs for effectiveness, cost and any proposed modifications. All costs are modeled to determine impacts to cost and are benchmarked against the market parameters to ensure competitiveness, cost effectiveness, and reasonableness.

Q. ARE YOU AWARE OF OTHER STATE COMMISSIONS THAT HAVE APPROVED THE EMPLOYEE COMPENSATION AND BENEFIT STRUCTURE PROPOSED IN THIS PROCEEDING?

A. Yes. Through rate case settlements and contested proceedings, commissions in Nebraska, Iowa, Wyoming and Colorado in both gas and electric rate cases have approved this employee compensation and benefit structure. BHC places emphasis on maintaining a common employee compensation structure and program. The same is true for its proposal related to its employees living in or supporting our Black Hills Power customers.

VIII. ADJUSTMENTS DUE TO SUSPENSION OF CERTAIN OPERATIONS

Q. HAS BLACK HILLS POWER SUSPENDED OPERATIONS AT ANY OF ITS FACILITIES?

A. Yes, Black Hills Power placed its Osage and Ben French facilities into economic shutdown. Black Hills Power has suspended operations at its Neil Simpson I facility. As indicated in the testimony of both Vance Crocker and Mark Lux, these three facilities will be decommissioned as a result of the EPA's National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial and Institutional Boilers.

Q. WHAT ADJUSTMENTS WERE MADE RELATED TO PERSONNEL DUE TO THE SUSPENSION OF OPERATIONS AT THESE FACILITIES?

A. Adjustments have not been made for the employees that were employed at Osage and Ben French when those facilities were placed into economic shutdown. The affected employees retired, took alternate positions with the Company, or left the Company. Black Hills Power has had a labor reduction due to the suspension of operations at Neil Simpson I. However, these employees were retained by Black Hills Power as part of its strategic workforce planning.

More specifically the Neil Simpson I employees have been retained and are assigning part of their time to the common Neil Simpson complex facilities. These employees also direct charge other specific units, such as Cheyenne Light and Black Hills Wyoming, and common facilities for work performed at those facilities. Retention of these critical skills is necessary to ensure the continued provision of safe, reliable and cost-effective service to customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Direct Testimony
Jon Thurber

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. EL14-___

March 31, 2014

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Exhibits

None

I. INTRODUCTION & QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jon Thurber, 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota 57701.

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

A. I am employed by Black Hills Utilities Holdings, Inc. ("Utility Holdings"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"). I am Manager of Regulatory Affairs for Black Hills Power, Inc. ("Black Hills Power" or the "Company"). I am responsible for leading all aspects of the regulatory process for Black Hills Power.

Q. FOR WHOM ARE YOU TESTIFYING ON BEHALF TODAY?

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

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I graduated summa cum laude from the University of Wisconsin – Stevens Point, with a Bachelors of Science Degree in Managerial Accounting, Computer Information Systems, Business Administration and Mathematics. My work experience includes working for the South Dakota Public Utilities Commission ("Commission") as a Utility Analyst from July 2008 through March 2013. At the South Dakota PUC, my responsibilities included analyzing and testifying on ratemaking matters arising in rate proceedings involving electric and gas utilities. I began my career with Utility Holdings in April 2013 as Manager of Rates. In

February of 2014, I accepted the position of Manager of Regulatory Affairs for Black Hills Power.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes.

II. <u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to present and explain the Revenue Requirement Model (the "Model") that supports this rate case filing. The Model is presented in Volume 1 of Black Hills Power's Application, as Section 4, Statements A through R and supporting Schedules, and with Workpapers included as Section 5. In my testimony, I describe the adjustments to certain utility costs, and I support the revenue requirement.

III. <u>REVENUE REQUIREMENT MODEL OVERVIEW</u>

Q. PLEASE DESCRIBE YOUR ROLE IN PREPARING THE MODEL.

A. My role was to directly supervise the preparation of the per books and pro forma information, including the Statements and supporting Schedules and Workpapers.

Q. IS THE REVENUE REQUIREMENT MODEL FILED IN THIS CASE CONSISTENT WITH THE MODEL USED IN BLACK HILLS POWER'S 2012 RATE CASE?

A. Yes, the models are consistent.

Q. WHAT HAS BLACK HILLS POWER USED FOR A TEST YEAR IN THIS FILING?

A. Black Hills Power is utilizing a twelve month test year based on historical data, ending September 30, 2013, as adjusted with known and measurable changes.

Q. WHAT STATEMENTS HAVE YOU INCLUDED IN THIS FILING?

A. The following is a list of the Statements provided in the Application:

A. Balance Sheet
B. Income Statement
C. Statement of Retained Earnings
D. Utility Plant in Service
E. Accumulated Depreciation
F. Working Capital
G. Cost of Capital
H. Operation and Maintenance Expense
I. Operating Revenues
J. Depreciation Expense
K. Income Taxes
L. Taxes Other Than Income
M. Overall Revenue Requirement
N. Allocated Cost of Service by Jurisdiction
O. Allocated Cost of Service by SD Customer Class
P. Energy Cost Adjustment Factors

Q. Description of Utility Operations

R. Coal Supply Pricing Methodology

Q. WHAT SCHEDULES HAVE BEEN INCLUDED IN THE FILING?

A. Schedules have been included, where applicable, to provide supporting documentation and calculations for the Statements listed above. For example, Schedules H-1 through H-21 support Statement H, Operation and Maintenance Expense. These Schedules detail the expense adjustments that have been made and summarized in Statement H.

Q. HAVE WORKPAPERS BEEN INCLUDED IN THE FILING?

A. Yes, Workpapers have been included in Volume 1 as supporting documentation for the Statements listed above. For example, Workpaper 1 supports the energy allocation incorporated in Statement N, Allocated Cost of Service by Jurisdiction.

Q. PLEASE EXPLAIN HOW THE REVENUE REQUIREMENT WAS DEVELOPED.

A. The starting point to determine the revenue requirement is the per books financial statements for the test year, kept and recorded in the normal course of business, in compliance with FERC rules and regulations. Adjustments for known and measurable items were then made to the per books financial statements to determine the pro forma costs and revenue requirement.

Q. WHAT ADJUSTMENTS WILL BE MADE TO THE TEST YEAR?

A. Black Hills Power is incorporating pro forma adjustments to the test year that are known and measurable and relate to investments that will be used and useful prior to new rates going into effect. Known and measurable adjustments to the per books financial statements include: 1) additional rate base that will be used to serve customers at the time the new rates go into effect including, but not limited to, the addition of the Cheyenne Prairie Generating Station ("CPGS"); and 2) adjusting revenues and expenses for operational changes.

Q. PLEASE SUMMARIZE THE SIGNIFICANT ADJUSTMENTS THAT HAVE BEEN MADE TO BLACK HILLS POWER'S MODEL.

A. Adjustments have been made for rate base in Statements D, E, and F, and on Schedules M-1 and M-2. Expense adjustments have been included in Statements H, J, K, and L. Revenue adjustments are included in Statement I. The most significant known and measurable adjustment relates to CPGS. The adjustment includes additions to rate base, as well as changes to the cost of service expenses to reflect projected increases in operation and maintenance costs for a full year of operations.

IV. <u>RATE BASE</u>

Q. PLEASE DESCRIBE RATE BASE.

A. Rate base is the value established by a regulatory authority, upon which a utility is allowed to earn a specified rate of return as shown on Statement M. Rate base begins with the thirteen month average amount of all fixed asset accounts for Black Hills Power as of September 30, 2013, as shown on Statement D, Page 2, reduced by accumulated depreciation as shown on Statement E, Page 1. Additional rate base is then added to reflect expected capital additions from

September 30, 2013, through the effective date of this rate case as shown on Statement D, Page 2. Additional depreciation expense is also included, along with a corresponding increase in accumulated depreciation, thereby decreasing rate base. Rate base also includes a component of working capital as shown on Statement F. The final component of rate base is the other rate base reductions, such as deferred federal income taxes, as those reductions relate to the timing difference of book depreciation and tax depreciation expense. These amounts can be found on Schedules M-1 and M-2.

Q. ARE YOU REQUESTING CONSTRUCTION WORK IN PROGRESS AS PART OF RATE BASE?

A. No. The only plant investment in rate base will be that which is used and useful prior to rates going into effect.

A. PLANT IN SERVICE

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR CPGS.

A. Schedule D-11 shows the capital costs associated with CPGS. The adjustment for CPGS construction costs was prepared using the actual cost incurred as of December 31, 2013, together with the projected remaining costs to complete the project. Since CPGS is jointly owned by Black Hills Power and its sister company Cheyenne Light, Fuel and Power Company ("Cheyenne Light"), the adjustment only reflects Black Hills Power's ownership percentage. A more detailed explanation of these costs is included in Mark Lux's testimony.

Q. IS THE COMPANY PROPOSING ANY ADDITIONAL ADJUSTMENTS FOR PLANT ADDITIONS?

A. Yes, there are other known and measurable adjustments for plant investments that will be used and useful prior to rates going into effect. Schedule D-10 provides a detailed list of production, sub-transmission, distribution, and general plant additions that will serve customers prior to October 1, 2014. The major plant additions are further discussed in the testimony of Mark Lux and Mike Fredrich.

Q. PLEASE EXPLAIN WHY THE COMPANY IS REQUESTING COST RECOVERY OF PLANT INVESTMENTS THAT WILL BE PLACED IN-SERVICE PRIOR TO OCTOBER 1, 2014.

A. The Commission has historically issued its final decision within six to twelve months from the date the rate case was filed. The Company assumes that this docket will be processed within approximately six months, and is requesting cost recovery of capital projects that are expected to be placed in service when final rates go into effect. If this docket takes longer than six months to process, the Company requests the opportunity to supplement this filing with additional capital projects that are used and useful prior to final rates going into effect.

Q. IS THE COMPANY REFLECTING ANY ADJUSTMENTS FOR PLANT RETIREMENTS?

A. Yes. The Ben French, Neil Simpson I, and Osage power plants were retired on or before March 21, 2014, to comply with the Environmental Protection Agency ("EPA") Area Source Rules. The facilities will no longer be providing power or capacity for customers when rates go into effect from this proceeding, and should not be included in plant in service. The plant adjustment is reflected on Statement D, page 2, and the corresponding rate base adjustments are made to accumulated depreciation on Statement E, page 1, working capital on Schedule F-1, and accumulated deferred income taxes on Schedule M-2. The net book value and associated inventory for the three units were transferred to a regulatory asset as reflected in Schedule J-2.

B. TRANSMISSION FACILITY ADJUSTMENT CLAUSE

Q. IS THE COMPANY PROPOSING TO SHIFT COST RECOVERY OF SUB-TRANSMISSION ASSETS FROM THE TRANSMISSION FACILITY ADJUSTMENT ("TFA") RIDER TO BASE RATES?

A. Yes. Black Hills Power is requesting to move from the TFA to base rates all sub-transmission assets that are placed in-service prior to final rates going into effect. In Docket EL14-013, the Company requested cost recovery through the TFA of two 69 kV line rebuild projects, Custer to Hot Springs and Lookout to Sundance Hill, that are expected to be placed in-service prior to September 30, 2014. The recovery of these two projects and related expenses are included in the Company's base rate request in this docket.

Q. WHEN WILL THE TFA RATE BE ADJUSTED TO REFLECT THIS SHIFT IN COST RECOVERY?

A. The Company will make its annual TFA filing by February 15, 2015, to reflect the Commission's decision regarding these assets.

C. WORKING CAPITAL

Q. HOW WAS WORKING CAPITAL CALCULATED AND INCLUDED IN RATE BASE?

A. Working Capital is shown on Statement F. The first component is cash working capital as determined by a lead/lag study. The other components are materials and supplies and prepaid expenses using a thirteen month average on balances as of September 30, 2013, with known and measurable adjustments. The final adjusted Working Capital balance of $17,824,269, as shown on Statement F, is included as part of rate base.

Q. DESCRIBE HOW THE CASH WORKING CAPITAL AMOUNT WAS DETERMINED.

A. The Company prepared a per books and an as adjusted Cash Working Capital ("CWC") amount for this rate case. The per books CWC is located on Schedule F-3, page 1 and the as adjusted CWC is on Schedule F-3, page 2. The as adjusted CWC amount is used as a component of rate base. The per books and as adjusted CWC amounts were determined by preparing a Lead/Lag Study.

Q. HOW DOES A LEAD/LAG STUDY MEASURE THE AMOUNT OF CASH REQUIRED FOR OPERATING EXPENSE?

A. A lead/lag study measures the difference between: (1) the time a service is rendered and billed until the time revenues for that service are received ("lag") and (2) the time that services, materials, etc., are obtained/used and the time expenditures for those services are made ("lead"). The applicable lead period for each major category of expense is compared to the revenue lag period. The difference between those periods, expressed in days, multiplied by the average daily operating expense, yields the amount of CWC requirement.

Q. HOW WAS THE EXPENSE LEAD DAYS CALCULATED ON SCHEDULE F-3?

A. The expense lead days are the actual days between when a service is received and when payment is made for those services. To determine the expense lead days for each expense category, Black Hills Power reviewed a sample of invoices paid from that category and determined the average number of days it took to pay each of those invoices. The expense per day is calculated by taking the total expense per category divided by the number of days in the year. Finally, that expense per day for each category is multiplied by the expense lead days for that category to determine the expense dollar days for each category. Line 41 of Schedule F-3, page 2 contains the combined total of the expense dollar days and the combined total of the expense per day for all the expense categories. On Schedule F-3, the total in column (d) was divided by the total in column (b), resulting in the expense lead days of 43.34, which is shown on line 44.

Q. CAN YOU DESCRIBE HOW THE REVENUE LAG DAYS WERE CALCULATED?

A. The midpoint of service for each revenue month during the test year was first determined by dividing the total days of the year by 12 and then by 2. Then the amount of lag days between when the meter is read and when the customer is billed, was determined by using the Company's billing system and calculating that amount on a monthly basis. The monthly results are then averaged to arrive at an annual average. Next, the average number of days between billing and receipt of payment was determined. This was done by using the Company's billing system, calculating that amount on a monthly basis and then averaging the monthly results to arrive at an annual average. Finally, the sum of the results discussed above were added together to determine the total revenue lag days of 33.98, as shown on Schedule F-3, line 43.

Q. WHAT WAS THE RESULT OF THE LEAD/LAG STUDY?

A. The results of the lead/lag study demonstrate that, in aggregate, customers have supplied funds to the utility to pay for expenses prior to the utility paying for the same expenses. As a result, a rate base reduction was included in the determination of total rate base.

Q. WHAT AMOUNT OF CASH WORKING CAPITAL WAS DETERMINED?

A. The final cash working capital adjusted balance developed from the lead/lag study is ($5,839,251). The adjusted balance of cash working capital is used as a component of rate base.

Q. EXPLAIN THE KNOWN AND MEASURABLE ADJUSTMENT MADE TO FUEL STOCKS.

A. The adjustment reflects a new coal stockpile at the Neil Simpson Complex associated with the Coal Redundancy project. This stockpile provides approximately 5 to 7 days of coal for generation in the event of a major malfunction with mining operations. This inventory should allow adequate time to implement back up plans to ensure the continuous delivery of coal. These costs are supported through the testimony of Mark Lux.

Q. EXPLAIN THE KNOWN AND MEASURABLE ADJUSTMENTS MADE TO MATERIALS AND SUPPLIES.

A. Several adjustments were made to materials and supplies as summarized on Statement F, line 5. The individual adjustments are itemized on Schedule F-1 and Schedule F-4.

Schedule F-1, Row 29: Row 29 reflects a spare transformer rebuild that was received in November 2013. This spare transformer is for the Neil Simpson II power plant. In case of a transformer failure, the spare transformer will allow more timely restoration of service.

Schedule F-1, Row 30: Row 30 reflects spare fan motors for the coal units at the Neil Simpson Complex. The motors are critical to the operation of the units that have no back-up or redundancy. A typical motor failure would result in a major outage of many weeks to months. The fan motors are uniquely designed for each generation unit, so there is no "off the shelf" availability from manufacturers. The lead time for ordering a replacement motor is approximately 36 weeks.

Schedule F-1, Rows 32 – 34: Rows 32 through 34 remove the inventory from the test year associated with the Ben French, Osage, and Neil Simpson I power plants. These plants were retired on or before March 21, 2014, as the most cost effective plan for EPA compliance, and the associated inventory will no longer be needed for the operation of the plants. The cost of the inventory at these plants will be transferred to the regulatory asset established for decommissioning these units.

Schedule F-4: This schedule reflects Black Hills Power's ownership percentage of critical spare parts needed at CPGS to reduce the amount of lost production time. The plant operations department provided the current market prices for each item of equipment. These costs are supported through the testimony of Mark Lux.

D. OTHER RATE BASE REDUCTIONS

Q. WHAT OTHER REDUCTIONS TO RATE BASE WERE MADE?

A. Deferred federal income taxes related primarily to accelerated depreciation, cash received for customer deposits, advances for construction, and also pension related costs are included as reductions to rate base, as shown on Schedule M-1 and M-2.

Q. ARE THESE OTHER REDUCTIONS TO RATE BASE CONSISTENT WITH THE COMPANY'S LAST RATE CASE?

A. Yes, we used a consistent approach and accounts to reduce rate base.

Q. WHAT OTHER ADJUSTMENTS DID YOU MAKE TO REDUCE RATE BASE?

A. As shown on Statement E page 1, the Company also made an adjustment to reduce rate base for additional accumulated depreciation expense. This adjustment increases accumulated depreciation to reflect one-half of the annual depreciation expense associated with new assets summarized on Statement D, Page 2 and the new depreciation rates on Statement J.

Q. WERE PRO FORMA ADJUSTMENTS MADE TO OTHER RATE BASE REDUCTIONS?

A. Yes. Schedule M-1 provides for an adjustment that reflects the thirteen month average on balances as of September 30, 2013, for Other Regulatory Assets (182), Deferred Income Tax Asset (190), Customer Advances for Construction (252), Other Regulatory Liabilities (253 and 254), Deferred Tax – Accelerated Depreciation (282), and Deferred Income Tax Liability (283) accounts. Consistent with prior rate cases, an adjustment was made for deferred taxes related to the accelerated depreciation for the pro forma capital additions to be placed in service prior to the effective date of the new rates resulting from this rate case. The Company has once again elected bonus depreciation rates for assets that were eligible. This calculation is shown on Schedule M-2 and includes an offset for a Net Operating Loss ("NOL") adjustment. This NOL is created since there is not enough taxable income to use the entire bonus depreciation. In other words, the Company is not able to receive the cash benefit for the bonus depreciation tax deduction; therefore a tax asset is created for this timing difference.

E. <u>DECOMMISSIONING AND WINTER STORM ATLAS REGULATORY ASSETS</u>

Q. DID THE COMMISSION ISSUE AN ACCOUNTING ORDER TO ESTABLISH REGULATORY ASSETS FOR THE WINTER STORM ATLAS COSTS AND COSTS ASSOCIATED WITH DECOMMISSIONING THE NEIL SIMPSON I, OSAGE, AND BEN FRENCH POWER PLANTS?

A. Yes. On January 9, 2014, in Docket EL 13-036, the Commission issued an Order Approving Deferred Accounting For Storm Damage Costs (associated with Winter Storm Atlas) and Transfer of Remaining Plant Balance for soon to be Decommissioned Plants to a Regulatory.

Q. EXPLAIN THE RATE BASE ADJUSTMENTS FOR WINTER STORM ATLAS AND DECOMMISSIONING REGULATORY ASSET.

A. The rate base adjustments for the decommissioning and Winter Storm Atlas regulatory assets are reflected on Schedule J-2 and J-3, respectively. The adjustments reflect the unamortized balance to be included in rate base until fully amortized. An adjustment to the operating income statement is being made to recognize a full year of amortization expense. Therefore, the amount of rate base being included in the test year is reduced by the accumulated amortization for a full year.

V. ADJUSTMENTS TO THE OPERATING EXPENSES

Q. PLEASE DEFINE OPERATING EXPENSES.

A. Total operating expenses are costs incurred by the Company in order to supply electricity to the customers of Black Hills Power. In the development of the revenue requirement, these operating costs are passed on to customers dollar for dollar; that is, without Black Hills Power earning any net income on those expenses. Expenses are reflected in the following statements:

1) Statement H shows the operating and maintenance expenses in detail by FERC account.

2) Statement J is the calculation of depreciation and amortization expense.

3) Statement K shows the calculation of federal income tax expense.

4) Statement L calculates taxes other than federal income taxes - such as federal payroll taxes.

5) All of the Statements are summarized on Statement M to show the per books and the pro forma rate of return.

Q. PLEASE EXPLAIN THE ADJUSTMENTS FOR THE EXPENSES ON STATEMENT H.

A. Several adjustments were made to the expenses as shown on Statement H, columns (b) – (s). Statement H starts with the per books information for the twelve months ending September 30, 2013, by FERC account number. Each adjustment has a column on this page and a supporting Schedule to show how the adjustment was determined.

Adjustment (b): The adjustment of $1,688,744 on Schedule H-1 represents the actual and projected wage increases and changes in personnel. These amounts are calculated using an average of union negotiated wage increases and expected non-union wage increases, together with the costs associated with open vacancies and additional employees needed for operations. The labor costs associated with Neil Simpson I personnel who will have part of their time charged to power plants not owned by Black Hills Power at the Neil Simpson Complex have been removed from the test year. Please refer to the testimony of Laura A. Patterson and Jennifer Landis for a further description of the compensation program for Black Hills Power employees, FutureTrack Workforce Development Program, and personnel changes at Ben French, Osage, and Neil Simpson I.

Adjustment (c): Schedule H-5 contains the corporate costs charged to Black Hills Power from Utility Holdings for the twelve months ending September 30, 2013. This amount is then adjusted to reflect the allocation of Utility Holdings costs to Black Hills Power after CPGS is placed in service on October 1, 2014. The adjustment is an increase of $2,303,019 to the operating expenses. These expenses are a combination of direct and indirect charges without any additional fees. The allocation methods for indirect charges are described in the Utility Holdings Cost Allocation Manual, which is included as an Exhibit to the direct testimony of Christopher J. Kilpatrick.

Adjustment (d): Schedule H-6 represents the cost increases to provide retiree healthcare, medical costs for employees, pension plan premiums, and the employer portion of the 401(k). The adjusted FAS 87 pension plan expense reflects the most recent five year average. The annual pension expense has ranged between $976,122 and $3,251,072 from 2010 through 2014, and the annual percent change has ranged between a 64% decrease and a 79% increase. The Company proposes to normalize pension expenses because these expenses fluctuate widely from year to year. These pro forma amounts are compared to the test year expense, and the difference is an increase to operating expenses of $334,319.

Adjustment (e): Schedule H-7 provides the calculation to normalize bad debt expense using a three year historical period. The average net write-offs during that three year period was then divided by the average billed revenues to determine the average uncollectable expense for the Company. This average rate was then applied to the projected new revenue amount to determine the expected bad debt expense. This was compared to the actual test year amount and a decrease to operating expenses of $20,937 was then included as an adjustment.

Adjustment (f): Schedule H-8 provides for Black Hills Power's costs related to generation dispatch and scheduling. These costs are in accordance with the Generation Dispatch and Energy Agreement effective July 1, 2012, that has been filed with the FERC. This agreement allocates costs to the parties contracting for services based on the total capacity of each company. Based on the current Generation Dispatch and Scheduling costs, the expense adjustment is $107,964.

Adjustment (g): Schedule H-9 removes all the costs that are collected through the Energy Cost Adjustment ("ECA") from the test year. The Commission approved separating the ECA costs from base rates in Black Hills Power's last rate case, Docket EL12-061. The adjustment decreases operating expenses by $51,252,370.

Adjustment (h): Schedule H-10 shows Black Hills Power's pro forma adjustments for the Neil Simpson Complex Shared Facilities Agreement. Total expenses are provided along with the calculation of Black Hills Power's share of these expenses based on pooled expensed net capacity allocators. This adjustment reflects the retirement of Neil Simpson I on or before March 21, 2014. These 2014 revenue and expense amounts are compared to the per book amounts with the difference representing the adjustment.

Adjustment (i): Schedule H-11 represents the removal of costs associated with unallowable advertising. The adjustment eliminates costs associated with brand and image advertisements, and sponsorship of community organizations. The advertising included in the cost of service are those designed to promote safety, inform and educate consumers on the utility's financial services, and disseminate information on a utility's corporate affairs to its owners. The adjustment decreases operating expense by $262,517.

Adjustment (j): The adjustments in Schedule H-12 relate to Power Marketing activities of Black Hills Power. Adjustments made represent costs for energy sold by Power Marketing for marketing purposes which are not used to serve Black

Hills Power's load and thus, not included in the cost of service. The total expense that is eliminated from the test year is $28,035,682.

Adjustment (k): Schedule H-13 is a detailed listing of outside consulting costs related to this rate case and certain consulting costs associated with the 2012 rate case and phase in plan rate dockets. The Settlement Stipulation ("Stipulation") approved in Docket EL12-061 allows for the rate case costs incurred in Dockets EL12-061 and EL12-062 in excess of $261,813 to be recovered in this case. The Company proposes amortizing these costs over a three year period with the unamortized amount included in rate base.

Adjustment (l): Schedule H-14 adjusts test year vegetation management expenses to reflect the amount approved in the Stipulation in Docket EL12-061. The settlement establishes the annual vegetation management expense included in base rates, and this adjustment reduces the test year amount in accordance with the Stipulation. The adjustment reduces operating expenses by $401,420.

Adjustment (m): Schedule H-15 provides a detailed listing by FERC account of projected expense amounts to operate and maintain CPGS during a normal year. The adjustment is $2,781,469 for Black Hills Power's ownership percentage of CPGS. This adjustment is covered in more detail in the testimony of Mark Lux.

Adjustment (n): Schedule H-16 reflects the removal of severance expense during the test year for Ben French plant employees. The employee severance expense associated with the Ben French plant reflects a non-recurring event that needs to be removed from the test year to emulate normal, ongoing conditions. The total expenses eliminated were $180,861.

Adjustment (o): Schedule H-17 reflects Black Hills Power's allocation of expenses related to the operation and maintenance of Neil Simpson Complex ("NSC") common steam facilities. The NSC common steam facility expense is allocated based on capacity at the complex and Black Hills Power is responsible for the capacity associated with Neil Simpson II and its ownership percentage of Wygen III. The allocations reflect the retirement of Neil Simpson I, and the costs are based on the 2014 amounts. This was compared to the actual test year amount and an increase to operating expenses of $324,962 was then included as an adjustment. The employee retention efforts associated with this adjustment are addressed in the testimony of Laura A. Patterson.

Adjustment (p): Schedule H-18 adjusts for the removal of operating and maintenance expenses related to the discontinuance of operations at the Ben French, Osage, and Neil Simpson I power plants. The primary contributors to the expense reduction are fuel costs, fuel transportation costs, employee benefits costs, and materials used in the operation of the plants. The test year labor costs at the three plants are adjusted in Schedule H-1. The net adjustment reduces operating expenses by $3,753,186.

Adjustment (q): Schedule H-19 reflects the annual test year expense associated with BHC's FutureTrack Workforce Development Program. For additional information on the program and the Company's ratemaking proposal, please refer to the testimony of Laura A. Patterson, Jennifer Landis, and Christopher J. Kilpatrick. The adjustment increases operating expenses by $721,861.

Adjustment (r): Schedule H-20 adjusts for Black Hills Power's LIDAR surveying project on its 69 kV transmission system. The project cost is shared with the joint owners of the transmission system, and Black Hills Power's share is amortized over five years to correspond with the expected frequency of the survey. The Company requests the unamortized amount be included in rate base. The LIDAR surveying project is further discussed in the testimony of Mike Fredrich. The adjustment increases operating expenses by $136,920.

Adjustment (s): Schedule H-21 reflects the cost reductions as a result of Black Hills Power's customer service model changes. Black Hills Power completed a thorough review of its customer service model. The study found that most customers prefer self-service options via Black Hills Power's website or other automated services. Walk-in traffic has declined 45% since 2008 and that trend is expected to continue. Customers are adopting electronic payment options which will require Black Hills Power to better align its resource to provide support for these business channels. As a result, the Belle Fourche and Newell customer and electric operation services will be consolidated and moved to Spearfish and Sturgis, respectively. The new customer service strategy will allow Black Hills Power to provide better service at a lower cost to customers. The adjustment removes the salaries and benefits associated with three customer service representatives from the test year, and also eliminates the Belle Fourche and Newell facility costs. The net effect reduces operating expenses by $215,934.

Q. PLEASE EXPLAIN HOW THE EXPENSES ASSOCIATED WITH THE TRANSMISSION FACILITIES THAT CONNECT CPGS TO CHEYENNE LIGHT'S 115 kV SYSTEM ARE INCORPORATED IN THE COST OF SERVICE.

A. The CPGS transmission facilities are owned by Cheyenne Light, and Black Hills Power will be a transmission customer. The transmission expense will be based on the revenue requirement associated with the CPGS transmission assets and allocated to Black Hills Power to reflect its ownership percentage of CPGS. The expense will be recorded to FERC Account 565 and recovered from customers through the Energy Cost Adjustment.

VI. ADDITIONAL CHANGES TO THE OPERATING EXPENSES

Q. WHAT ADDITIONAL ADJUSTMENTS DID YOU MAKE TO THE OPERATING EXPENSES?

A. The depreciation expense was adjusted, as shown on Statement J, to account for the new depreciation rates as established in the depreciation study completed by Gannett Fleming in November 2013. We also calculated the depreciation expense for CPGS and other subsequent plant additions for a full year of operation. The retirements of the Ben French, Neil Simpson I, and Osage power plants are reflected by removing each plant's test year depreciation expense from the cost of service. The net result of these adjustments is an increase to depreciation expense of $3,584,757. The depreciation study is discussed in the testimony of John J. Spanos and the study is provided as Exhibit JJS-2.

Q. HOW ARE THE DEPRECIATION ADJUSTMENTS CALCULATED ON STATEMENT J?

A. The depreciation adjustment is calculated by using the new depreciation rates, as determined by our depreciation study, multiplied by the adjusted plant in service. The adjusted expense is then compared to the per books amount for the test year and the difference is recorded on Statement M as the adjusted depreciation expense and an increase in accumulated depreciation.

Q. EXPLAIN THE ADJUSTMENT FOR THE AMORTIZATION OF THE DECOMMISSIONING REGULATORY ASSET.

A. Black Hills Power is proposing to amortize the costs associated with the retirement and decommissioning of Neil Simpson I, Ben French, and Osage over five years. Schedule J-2 provides the calculation of the $3,472,714 increase to amortization expense. Please refer to the testimony of Mark Lux and Christopher J. Kilpatrick for a further description of the decommissioning costs and associated amortization.

Q. EXPLAIN THE ADJUSTMENT FOR THE AMORTIZATION OF THE WINTER STORM ATLAS REGULATORY ASSET.

A. Please refer to Vance Crocker's testimony for a description of the Winter Storm Atlas and line inspection costs. The Winter Storm Atlas damage costs include actual expenses through December 31, 2013, and estimated costs through the end of February 2014. The line inspection costs include contract labor costs for the inspection and an estimate for repair costs. Since the need for a system wide line inspection is driven by Winter Storm Atlas, the Company proposes to include the line inspection costs in the Winter Storm Atlas amortization. Black Hills Power is proposing to amortize these costs over five years. Schedule J-3 provides the calculation of the $827,702 increase to amortization expense.

Q. PLEASE EXPLAIN THE REMAINING CHANGES TO OPERATING EXPENSES.

A. On Statement L, additional payroll taxes were calculated based on the known and measurable adjustments described on Schedule H-1. The net payroll change was multiplied by the federal and state payroll tax rates to determine the adjustment of $22,257 to payroll taxes as shown on Schedule L-1.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO THE SOUTH DAKOTA PUC TAX.

A. The adjustment is based on the South Dakota pro forma retail revenue adjustments and the additional revenue requirement for South Dakota, multiplied by the gross receipts tax, resulting in an additional cost shown on Statement L.

Q. HOW IS THE FEDERAL INCOME TAX CALCULATED?

A. Federal income taxes are calculated based on the adjusted rate base amount on Statement M and Statement G debt and equity ratios. As shown on Statement K, the adjusted operating income before tax amount from Statement M, column (e), is then reduced by the adjusted interest expense as provided on Statement K, page 3.

This taxable income is multiplied by the federal income tax rate. This amount is adjusted for the permanent tax differences found on Statement K, Page 1, line 16, and tax additions and deductions found on Statement K, Page 2, lines 58 through 67, for the adjusted federal income tax expense.

VII. ADJUSTMENTS TO THE OPERATING REVENUES

Q. WHERE DO YOU GET THE PER BOOKS REVENUE ON STATEMENT I, PAGE 1?

A. The per books revenue is from the billing system for the customers of Black Hills Power for the test year ended September 30, 2013.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE TO SOUTH DAKOTA RETAIL REVENUE?

A. There are four adjustments to South Dakota retail revenue. First, the Phase In Plan Rate Rider revenue is adjusted as reflected on Schedule I-2 and discussed in Christopher J. Kilpatrick's testimony. Second, residential retail sales were affected by weather. Therefore, it was necessary to normalize sales to reflect revenue based on normal weather. Third, an adjustment is made to annualize the rate increase in Docket EL12-061 that was effective during the test period. The annualization properly calculates pro forma revenues as if the rates had been in effect for the entire test period. Please refer to the testimony of Charles Gray for further discussion on the weather normalization adjustment and the Docket EL12-061 rate annualization adjustment. Fourth, revenue associated with the ECA was removed from retail revenues as reflected on Statement I, Page 4. This relates to the matching principle as delivered energy costs were also eliminated in Schedule H-9.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO OTHER NON-FIRM REVENUE ON STATEMENT I, PAGE 1.

A. The other non-firm revenue adjustment represents the removal of revenue associated with Power Marketing. The removal of expenses associated with Power Marketing is shown on Schedule H-12.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO CITY OF GILLETTE REVENUE.

A. The City of Gillette revenue was removed as it relates to replacement energy. The associated costs are included in the Power Marketing adjustment on Schedule H-12.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO RENT FROM ELECTRIC PROPERTY.

A. The revenue from rental of electric property is increased to reflect the Neil Simpson Complex Shared Facilities adjustment as shown on Schedule H-10.

VIII. <u>SUMMARY OF THE MODEL</u>

Q. WHAT IS THE REQUESTED AMOUNT OF THE SOUTH DAKOTA INCREASE IN ELECTRIC BASE RATES?

A. Black Hills Power is seeking to increase its electric base rates to recover $14,634,238 in additional annual revenues, or an increase of 9.27%. This increase is calculated based on Black Hills Power's pro forma revenue requirement using a test year of the twelve months ending September 30, 2013. This revenue requirement is based on the jurisdictional allocation prepared on Schedule N-1.

Q. DOES THE MODEL RESULT IN A JUST AND REASONABLE REVENUE REQUIREMENT?

A. Yes. The Model uses the per books financial statements for the test year ending September 30, 2013, which contains known and measurable adjustments. The effect is a straight-forward application supporting the requested increase in base rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Direct Testimony and Exhibits
Christopher J. Kilpatrick

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. EL14-___

March 31, 2014

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Exhibits

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher J. Kilpatrick. My business address is 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota 57701.

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

A. I am currently employed by Black Hills Utility Holdings, Inc. ("Utility Holdings"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), as the Director of Regulatory.

Q. ON WHOSE BEHALF ARE YOU APPEARING ON IN THIS APPLICATION?

A. I am testifying on behalf of Black Hills Power, Inc., ("Black Hills Power" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I am a graduate of Mount Marty College in Yankton, South Dakota, with a Bachelor of Arts Degree in Accounting. I am a Certified Public Accountant ("CPA"), a member of the American Institute of Certified Public Accountants, and a member of the South Dakota CPA Society. My work experience includes working for two public accounting firms from 1994 through 1999. The first was Wohlenberg, Ritzman, and Co., located in Yankton, South Dakota, and the second was Ketel Thorstenson, LLP, located in Rapid City, South Dakota.

I began my career with BHC in January 2000 in the internal audit department. In August of 2003, I became the controller of Black Hills FiberCom until February 2005, when I accepted the position of Director of Accounting – Retail Operations. In August 2008, I was offered and accepted the position of Director of Rates. In 2011, I accepted an expanded role, responsible for both electric rates and resource planning. In 2013, BHC reorganized its Resource Planning department and I am now the Director of Regulatory.

Q. BRIEFLY DEFINE YOUR DUTIES AND RESPONSIBILITIES.

A. I am responsible for the revenue requirement calculation and rate design for BHC's utility subsidiaries.

II. <u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the revenue requirement in this proceeding. In particular, I describe: 1) the Phase In Plan Rate ("PIPR") revenue; 2) the Cheyenne Prairie Generating Station ("CPGS") pipeline cost allocations; 3) the proposed changes to the Energy Cost Adjustment ("ECA"); 4) the regulatory asset for decommissioning costs and the proposed amortization of those costs; 5) the regulatory asset for Winter Storm Atlas and the proposed amortization of those costs; and 6) the proposed regulatory asset for the FutureTrack Workforce Development program. In addition, I describe the Company's Cost Allocation Manuals with Black Hills Service Company, LLC ("Service Company") and Utility Holdings.

III. PHASE IN PLAN RATE REVENUE

Q. PLEASE DESCRIBE THE PIPR.

A. The PIPR is the recovery mechanism established by the South Dakota Public Utilities Commission ("Commission") in Docket No. EL12-062. The purpose of the PIPR is to recover the actual construction financing costs related to CPGS before the facility is included in rate base, thereby avoiding Allowance for Funds Used During Construction ("AFUDC"). The rate base with the PIPR is $9.5 million less than the rate base that would exist if AFUDC was included. The PIPR also results in a gradual increase in customer rates through a small increase each quarter.

Q. WHAT IS THE PURPOSE OF THE ADJUSTMENT ON SCHEDULE I-2?

A. The adjustment on Schedule I-2 estimates monthly financing costs collected through the PIPR and annualizes the last five months to properly reflect what customers rates will be prior to new rates going into effect. This amount is then compared to the PIPR revenue collected during the test year and the difference is the resulting adjustment, included on Statement I Page 1 (line 4), which increases operating revenue.

Q. WHY IS THIS ADJUSTMENT NECESSARY?

A. This adjustment is necessary to properly reflect the full benefit of the PIPR. The PIPR is gradually increasing customers' rates each quarter, and this increase in rates through the PIPR needs to be reflected as an adjustment to operating revenue. The adjustment on Statement I, page 1, reduces the overall increase necessary when CPGS is placed into service and thereby properly matches what customers are paying in September and appropriately reduces the revenue deficiency. This adjustment is consistent with the design of the PIPR and the desire to help customers adjust to the new rates that will become effective on October 1, 2014.

IV. CPGS PIPELINE COST ALLOCATION

Q. PLEASE DESCRIBE THE CPGS PIPELINE.

A. The CPGS Pipeline is a high pressure natural gas pipeline that is approximately ten and one-half (10.5) miles in length and is twelve (12) inches in diameter. This pipeline connects Southern Star Central Gas Pipeline (located near the Wyoming/Colorado border) to CPGS. The CPGS Pipeline will be wholly owned and operated by Cheyenne Light, Fuel and Power Company's ("Cheyenne Light") gas utility division. The CPGS Pipeline is discussed at length in the testimony of Kent Kopetzky.

Q. HOW ARE COSTS ALLOCATED BETWEEN BLACK HILLS POWER AND CHEYENNE LIGHT?

A. The contribution in aid of construction for the CPGS Pipeline is calculated based upon Black Hills Power's share of CPGS, which is (42%). This payment is shown on Schedule D-3, Line 15.

V. ENERGY COST ADJUSTMENT ("ECA")

Q. PLEASE DESCRIBE THE ECA.

A. The ECA consists of two adjustment clauses. The first adjustment clause is the Fuel and Purchased Power Adjustment ("FPPA"). The second adjustment clause is the Transmission Cost Adjustment ("TCA").

Q. IS THE COMPANY PROPOSING CHANGES TO THE ECA?

A. Yes. Black Hills Power is proposing changes to the FPPA clause contained within the ECA.

Q. PLEASE GENERALLY DESCRIBE THE CURRENT FPPA CALCULATION.

A. The FPPA is the mechanism Black Hills Power utilizes to recover the costs associated with fuel, fuel handling, purchase power, and other related costs (the "Annual System Fuel and Purchased Power Costs"). To calculate the current FPPA, the Annual System Fuel and Purchase Power costs are reduced through a sharing mechanism called the Power Marketing Operating Income credit. This Sharing mechanism equates to 65% of Black Hills Power's Power Marketing Operating Income. The current minimum Power Marketing Operating Income credit is $2 million. The current FPPA is set forth in Tariff Sheets 1-4, Section 3C.

Q. WHAT CHANGES TO THE FPPA ARE BEING PROPOSED IN THIS CASE?

A. The Company is proposing four changes to the FPPA. The first change is the inclusion of any difference in ad valorem or property taxes, from what is reflected in base rates, in the FPPA. Second, in Docket No. EL12-062, the Company agreed to begin providing its customers a credit for 100% of its wholesale contract revenue on October 1, 2014. The Company is proposing the mechanism to provide this credit through the FPPA. Third, the Company proposes the elimination of the Power Marketing Credit minimum. Finally, the Company proposes that 100% of the costs related to short-term planning reserve capacity purchases and sales be recovered through the FPPA.

Q. DOES BLACK HILLS POWER PROPOSE CHANGING THE BASE ENERGY COST PER KWH IN THIS RATE CASE APPLICATION?

A. No. The base unit cost was set in Docket No. EL09-018 at $0.0146/kWh and Black Hills Power does not propose it be changed. Each annual filing determines an increase or decrease from the base cost per kWh.

Q. PLEASE EXPLAIN THE CHANGE THE COMPANY IS PROPOSING REGARDING AD VALOREM OR PROPERTY TAXES.

A. Pursuant to S.D.C.L. § 49-34A-25, the Company is entitled to recover ad valorem or property taxes. Black Hills Power proposes including in the FPPA any property tax amount that deviates from the amount included in base rates. This inclusion is shown on Statement P, page 1, line 19 and illustrated in Exhibit CJK-1.

Q. WHY IS BLACK HILLS POWER PROPOSING INCLUDING CHANGES TO PROPERTY TAXES IN THE FPPA?

A. The Company is making this proposal to provide rate mitigation for its customers. Black Hills Power anticipates its property taxes will increase when CPGS is placed in service. If the Company's proposal is approved, the property tax increase associated with CPGS will not be included in base rates in October of 2014. Instead, the increase will be deferred until the Company makes its FPPA filing in April of 2015.

Q. HOW IS BLACK HILLS POWER CREDITING LONG TERM WHOLESALE CONTRACT REVENUE TO CUSTOMERS?

A. The Company is including a credit for long term wholesale contract revenue in base rates. Any incremental change in the annual long term wholesale contract revenue will flow through the FPPA. An example of the proposed FPPA calculation is set forth in Exhibit CJK-1. Exhibit CJK-2 contains the proposed FPPA tariff sheets that are also included in tariff Section 3C, Sheets 12 through 15.

Q. DOES THIS PROPOSAL PROVIDE CUSTOMERS A 100% CREDIT OF THE REVENUES FROM LONG-TERM WHOLESALE CONTRACTS?

A. Yes. Customers receive 100% of the revenues from the long-term wholesale contracts, of one year or more, through the annual FPPA filings.

Q. WHY IS THE COMPANY CREDITING BASE RATES INSTEAD OF FLOWING THE CREDIT ENTIRELY THROUGH THE FPPA?

A. Customers will realize the long term wholesale contract revenue credit sooner under this proposal. In particular, new base rates will become effective on October 1, 2014. As reflected on Statement P, page 1, line 27, a $19,288,845 long term wholesale contract revenue credit is reflected in base rates. If the credit flowed entirely through the FPPA, customers would not realize the credit until the Company makes its FPPA filing in April of 2015.

Q. PLEASE EXPLAIN THE CHANGE THE COMPANY IS PROPOSING TO THE POWER MARKETING CREDIT.

A. The Company proposes eliminating the existing Power Marketing Credit minimum. Elimination of this minimum credit is appropriate because the Company's generation resource mix is changing significantly from what it was when the minimum credit was established in 2010. In particular, the Company has retired three of its coal-fired generation facilities. This decrease in base load coal facilities reduces the amount of low cost energy the Company has available to market. As a consequence, the Company's ability to make short-term market sales, i.e. create Power Marketing Operating Income, is greatly reduced. Elimination of the Power Marketing Credit minimum is justified due to the significant change in the generation resource mix and the fact that 100% of long-term wholesale revenues are now credited to customers.

Q. IS THE COMPANY PROPOSING ANY OTHER CHANGES TO THE FPPA?

A. Yes. The Company proposes that 100% of the costs and revenues related to short-term planning reserve capacity purchases be recovered through the FPPA.

Q. WHAT IS CONSIDERED A "SHORT-TERM" PLANNING RESERVE CAPACITY PURCHASE FOR THE PURPOSES OF THIS PROPOSAL?

A. A "short-term" planning reserve capacity purchase is an agreement to purchase capacity for a period of 31 days or less.

Q. UNDER WHAT CIRCUMSTANCES DO YOU EXPECT THAT BLACK HILLS POWER MAY NEED TO PURCHASE SHORT-TERM PLANNING RESERVE CAPACITY?

A. Under normal operations, Black Hills Power's system provides sufficient capacity to ensure that peak customer loads will be reliably and economically met. This is achieved through, among other things, forecasting peak customer demand, and maintaining sufficient resources to meet the forecasted demand plus a capacity reserve margin. On occasion, however, Black Hills Power may experience an unexpected plant outage or other contingency that would cause its allocated resources to fall below the forecasted demand plus the reserve margin. In those circumstances, Black Hills Power will seek to make a short-term reserve capacity purchase to ensure that customers receive continuous reliable service.

Q. WHY IS THE COMPANY MAKING THIS PROPOSAL AT THIS TIME?

A. Historically, there has been no market for short-term capacity purchases available to serve Black Hills Power's customers. Therefore, in the event that Black Hills Power has needed additional resources due to an unexpected contingency, Black Hills Power has been required to purchase firm energy. Through collaboration with South Dakota Public Utilities Commission Staff, a group of Black Hills Power's industrial customers, and the Wyoming Office of Consumer Advocate, Black Hills Power and Cheyenne Light developed a Planning Reserve Capacity Agreement. The agreement allows Black Hills Power and Cheyenne Light to share firm capacity to cover short term contingencies, when it is available and an economic benefit for both parties to do so. The agreement should reduce Black Hills Power's reliance on more expensive firm energy purchases, and also create opportunities to make short-term capacity sales. There is not presently a mechanism, however, for Black Hills Power to either recover the costs of purchases under the agreement, or credit customers for the revenues received under the agreement. Therefore, the Company is proposing that the cost for purchases and credit for sales be addressed through the FPPA.

Q. WHEN WILL THE PROPOSED REVISIONS TO THE FPPA BECOME EFFECTIVE?

A. If approved, the proposed revisions to the FPPA calculation will become effective on October 1, 2014.

Q. WHEN WILL THE CURRENT FPPA CALCULATION BE DISCONTINUED?

A. The current FPPA is calculated in tariff Section 3C, Sheets 1-4, and is in effect until September 30, 2014. The current FPPA calculation will be used for costs incurred by the Company through September 30, 2014. After this date, the new proposed FPPA calculation will become effective. Based on the current annual filing methodology, the FPPA filing that would occur in April 2015 would use two different FPPA calculations to establish the ECA rate that would be charged or refunded to customers. The filing in April 2015 would use the current FPPA calculation for April through September of 2014, and the proposed FPPA calculation from October 2014 through March of 2015.

VI. DECOMMISSIONING REGULATORY ASSET

Q. DOES BLACK HILLS POWER'S PLAN TO DECOMMISSION ITS BEN FRENCH, NEIL SIMPSON I, AND OSAGE FACILITIES IMPACT THE REVENUE REQUIREMENT?

A. Yes. The costs associated with decommissioning the above facilities result in an increase to rate base of approximately $13.9 million. Schedule J-2 of the revenue requirement lists the estimated Regulatory Asset for the Amortization of Decommissioning costs. The total amount, less an adjustment for the first year of recovery, is carried forward to Statement M, line 27, Other Rate Base Reductions, as an increase to rate base. Please refer to the testimony of Mark Lux for additional details regarding decommissioning.

Q. HAVE THESE FACILITIES BEEN REMOVED FROM PLANT-IN-SERVICE?

A. Yes. The retirement of Ben French, Neil Simpson I and Osage is reflected on Statement D page 2 (column d) of the revenue requirement, in the amount of $54,755,892. The adjustment for the elimination of operations and maintenance expense related to the three facilities is in Schedule H-18.

Q. PLEASE DESCRIBE THE TREATMENT OF THE COSTS TO DECOMMISSION NEIL SIMPSON I, OSAGE AND BEN FRENCH.

A. These facilities are scheduled to be decommissioned, demolished, and remediated by mid-2015. In Docket No. EL13-036, Black Hills Power received permission from the Commission to establish a regulatory asset for the cost of decommissioning. This unamortized regulatory asset, with adjustments, is calculated and adjusted for on Schedule J-2. In particular, line 6 represents the sum of the production plant estimated regulatory asset, which is approximately $17,400,000 or approximately $3.5 million of annual amortization expense.

Q. OVER WHAT TIME PERIOD IS BLACK HILLS POWER REQUESTING RECOVERY OF THE COSTS CONTAINED WITHIN THIS REGULATORY ASSET?

A. Black Hills Power is requesting recovery of the regulatory asset over a five year period commencing in 2015. This time period provides a balance between the amount of time required to minimize impact to customers and matching the expense as best as possible with the customers who have utilized the assets being retired.

Q. HOW DID YOU ARRIVE AT THE PROPOSED AMORTIZATION PERIOD FOR DECOMMISSIONING COSTS?

A. The proposed amortization period achieves an annual amortization expense that is approximately equivalent to the annual amount that it would cost to continue to operate these facilities. In particular, Table 1 below illustrates recent annual operating costs for these facilities, not including fuel.

Table 1. Summary of Annual Plant Costs if not decommissioned (Excluding Fuel)

	(a) Operating Costs Excluding Fuel	(b) Depreciation Costs	(c) Total Costs
Neil Simpson I	$1,436,035	$777,866	$2,213,901
Ben French	2,037,564	416,024	2,453,588
Osage		465,658	465,658
Totals	$3,473,599	$1,659,548	$5,133,147

The above annual operating costs are approximately $1.7 million more than the $3.5 million proposed total amortization amount set forth in Schedule J-2 of the revenue requirement.

Q. WHY HAS THE AMOUNT FOR OBSOLETE INVENTORY BEEN INCLUDED ON SCHEDULE J-2?

A. The decommissioning of Osage, Ben French and Neil Simpson I includes the sale of obsolete inventory at each facility. The winning bid for the decommissioning contract includes a credit to the Company for these sales. The estimated decommissioning costs, as shown in column (g) on Schedule J-2, includes a lump sum credit for the remaining inventory at each facility. Thus, the lump sum credit reduces the total decommissioning costs of the facilities. The contractor selected to decommission the units is responsible for the removal and sale of the remaining inventory. The inventory has been assigned to each unit and has been removed from rate base on Schedule F-1.

Q. HOW DOES THE ESTABLISHMENT OF A REGULATORY ASSET BENEFIT CUSTOMERS?

A. A regulatory asset will allow for the recovery of these costs over a number of years. This will minimize the increase that will impact customer rates as a result of this rate case proceeding.

VII. WINTER STORM ATLAS REGULATORY ASSET

Q. HAS THE COMMISSION PREVIOUSLY CONSIDERED A FILING RELATED TO THE COSTS ASSOCIATED WITH WINTER STORM ATLAS?

A. Yes. The Commission granted Black Hills Power the authority to establish a regulatory asset in Docket No. EL13-036. This regulatory asset includes the incremental storm related costs for Winter Storm Atlas. For additional discussion regarding Winter Storm Atlas, please refer to the testimony of Vance Crocker.

Q. WHAT COSTS WERE INCLUDED IN THE REGULATORY ASSET WHEN IT WAS APPROVED?

A. At the time Black Hills Power's Application in EL13-036 was approved, storm costs included in the regulatory asset were approximately $2.7 million.

Q. IS BLACK HILLS POWER REQUESTING ADDITIONAL COSTS BE ADDED TO THIS REGULATORY ASSET?

A. Yes. Black Hills Power estimates there are approximately $0.3 million in additional Winter Storm Atlas costs that should be added to the regulatory asset for costs paid during January and February of 2014. These costs were not included in the accounting order for the regulatory asset because not all invoices had been received at the time the docket was finalized.

In addition, Black Hills Power requests the authority to include the costs of conducting a line patrol of its 69 kV system in the Winter Storm Atlas regulatory asset. Schedule J-3 details the estimated costs associated with the line patrol, referred to as 2014 BHP SD System Inspection Costs, in the amount of $1.14 million. For additional information regarding the line patrol project, please refer to the testimony of Vance Crocker. Please also refer to Exhibit CJK-3 for the Request for Accounting Order for these additional costs.

Q. WHAT IS THE TOTAL PROPOSED VALUE OF THE WINTER STORM ATLAS REGULATORY ASSET?

A. The total proposed value of the Winter Storm Atlas regulatory asset is approximately $4.14 million. The total unamortized regulatory asset requested for Winter Storm Atlas, shown on Schedule J-3, is approximately $3.31 million. Black Hills Power proposes amortizing $4.14 million over a five year period, for an annual amortization expense of approximately $827,700.

VIII. FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM

Q. HOW DOES BLACK HILLS POWER PLAN TO TREAT THE COSTS ASSOCIATED WITH THE FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM DESCRIBED IN THE TESTIMONY OF JENNIFER LANDIS?

A. Schedule H-19 of the revenue requirement model, Section 4, includes a total Company annual expense for the FutureTrack Workforce Development Program in the amount of $721,861, for the test year ended September 30, 2013. The Company is requesting that the Commission approve an accounting order to create a regulatory asset for any expenses that deviate from the annual expense included in rate base. The Request for Accounting Order for the FutureTrack Program is contained in Exhibit CJK-4. If in any of the eight years the annual expenditures are less than the amount in base rates, the amount of the difference will be credited to customers through the regulatory asset. In particular, Black Hills Power is requesting that expenditures for the program that exceed the amount in base rates annually over each of the next eight years be recorded in a regulatory asset.

Q. UNDER THE COMPANY'S PROPOSAL, HOW WILL THE FUTURETRACK REGULATORY ASSET BE TREATED AT THE END OF THE EIGHT YEAR PERIOD?

A. The Company requests that at the end of the eight year period, the balance in the regulatory asset be amortized over the next three years in order to recover costs from customers who directly benefit from the program. The Company also requests that the balance of the regulatory asset be recovered through a tariff or rate increase to be determined prior to year eight.

Q. HOW DO CUSTOMERS BENEFIT FROM THIS PROPOSAL?

A. Customers benefit from this program because costs are spread over a period of time. Additionally, this program will help ensure Black Hills Power's continued ability to safely and reliably deliver electricity.

Q. PLEASE DESCRIBE HOW THE COMPANY PLANS TO REPORT THE ANNUAL COSTS ASSOCIATED WITH THE FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM?

A. Black Hills Power proposes an annual filing requirement that will report the annual expenditures and the status of the program.

IX. CORPORATE COST ALLOCATIONS

Q. DOES BLACK HILLS POWER RECEIVE SERVICES FROM OTHER CORPORATE ENTITIES?

A. Black Hills Power obtains services from Service Company and Utility Holdings, which are subsidiaries of BHC.

Q. WHAT TYPES OF SERVICES DOES BLACK HILLS POWER RECEIVE FROM SERVICE COMPANY AND UTILITY HOLDINGS?

A. Service Company provides central services such as human resources, legal, finance, and generating plant operations to Black Hills Power. Utility Holdings provides services to Black Hills Power that are primarily related to customer service, billing and information technology.

Q. HOW DOES BLACK HILLS POWER BENEFIT FROM THE SERVICES OF SERVICE COMPANY AND UTILITY HOLDINGS?

A. The services provided by Service Company and Utility Holdings avoid the duplication of these business functions by each of the regulated and non-regulated business units of BHC, including Black Hills Power. This business arrangement creates efficiencies compared to stand-alone business functions at each separate business unit.

Q. ARE THESE SERVICES PROVIDED UNDER A WRITTEN AGREEMENT?

A. Yes, Black Hills Power has Service Agreements with Service Company and Utility Holdings. Both Service Company and Utility Holdings provide their services at cost to Black Hills Power and other BHC affiliates through direct charges and indirect charges. Expenses for support services are charged to Black Hills Power on a monthly basis pursuant to the Service Agreements. A copy of the Service Company Service Agreement is attached to my testimony as Exhibit CJK-5. A copy of the Utility Holdings Service Agreement is attached as Exhibit CJK-6.

Q. IS THE PROPOSED METHOD OF CORPORATE COSTS ALLOCATIONS CONSISTENT WITH HOW SIMILAR ALLOCATIONS WERE HANDLED IN PAST RATE CASE?

A. Yes. Black Hills Power is allocating corporate costs based on the Cost Allocation Manuals (CAM). The CAMs for Service Company and Utility Holdings are provided as Exhibit CJK-7 and Exhibit CJK-8. These CAMs are generally consistent with the last rate case for the Company in 2012 with a few updates to the descriptions to departments or other clarifying items.

Q. DO THESE ALLOCATIONS OF INDIRECT COSTS RESULT IN A FAIR AND EQUITABLE COST BEING BILLED TO BLACK HILLS POWER?

A. Yes. The methods used by Service Company and Utility Holdings were established by reviewing relevant cost factors and are consistent with industry practice in allocating common costs. In addition, services that are identified to a specific project or company are directly billed to that project or company. The combination of assigning direct costs for identifiable expenses and allocation of indirect costs fairly and accurately represents Black Hills Power's share of the costs of Service Company and Utility Holdings in the provision of services to Black Hills Power.

X. CONCLUSION

Q. DOES THE REVENUE REQUIREMENT RESULT IN A JUST AND REASONABLE REVENUE REQUIREMENT?

A. Yes. The revenue requirement uses the per books financial statements for the test year ending September 30, 2013, which contains known and measurable adjustments. The effect is a straight-forward application supporting the requested increase in base rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibit CJK-1

Black Hills Power
Fuel and Purchase Power Adjustment Example
For Rates Effective on October 1, 2014

Line No.	FERC Acct. #		(1) Rate Case Reference	(2) Amounts Included in Base Rates	(3) Amounts Included in the FPPA Filing in April 2015	
1	501	Fuel and Fuel Handling	Stmt H; lns 3-7	$ -	$ 9,000,000	(a)
2	502	Reagent Costs (Lime; Ammonia; Mercury Sorbent)	Stmt H; ln 8	-	1,200,000	(a)
3	555	Purchase Power	Stmt H; ln 45	-	5,800,000	(a)
4	547	Fuel - Other Plant (Delivered Natural Gas Cost)	Stmt H; ln 27	-	3,000,000	(a)
5		Power Marketing Operating Income	Stmt I pg 1; ln 9 & Sched H-12	-	(750,000)	(b)
6		Annual System FPP Costs that would be reported on Section No 3C, Sheet 12, Line 1			18,250,000	
7						
8	408	Property Taxes	Stmt P pg 1; ln 19	4,049,818	500,000	(c)
9	447	Sales for Resale (Long-Term Wholesale Contracts)	Stmt P pg 1; ln 27	19,288,845	700,000	(d)
10		Incremental South Dakota Jurisdictional Costs reported on Section 3C, Sheet 12, Line 10			1,200,000	
11						
12	Note (a)	These amounts represent 100% of those costs passed through to customers in the April 2015 filing from				
13		October 1, 2014 through March 31, 2015.				
14	Note (b)	This amount represents 65% of the total Power Marketing Operating Income from October 1, 2014				
15		through March 31, 2015.				
16	Note (c)	This amount will represent the difference from the amount included in base rates to the actual amount				
17		from October 1, 2014 through March 31, 2015 (prorated for the six month time period).				
18	Note (d)	This amount will represent the difference from the amount included in base rates to the actual amount				
19		from October 1, 2014 through March 31, 2015 (prorated for the six month time period). A positive				
20		amount here would represent lower revenue as compared to the amount in base rates and a negative				
21		amount here would represent higher revenue as compared to the amount in base rates. Long-Term				
22		Wholesale contracts are defined as one year or longer.				
23						
24	**Overall Note:**	The amounts listed in Column (3) are for illustration purposes only.				

FUEL AND PURCHASED POWER ADJUSTMENT

APPLICABLE

(N)

This Fuel and Purchased Power Adjustment (FPPA) applies to all rate schedules for all classes of service authorized by the South Dakota Public Utilities Commission (Commission).

The FPPA shall be calculated annually based on actual system costs for Fuel and Purchased Power (FPP) for the twelve months of April through March as compared to the base year FPP costs, and shall include an over-or-under recovery from prior years' adjustments through the Balancing Account. Black Hills Power, Inc. (the Company) will update and make a FPPA filing with the Commission on an annual basis no later than May 10th.

FUEL AND PURCHASED POWER ADJUSTMENT CALCULATION		For the Twelve months ended ______	
1.	Annual System FPP Costs	$ ______	
2.	Annual Retail Energy Sales	______	kWh
3.	FPP Cost / kWh (Line 1 ÷ Line 2)	$ ______	/kWh
4.	Approved Base FPP Costs	$ 0.0146	/kWh
5.	FPP Cost / kWh Difference (Line 3 – Line 4)	$ ______	/kWh
6.	Total FPP Change from Base (Line 2 x Line 5)	$ ______	
7.	South Dakota Annual Retail Energy Sales	______	kWh
8.	Total SD (Refund)/Charge (Line 5 x Line 7)	$ ______	
9.	SD Balancing Account (+/-)	$ ______	
10.	Incremental SD Jurisdictional Costs	$ ______	
11	Rate Case True-up Items	$ ______	
12.	Net SD Amount to (Refund)/Charge (Line 8 through Line 11)	$ ______	
13.	Projected South Dakota Retail Energy Sales	______	kWh
14.	SD FPPA (Line 12 ÷ Line 13)	$ ______	/kWh

FUEL AND PURCHASED POWER ADJUSTMENT

ANNUAL SYSTEM FUEL AND PURCHASED POWER (FPP) COSTS (Line 1)

(N)

FPP Costs include all purchased power; fuel consumed for plant generation, including but not limited to coal, fuel oil and natural gas; plus costs for certain re-agents used in conjunction with fuel consumed for plant generation less costs associated with Power Marketing; and a sharing of Power Marketing Operating Income. The Annual System FPP Costs shall be calculated on an annual basis using the total of:

a. Total fuel costs of the Company's generation for items listed in the Federal Energy Regulatory Commission's (FERC) Accounts: 501 for Fuel and 547 for Other Power Production, as well as any other costs of fuel consumed to generate electricity not listed in these two accounts. The base price for coal, included in this cost, is determined in accordance with the methodology set forth in the Statement R of the Company's 2006 rate application Docket No. EL06-019;

b. The costs of re-agents necessary to use in conjunction with fuel consumed for plant generation. This includes lime and the associated freight, ammonia and other chemicals.

c. The costs of all energy or short term capacity purchases listed under FERC account 555;

d. Less, Ninety percent (90%) of the share of margin generated by the sale of Renewable Energy Credits;

e. Less, FPP used for Power Marketing Sales; and

f. Less a share of Power Marketing Operating Income as described below.

POWER MARKETING OPERATING INCOME (PMOI)

As an incentive to provide the lowest cost FPP to customers, Power Marketing revenues and expenses will be included in the Fuel and Purchase Power Adjustment clause as follows:

a. Power Marketing Sales revenues are defined as short-term (generally less than one year) energy or capacity sales to wholesale customers and sales of emission allowances.

b. The Company's long-term (generally one year or longer) customer obligations will be served with the lowest cost resources during each hour that the Company engages in Power Marketing Sales except for the following: 1) Any renewable resource energy; and 2) Specific energy or capacity blocks, up to 75MW, purchased to cover capacity needs for 3 weeks or more [but not to exceed 6 months] in length. For these two situations, the cost of capacity or energy shall be directly assigned to the Company's long-term customers. Any remaining resources may be scheduled for, and if scheduled will be charged to, Power Marketing Sales as the costs of goods sold.

c. Fifty percent (50%) of the base salary and benefit costs of the Company's generation dispatch and power marketing personnel shall be included as a power marketing expense

FUEL AND PURCHASED POWER ADJUSTMENT

POWER MARKETING OPERATING INCOME (Continued) (N)

d. Any transmission expense incurred to facilitate Power Marketing Sales shall be included as an expense.

e. Bonuses payable to the Company's generation dispatch and power marketing personnel as a result of Power Marketing Sales shall be included as an expense.

f. Any specifically identified expenses associated with Power Marketing Sales, such as legal expense or bad debt expense, shall be included as an expense.

SHARING OF POWER MARKETING OPERATING INCOME

The calculated Pre-Tax PMOI will be multiplied by 65% to determine the amount of the credit to be applied as a reduction to the FPP costs.

ANNUAL RETAIL ENERGY SALES (Line 2)

Annual Retail Energy Sales are the total sales of Electricity, for retail customers.

BASE FPP COSTS (Line 4)

The Base FPP Costs are as approved by the Commission in Docket No. EL09-018.

SOUTH DAKOTA ANNUAL RETAIL ENERGY SALES (Line 7)

The South Dakota Annual Retail Energy Sales are the total South Dakota retail energy kilowatt hour sales for the previous period for all classes of service authorized by the Commission.

SD BALANCING ACCOUNT (Line 9)

This Balancing Account amount on Line 9 (positive or negative) is the amount from the previous filing (SD Net Amount to (Refund)/Charge) less the actual FPPA amount (Refunded) or Charged for the period, adjusted for applicable interest. The Balancing Account shall have interest applied or credited monthly at the annual rate of seven percent (7%). The FPPA (Refund)/Charge will be applied monthly to the Balancing Account, first to the interest balance, and thereafter to the principal amount.

INCREMENTAL SD JURISDICTIONAL COSTS (Line 10)

These costs represent the difference of the actual ad valorem and wholesale contract revenue as compared to the amount in base rates as approved in Docket No. EL14-___, Statement P, page 1, lines 19 and 27.

FUEL AND PURCHASED POWER ADJUSTMENT

(N)

RATE CASE TRUE-UP ITEMS (Line 11)

The Rate Case True-up Items adjustment includes items that need to be charged or (refunded) to customers as a result of rate case items to be handled outside of the general rate case. These items are handled in the time period required per the outcome of each case. The total dollar amount may reflect items from various cases.

NET SD AMOUNT TO (REFUND)/CHARGE (Line 12)

The net amount to refund or charge customers is the South Dakota's share of the total Net FPP costs adjusted by the Balancing Account (Line 8 through Line 11).

PROJECTED SOUTH DAKOTA RETAIL ENERGY SALES (Line 13)

These are the kilowatt hours of retail sales projected for the State of South Dakota for the period that the FPPA (Line 14) will be in effect.

SD FUEL AND PURCHASED POWER ADJUSTMENT (Line 14)

The FPPA on Line 14 shall be included in the Company's annual Energy Cost Adjustment and shall be applied to all rate schedules in all classes of service authorized by the Commission.

EFFECTIVE DATE

The FPPA will be updated and filed annually with the effective date of June 1st.

EXHIBIT CJK-3

REQUEST FOR ACCOUNTING AUTHORITY ORDER

ALLOWING BLACK HILLS POWER TO INCLUDE ADDITIONAL COSTS IN THE REGULATORY ASSET APPROVED IN DOCKET NO. EL 13-036

Black Hills Power, Inc. ("Black Hills Power" or the "Company") requests that the South Dakota Public Utilities Commission ("Commission") approve an accounting authority order permitting Black Hills Power to include additional costs in the regulatory asset approved in Docket No. EL 13-036. Black Hills Power requests this accounting authority order be approved if the pending rate case is not resolved prior to December 31, 2014.

1) On January 9, 2014, the Commission granted Black Hills Power the authority to establish a regulatory asset in Docket No. EL13-036 for the incremental costs incurred in relation to Winter Storm Atlas. When the regulatory asset was approved, Black Hills Power had paid incremental costs in the amount of $2.5 million as of November 30, 2013.

2) All storm related invoices had not been received when the regulatory asset was approved. Black Hills Power has an additional $0.5 million in associated costs since the approval and requests that these costs be included in the regulatory asset.

3) Black Hills Power has also determined that it is necessary to conduct a ground patrol of its Black Hills communities to identify any latent damage caused by Winter Storm Atlas. Black Hills Power estimates that the costs associated with

this ground patrol project will be approximately $1.142 million. Black Hills Power requests that this amount also be included in the regulatory asset.

4) The Company requests that it receive a yearly rate of return on the balance in the Winter Storm Atlas regulatory asset. The rate of return will be equal to the rate of return approved by the Commission in this rate case.

If the Commission approves Black Hills Power's request, Black Hills Power will hold its deferred costs in Account No. 182.3, Other Regulatory Assets, until consideration of cost recovery occurs in the base rate proceedings. Permitting this treatment will allow Black Hills Power to make appropriate adjustments on its books for the regulatory asset and prevent it from having to record Winter Storm Atlas related incremental costs as expenses on its books in a condensed time period.

EXHIBIT CJK-4

REQUEST FOR ACCOUNTING AUTHORITY ORDER ALLOWING BLACK HILLS POWER TO USE DEFERRED ACCOUNTING FOR COSTS ASSOCIATED WITH THE FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM THAT DEVIATE FROM THE ASSOCIATED COSTS INCLUDED IN BASE RATES

Black Hills Power, Inc. ("Black Hills Power" or the "Company") requests that the South Dakota Public Utilities Commission ("Commission") approve an accounting authority order permitting Black Hills Power to use deferred accounting for costs associated with the FutureTrack Workforce Development Program that deviate from the associated costs included in base rates.

1) Black Hills Power has requested that the Commission approve the inclusion of $675,845 in base rates over the next eight years for the FutureTrack Workforce Development Program. Provided the Commission approves this amount, Black Hills Power proposes that any deviation from this amount be recorded in a regulatory asset.

2) The Company requests that it receive a yearly rate of return on the balance in the FutureTrack Workforce Development Program regulatory asset. The rate of return will be equal to the rate of return approved by the Commission in this rate case.

3) An annual report to the Commission will be provided to demonstrate the actual costs incurred and progress of the overall program.

4) The Company requests that at the end of the eight year period, the balance in the regulatory asset be amortized over the next three year period.

5) The Company requests that the recovery of the FutureTrack Regulatory Asset commence in year nine in the form of a tariff or rate increase to be approved by the Commission prior to year eight.

BLACK HILLS POWER, INC.
FUTURETRACK WORKFORCE DEVELOPMENT PROGRAM
For the Pro Forma Test Year Ended September 30, 2013

Line No.	FERC Acct. #	Description	Reference	Amount	Schedule N-1 Alloction	SD Amount
1		**Salaries and Benefit Expenses**				
2	502	Steam Plant Operation		$ 61,140	DPROD	$ 54,923
3						
4	512	Steam Plant Boilers Maintenance		82,471	DPROD	74,085
5						
6	580	Distribution Supervision		77,834	SALWAGDO	72,694
7						
8	593	Distribution Overhead Line Maintenance		345,337	OHDIST	327,569
9						
10	908	Customer Assistance		99,223	CUSTASST	95,369
11						
12	920	Administration		55,856	SALWAGES	51,205
13						
14		**Annual Strategic Workforce Planning Expense**	Sum(Ln. 2:Ln. 12)	**$ 721,861**		**$ 675,845**
15						

16 Note: The annual FutureTrack Workforce Development Program expense equals one-eighth of the total cost needed
17 over the next eight years to cover the significant loss of employees related to the baby boomer generation retiring
18 from the company.

SERVICE AGREEMENT
(Utility)

This Service Agreement (the "**Agreement**") is made effective the 1st day of August, 2009 (Effective Date), by and between Black Hills Power, Inc. ("**Client**") and Black Hills Service Company, LLC ("**Service Company**").

WITNESSETH

WHEREAS, Service Company was formed on December 30, 2004, and became operational on January 1, 2006.

WHEREAS, Service Company operates as a centralized service company under the Energy Policy Act of 2005 (the "Act") and the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), pursuant to Order Nos. 667 and 667-A of the Federal Energy Regulatory Commission ("FERC").

WHEREAS, Service Company is a subsidiary of Black Hills Corporation ("Black Hills") and Client is an affiliate of Service Company.

WHEREAS, Service Company and Client have entered into this Agreement whereby Service Company agrees to provide and Client agrees to accept and pay for various services as provided herein at cost, and pursuant to Black Hills Service Company Cost Allocation Manual, with cost determined in accordance with applicable rules and regulations under the Act, which require Service Company to fairly and equitably allocate costs among all associate companies to which it renders services, including Client.

NOW THEREFORE, in consideration of the premises and the mutual agreements herein contained, the parties to this Agreement covenant and agree as follows:

ARTICLE 1
SERVICES

Section 1.1 Service Company shall furnish to Client, as requested by Client, upon the terms and conditions hereinafter set forth, such of the services described in the Black Hills Service Company Cost Allocation Manual ("CAM"), at such times, for such periods and in such manner as Client may from time to time request and that Service Company concludes it is able to perform. Service Company shall also provide Client with such special services, in addition to those services described in the CAM, as may be requested by Client and that Service Company concludes it is able to perform. Service Company shall use its best efforts to maintain a staff trained and experienced in the design, construction, operation, maintenance, and management of public utility properties, and shall keep itself and its personnel available to provide services to Client so long as it is authorized to do so by the appropriate federal and state regulatory agencies. In supplying such services, Service Company may arrange, where it deems appropriate, for the services of such experts, consultants, advisers, and other persons with necessary qualifications as are required for or pertinent to the provision of such services.

Section 1.2 Client shall take from Service Company such of the services described in Section 1.1, and such additional general or special services, whether or not now contemplated as are requested from time to time by Client and that Service Company concludes it is able to perform.

Section 1.3 The services described herein or contemplated to be performed hereunder shall be directly assigned, distributed or allocated by activity, project, program, work order or other appropriate basis. Client shall have the right from time to time to amend, alter or rescind any activity, project, program or work order provided that (i) any such amendment or alteration that results in a material change in the scope of the services to be performed or equipment to be provided is agreed to by Service Company, (ii) the cost for the services covered by the activity, project, program or work order shall include any expense incurred by Service Company as a direct result of such amendment, alteration or rescission of the activity, project program or work order, and (iii) no amendment, alteration or rescission of any activity, project, program or work order shall release Client from liability for all costs already incurred by or contracted for by Service Company pursuant to the activity, project, program or work order, regardless of whether the services associated with such costs have been completed.

ARTICLE 2
COMPENSATION

Section 2.1 As compensation for the services to be rendered hereunder, Client shall pay to Service Company all costs which reasonably can be identified and related to particular services performed by Service Company for or on Client's behalf. The methods for assigning or allocating Service Company costs to Client, as well as to other associate companies, are set forth in the CAM.

Section 2.2 The methods of assignment, distribution or allocation of costs described in the CAM shall be subject to review annually, or more frequently if appropriate. Such methods of assignment, distribution or allocation of costs may be modified or changed by Service Company.

Section 2.3 Service Company shall render a monthly statement to Client that shall reflect the billing information necessary to identify the costs charged for that month. By the twentieth (20th) day of each month, Client shall remit to Service Company all charges billed to it.

Section 2.4 It is the intent of this Agreement that the payment for services rendered by Service Company to Client under this Agreement shall cover all the costs of Service Company doing business (less the costs of services provided to affiliated companies not a party to this Agreement and to other non-affiliated companies, and credits for any miscellaneous items), including, but not limited to, salaries and wages, office supplies and expenses, outside services employed in rendering the services hereunder, property insurance, injuries and damages, employee pensions and benefits, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization, and compensation for use of capital as permitted under the Act.

ARTICLE 3
TERM

Section 3.1 This Agreement shall become effective on the Effective Date and shall continue in force until terminated by Service Company or Client, upon not less than one year's prior written notice to the other party. This Agreement shall also be subject to termination or modification at any time, without notice, if and to the extent performance under this Agreement may conflict with the Act or with any rule, regulation or order of the FERC adopted before or after the date of this Agreement.

ARTICLE 4
LIMITATION OF LIABILITY AND INDEMNIFICATION

Section 4.1 In performing the services hereunder, Service Company will exercise due care to assure that the services are performed in an appropriate manner, meet the standards and specifications set forth in any applicable request for service and comply with the applicable standards of law and regulation. However, failure to meet these obligations shall in no event subject Service Company to any claims by or liabilities to Client other than to reperform the services and be reimbursed at cost for such reperformance. Service Company makes no other warranty with respect to its performance of the services, and Client agrees to accept such services without further warranty of any nature.

Section 4.2 To the fullest extent allowed by law, Client shall and does hereby indemnify and agree to save harmless and defend Service Company, its agents and employees from liabilities, taxes, losses, obligations, claims, damages, penalties, causes of action, suits, costs and expenses or judgments of any nature, on account of, or resulting from the performance and prosecution of any services performed on behalf of Client pursuant to this Agreement, whether or not the same results or allegedly results from the claimed or actual negligence or breach of warranty of, or willful misconduct by, Service Company or any of its employees, agents, clients, or contractors or its or their subcontractors or any combination thereof.

ARTICLE 5
MISCELLANEOUS

Section 5.1 All accounts and records of Service Company shall be kept in accordance with the Uniform System of Accounts for Centralized Service Companies promulgated by the FERC.

Section 5.2 New direct or indirect non-utility subsidiaries of Black Hills, which may come into existence after the Effective Date of this Agreement, may become additional clients of Service Company and subject to a service agreement with Service Company, or an existing client may wish to obtain additional services from Service Company. Likewise, an existing direct or indirect subsidiary of Black Hills may cease to be a client or cease to take individual services from Service Company. In either event, the parties hereto shall make such changes in the scope and character of the services to be rendered and in the method of assigning, distributing or allocating costs of such services as specified in the CAM, as may become necessary to achieve a fair and equitable assignment, distribution, or allocation of Service Company costs among all associate companies.

Section 5.3 In the event Client changes the scope of services that it takes from Service Company (as provided in Section 1.2 and subject to Section 1.3) or terminates this Agreement (pursuant to Section 3.1), the Service Company may bill such Client a charge that reflects a proportionate share of any significant residual fixed costs (i.e. incurred costs or commitments to incur costs) that were incurred or committed to incur in contemplation of providing such Client service prior to the notice of termination. Examples of fixed costs include, but are not limited to, costs to upgrade computer hardware and software systems to meet Client's specifications.

Section 5.4 Service Company shall permit Client access to its accounts and records, including the basis and computation of allocations; provided that the scope of access and inspection is limited to accounts and records that are related to Service Company's transactions with Client.

Section 5.5 It is the intent of the parties hereto that the determination of the costs as used in this Agreement shall be consistent with, and in compliance with, the rules and regulations of the FERC, as they are now read or hereafter may be modified by the FERC.

Section 5.6 This Agreement and the rights hereunder may not be assigned without the mutual written consent of all parties hereto.

* * * * *

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the date and year first above written.

BLACK HILLS SERVICE COMPANY, LLC

By: ______________________
Name: Steven J. Helmers
Title: Sr. Vice President & General Counsel

BLACK HILLS POWER, INC.

By: ______________________
Name: Anthony S. Cleberg
Title: Executive Vice President & CFO

SERVICE AGREEMENT
(Utility)

This Service Agreement (the "**Agreement**") is made effective the 1st day of August, 2009 (Effective Date), by and between Black Hills Power, Inc. ("**Client**") and Black Hills Utility Holdings, Inc. ("**BHUH**").

WITNESSETH

WHEREAS, BHUH was formed on June 9, 2008 and became operational on July 14, 2008.

WHEREAS, BHUH operates as a centralized service company under the Energy Policy Act of 2005 (the "Act") and the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), pursuant to Order Nos. 667 and 667-A of the Federal Energy Regulatory Commission ("FERC").

WHEREAS, BHUH is a subsidiary of Black Hills Corporation ("Black Hills") and Client is a utility operating company and an affiliate of BHUH.

WHEREAS, BHUH and Client have entered into this Agreement whereby BHUH agrees to provide and Client agrees to accept and pay for various services as provided herein at cost, and pursuant to Black Hills Utility Holdings, Inc. Cost Allocation Manual, with cost determined in accordance with applicable rules and regulations under the Act, which require BHUH to fairly and equitably allocate costs among all associate companies to which it renders services, including Client.

NOW THEREFORE, in consideration of the premises and the mutual agreements herein contained, the parties to this Agreement covenant and agree as follows:

ARTICLE 1
SERVICES

Section 1.1 BHUH shall furnish to Client, as requested by Client, upon the terms and conditions hereinafter set forth, such of the services described in the Black Hills Utility Holdings, Inc. Cost Allocation Manual ("CAM"), at such times, for such periods and in such manner as Client may from time to time request and that BHUH concludes it is able to perform. BHUH shall also provide Client with such special services, in addition to those services described in the CAM, as may be requested by Client and that BHUH concludes it is able to perform. BHUH shall use its best efforts to maintain a staff trained and experienced in the design, construction, operation, maintenance, and management of public utility properties, and shall keep itself and its personnel available to provide services to Client so long as it is authorized to do so by the appropriate federal and state regulatory agencies. In supplying such services, BHUH may arrange, where it deems appropriate, for the services of such experts, consultants, advisers, and other persons with necessary qualifications as are required for or pertinent to the provision of such services.

Section 1.2 Client shall take from BHUH such of the services described in Section 1.1 and such additional general or special services, whether or not now contemplated as are requested from time to time by Client and that BHUH concludes it is able to perform.

Section 1.3 The services described herein or contemplated to be performed hereunder shall be directly assigned, distributed or allocated by activity, project, program, work order or other appropriate basis. Client shall have the right from time to time to amend, alter or rescind any activity, project, program or work order provided that (i) any such amendment or alteration that results in a material change in the scope of the services to be performed or equipment to be provided is agreed to by BHUH, (ii) the cost for the services covered by the activity, project, program or work order shall include any expense incurred by BHUH as a direct result of such amendment, alteration or rescission of the activity, project program or work order, and (iii) no amendment, alteration or rescission of any activity, project, program or work order shall release Client from liability for all costs already incurred by or contracted for by BHUH pursuant to the activity, project, program or work order, regardless of whether the services associated with such costs have been completed.

ARTICLE 2
COMPENSATION

Section 2.1 As compensation for the services to be rendered hereunder, Client shall pay to BHUH all costs which reasonably can be identified and related to particular services performed by BHUH for or on Client's behalf. The methods for assigning or allocating BHUH costs to Client, as well as to other associate companies, are set forth in the CAM.

Section 2.2 The methods of assignment, distribution or allocation of costs described in the CAM shall be subject to review annually, or more frequently if appropriate. Such methods of assignment, distribution or allocation of costs may be modified or changed by BHUH.

Section 2.3 BHUH shall render a monthly statement to Client that shall reflect the billing information necessary to identify the costs charged for that month. By the twentieth (20th) day of each month, Client shall remit to BHUH all charges billed to it.

Section 2.4 It is the intent of this Agreement that the payment for services rendered by BHUH to Client under this Agreement shall cover all the costs of BHUH doing business (less the costs of services provided to affiliated companies not a party to this Agreement and to other non-affiliated companies, and credits for any miscellaneous items), including, but not limited to, salaries and wages, office supplies and expenses, outside services employed in rendering the services hereunder, property insurance, injuries and damages, employee pensions and benefits, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization, and compensation for use of capital as permitted under the Act.

ARTICLE 3
TERM

Section 3.1 This Agreement shall become effective on the Effective Date and shall continue in force until terminated by BHUH or Client, upon not less than one year's prior written notice to the other party. This Agreement shall also be subject to termination or modification at any time, without notice, if and to the extent performance under this Agreement may conflict with the Act or with any rule, regulation or order of the FERC adopted before or after the date of this Agreement.

ARTICLE 4
LIMITATION OF LIABILITY AND INDEMNIFICATION

Section 4.1 In performing the services hereunder, BHUH will exercise due care to assure that the services are performed in an appropriate manner, meet the standards and specifications set forth in any applicable request for service and comply with the applicable standards of law and regulation. However, failure to meet these obligations shall in no event subject BHUH to any claims by or liabilities to Client other than to reperform the services and be reimbursed at cost for such reperformance. BHUH makes no other warranty with respect to its performance of the services, and Client agrees to accept such services without further warranty of any nature.

Section 4.2 To the fullest extent allowed by law, Client shall and does hereby indemnify and agree to save harmless and defend BHUH, its agents and employees from liabilities, taxes, losses, obligations, claims, damages, penalties, causes of action, suits, costs and expenses or judgments of any nature, on account of, or resulting from the performance and prosecution of any services performed on behalf of Client pursuant to this Agreement, whether or not the same results or allegedly results from the claimed or actual negligence or breach of warranty of, or willful misconduct by, BHUH or any of its employees, agents, clients, or contractors or its or their subcontractors or any combination thereof.

ARTICLE 5
MISCELLANEOUS

Section 5.1 All accounts and records of BHUH shall be kept in accordance with the Uniform System of Accounts for Centralized Service Companies promulgated by the FERC.

Section 5.2 New direct or indirect non-utility subsidiaries of Black Hills, which may come into existence after the Effective Date of this Agreement, may become additional clients of BHUH and subject to a service agreement with BHUH, or an existing client may wish to obtain additional services from BHUH. Likewise, an existing direct or indirect subsidiary of Black Hills may cease to be a client or cease to take individual services from BHUH. In either event, the parties hereto shall make such changes in the scope and character of the services to be rendered and in the method of assigning, distributing or allocating costs of such services as specified in the CAM, as may become necessary to achieve a fair and equitable assignment, distribution, or allocation of BHUH costs among all associate companies.

Section 5.3 In the event Client changes the scope of services that it takes from BHUH (as provided in Section 1.2 and subject to Section 1.3) or terminates this Agreement (pursuant to Section 3.1), BHUH may bill such Client a charge that reflects a proportionate share of any significant residual fixed costs (i.e. incurred costs or commitments to incur costs) that were incurred or committed to incur in contemplation of providing such Client service prior to the notice of termination. Examples of fixed costs include, but are not limited to, costs to upgrade computer hardware and software systems to meet Client's specifications.

Section 5.4 BHUH shall permit Client access to its accounts and records, including the basis and computation of allocations; provided that the scope of access and inspection is limited to accounts and records that are related to BHUH's transactions with Client.

Section 5.5 It is the intent of the parties hereto that the determination of the costs as used in this Agreement shall be consistent with, and in compliance with, the rules and regulations of the FERC, as they are now read or hereafter may be modified by the FERC.

Section 5.6 This Agreement and the rights hereunder may not be assigned without the mutual written consent of all parties hereto.

* * * * *

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the date and year first above written.

BLACK HILLS UTILITY HOLDINGS, INC.

By: Steven J. Helmers
Name: Steven J. Helmers
Title: Sr. Vice President & General Counsel

BLACK HILLS POWER, INC.

By: Linden R. Evans
Name: Linden R. Evans
Title: President & Chief Operating Officer

Black Hills Service Company

Cost Allocation Manual

Effective Date: July 14, 2008

Amended: January 1, 2010

Amended: August 1, 2010

Amended: December 1, 2013

Black Hills Service Company Cost Allocation Manual

Table of Contents

Introduction

The purpose of this cost allocation manual is to document the allocation processes of Black Hills Service Company, from recording the original transaction through the allocation of costs to Black Hills Corporation subsidiaries. Various topics to be addressed include the organization of the Service Company, the recording of transactions, calculating and assigning allocation factors, and recording allocation transactions.

Black Hills Service Company (the Service Company) was formed on December 30, 2004, and was fully implemented and operational as of January 1, 2006. The Service Company was formed as required by the Public Utility Holding Company Act of 1935, which was administered by the Securities and Exchange Commission (SEC). Service companies were required of all registered holding companies under this law. Service companies coordinate corporate support functions and distribute costs to registered holding company subsidiaries using pre-defined allocation methodologies that had to be approved by the SEC.

Black Hills Corporation became a registered holding company at the end of 2004, and through a transition period and various amendments to the registered holding company filings, established the date of January 1, 2006 to fully implement the Service Company. In August of 2005, this law was repealed and replaced by the Public Utility Holding Company Act of 2005, which is administered by the Federal Energy Regulatory Commission (FERC). This new law was effective in February of 2006. Although certain administrative and reporting requirements changed as a result of the repeal, Black Hills Corporation did not change its implementation plan.

The Service Company is a wholly owned subsidiary of Black Hills Corporation (the Holding Company), and is a separate legal entity. The majority of operations and all employees were transferred out of the Holding Company on the effective date of implementation. The only transactions that remain at the Holding Company are transactions pertaining to long-term debt and related deferred finance costs, corporate credit facility and related deferred finance costs, and the administration of money pool transactions for both the utility money pool and the non-utility money pool. In addition, as will be discussed in greater detail later, certain corporate costs are charged directly to the Holding Company. The most notable of these types of costs are corporate development project costs.

Service Company Organization

The Service Company is organized into operating departments based upon the services that those departments provide to Black Hills Corporation subsidiaries. A list of each department, as well as a brief description of the services they provide, is attached as Appendix 1.

Direct Costs versus Indirect Costs

A key issue in distributing Service Company costs is distinguishing between direct costs and indirect costs. The account coding will change depending on whether the cost is a direct or indirect cost. Below is a summary of each of these types of costs and examples of these costs.

Direct costs are those costs that are specifically associated with an identified subsidiary. This means that it is known exactly to which subsidiary these costs relate. Here are some examples:

- A Payroll Processor is processing the payroll for Black Hills Power. The labor costs incurred in processing payroll are specifically associated with an identified subsidiary. Therefore, this would be a direct cost.
- An Internal Auditor travels to Denver to complete audits for Colorado Independent Power Production and Black Hills Exploration and Production. The time associated with completing the audits would be charged to each company based on the time worked for each specific company project. The travel expenses should be split equally or on a pro rata share based on days worked. The Human Resources department incurs costs to bring an employment candidate on-site to Gillette for an interview with Wyodak Resources. These travel costs incurred in bringing the employee in for the interview are specifically associated with an identified subsidiary. Therefore, this would be a direct cost.
- A Help Desk technician orders a replacement computer monitor for an employee at Black Hills Power. This hardware cost incurred is specifically associated with an identified subsidiary. Therefore, this would be a direct cost.

Indirect costs are those costs that are not associated with an identified subsidiary. This means that the costs indirectly support all companies or directly support the operation of the Service Company. In other words, costs that would be directly charged to the Service Company using the definition and examples above would be classified as indirect costs. Here are some examples:

- The Internal Audit department is completing a BHC consolidated financial statement audit. Since all entities indirectly affect the financial statements of BHC consolidated, this charge would be considered an indirect cost.
- An Environmental representative attends an industry training event). This charge cannot be directly attributable to any specifically identified company; therefore, this charge would be considered an indirect cost

- A Help Desk technician orders a replacement computer monitor for an employee of the Service Company. This hardware cost incurred is specifically associated with the Service Company. Therefore, this would be an indirect cost.

It is important to consider two things when determining if a cost is a direct cost or an indirect cost: (1) Can the costs that are coded to a specific company or group of companies be substantiated; and (2) Can it be substantiated that a utility-based entity is not subsidizing the operations of non-utility based company with the time and expenses that have been charged to them. A certain level of judgment will be involved when deciding whether a particular cost should be directly charged or indirectly allocated.

There are certain costs that will always be considered either direct or indirect costs. Below is a list of significant Service Company expenses that follow these rules:

Always considered direct costs:
- Capitalized costs for non-BHSC projects (including capitalized labor)
- Corporate development project costs
- Retiree healthcare costs

Always considered indirect costs:
- Board of Directors' fees and expenses
- General Office rent
- Depreciation of BHSC assets
- Directors' and officers' insurance
- Investor relations expenses
- Shareholder expenses
- Intercompany interest expense and income

Transaction Coding

The Service Company uses an accounting software system to accumulate and distribute both direct costs and indirect costs. It is important to have costs properly classified as direct or indirect. Direct costs will be directly charged to the subsidiaries, while indirect costs will be allocated to the subsidiaries using pre-defined allocation factors. Below is a description of the coding.

______ -- ________ -- _________ -- ________ -- _______ -- ________

GL BU **OpUnit** **Dept.** **Acct.** **Resource** **Product**

General Ledger Business Unit (GLBU):

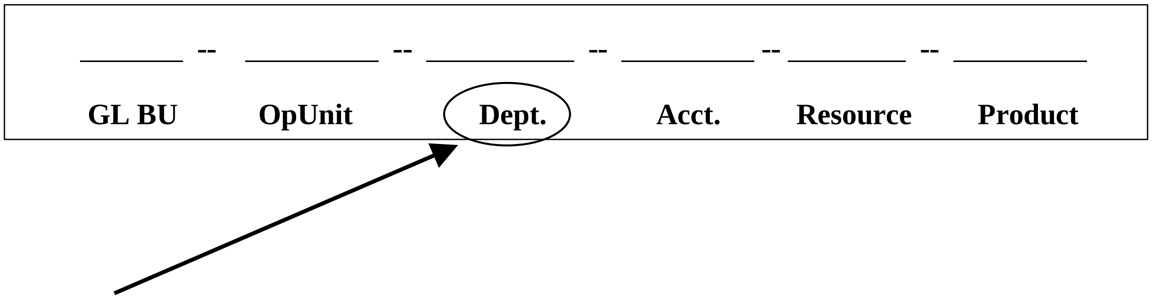
- Five (5) character numeric field.
- The GLBU field is used to identify the company that will be receiving the charges.
- The GLBU field is required on all accounting transactions.
- The GLBU field will default when the Operating Unit (OpUnit) is entered.

______ -- ________ -- _________ -- ________ -- _______ -- ________

GL BU **OpUnit** **Dept.** **Acct.** **Resource** **Product**

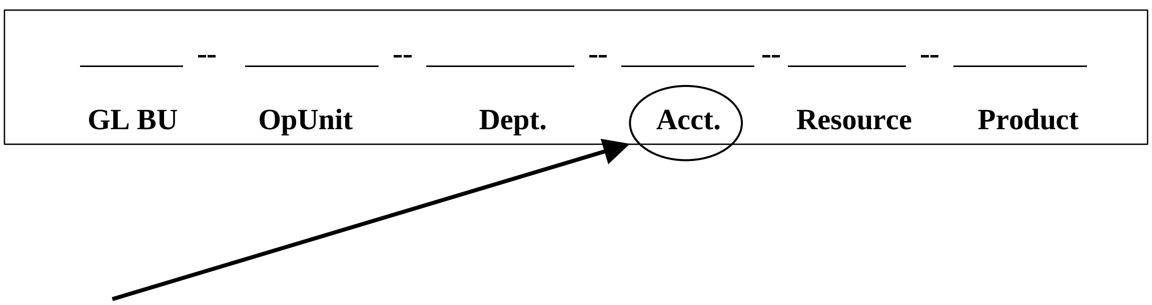
Operating Unit (OpUnit):

- Six (6) character numeric field.
- The OpUnit field is used to identify the account code block as either a direct cost or an indirect cost.
- If the cost is a direct cost, the OpUnit field will be populated using the OpUnit code for the company being directly charged.
- If the cost is an indirect cost, the OpUnit field will be populated using one of the BHSC OpUnit's. Indirect costs also include costs directly related to the Service Company.



Department (Dept):

- Four (4) character numeric field.
- The Dept field is used to identify where the cost(s) originated.
- The Dept field is required on all income statement and capital transactions.
- Every department is assigned to a GLBU.



Account (Acct)

- Six (6) character numeric field.
- The Account field is required on all accounting transactions.
- All companies will generally use the same Chart of Accounts although some values will be specific to certain companies.

GL BU -- OpUnit -- Dept. -- Acct -- Resource -- Product

Resource:

- Four (4) character numeric field.
- A Resource is used to identify types of costs.
- The Resource field is required on all income statement and capital accounting transactions.

GL BU -- OpUnit -- Dept. -- Acct -- Resource -- Product

Product:

- Three (3) character numeric field.
- A Product code is used to identify business lines.

GL BU -- OpUnit -- Dept. -- Acct -- Resource -- Product -- Work Order

Work Order:

- Eight (8) character numeric field.

- Represents the collection of costs to allow the monitoring of a job or group of costs.
- The Work Order field is required on all construction work in progress transactions

Timekeeping

All Service Company employees are required to complete a timesheet for each two week pay period. Timesheets of appropriate employees must be approved by a supervisor.

Employees must complete the code block, as previously discussed, for each time record. The timesheet will default the department and resource. However, the employee is responsible for providing the remainder of the code block. Employees are encouraged to enter their time in one half hour increments, although they may use smaller increments if they so choose.

Loadings

Certain benefits that are provided to employees become an inherent cost of labor. To account for these benefits and allow for them to be charged to the appropriate subsidiary, they become part of a loading rate that is added on to each payroll dollar.

The loading rates are calculated at the beginning of the year based on budgeted benefit expenses and budgeted labor. Benefit costs and loading ratesare reviewed, and updated as needed. Below is a list of components of the loading rates:

General labor loadings:

- Compensated Absences: including but not limited to PTO, Holiday, Jury duty, Funeral pay, United Way day, Short-term Disability and Annual Physical appointment.
- Payroll Taxes: including but not limited to FICA, FUTA SUTA and city taxes
- Employee Benefits: including but not limited to health and medical, 401K match and fees, Pension, Retiree healthcare and associated fees and Pension audit fees
- Incentives: including but not limited to Non-officer incentive plans, Restricted Stock and Stock Option expense

Supplemental loadings:

- Officer short term incentive plans
- Officer supplemental retirement
- Officer performance plan

Loadings calculated on payroll are based on estimated benefit costs, therefore, differences between actual benefits will be inherent to this process. After the difference is calculated and reviewed for reasonableness, it is recorded to a separate department, and indirectly allocated to Black Hills Corporation subsidiaries.

Allocation Factors

As previously stated, Service Company costs are either directly charged to a subsidiary, or indirectly allocated when the cost is not associated with a specific subsidiary. Indirect costs are allocated using one of several pre-defined allocation factors. Each department has been assigned one of these allocation factors. All indirect costs of that department are then allocated using that factor. When determining which allocation factor should be assigned to each department, a factor is selected based on the specific cost driver of that department. For instance, the expenses incurred by a Human Resources department are primarily related to their support of all company employees. In this example, the cost driver for the Human Resources department indirect costs is employees. Therefore, their indirect costs will be allocated based upon the Employee Ratio.

For certain departments, a specific cost driver may not be clearly identifiable or the driver may not be cost effective to compute on a continuing basis. In these instances, a three-pronged general allocation factor is used, which is referred to as the Blended Ratio. This ratio equally weights three different general ratios: Gross Margin, Asset Cost (limited to gross PP&E), and Payroll Dollars. These factors were chosen to be included in the Blended Ratio because they best allocate costs based on the diverse nature of BHC operations.

In addition, some departments utilize a Holding Company Blended Ratio. The difference between the Blended Ratio and the Holding Company Blended Ratio is that the Holding Company Blended Ratio allocates a percentage of costs to BHC Holding Company. For example, the Corporate Governance department will allocate indirect costs using the Holding Company Blended Ratio because certain costs incurred, such as New York Stock Exchange fees and Board of Directors costs, relate to both the Holding Company and the subsidiary companies.

One additional item to note is that pooled benefits, primarily health care costs, are allocated differently due to the pooling method for benefits such as self-insured health care. Black Hills Corporation has chosen to pool certain benefit costs and spread the risk amongst all subsidiaries equally. All pooled benefit costs of BHC are paid by the Service Company and allocated to subsidiaries based on employee counts.

Appendix 2 includes a list of all allocation factors, including a brief description of the factor, the basis for the calculation of the factor, and the departments to which that factor has been assigned. Asset factors and employee count factors are calculated as of period-end dates, while revenue and expense factors are calculated for twelve months ended as of period-end dates.

Changing Allocation Factors

Allocation factors are set at the first of the year, based upon financial information from the prior year ending December 31st. Assets, utility assets, employee counts, and power generation capacity are based on values as of the previous period ending December 31st. Gross margin, utility gross margin, payroll dollars, and utility payroll dollars are based on values for the 12 months ended December 31st.

Certain events may occur during the year that are deemed to be significant to Black Hills Corporation that will require corresponding adjustments be made to the allocation factors. Examples of these types of events include acquisitions, divestitures, new generation, significant change in asset base, significant staffing changes or new, significant revenue streams.

When these events occur, indirect allocation factors will be adjusted. When adjusting allocation factors, it is the policy of the Service Company to not recalculate all allocation factors. Rather, allocation factors will be adjusted with pro forma adjustments for the subsidiary with a significant change in a specific allocation factor base. For example, if an acquisition occurs during the middle of the year, pro forma values will be loaded. Asset values at the time of the acquisition would be used, as well as pro forma gross margin and payroll dollars for a 12 month period. It should be noted that estimations may be required, especially when significant additions or changes are expected as a result of the acquisition.

It should also be noted that asset values, gross margin, and payroll dollars for the other companies will not be changed. However, the ratios will change because the base against which the ratios are calculated will change. Subsidiary companies would see decreased ratio values with acquisitions, and increased ratio values with divestitures. Changes will be effective as of the beginning of the month following the significant event, and will apply to all transactions for the month.

Subsidiary Payment for Direct and Indirect Charges

It is the policy of the Service Company to insure payments are made by the subsidiary companies for direct and indirect charges. All payments for direct and indirect charges must be remitted to the Service Company by the end of the following month. The

Service Company will monitor payments received during the month to insure that all subsidiary companies make payment in a timely manner.

Allocating Fixed Assets

The Service Company maintains certain fixed assets that are used by and benefit multiple Black Hills Corporation subsidiaries. These fixed assets primarily consist of computer hardware and software that form the corporate-wide information technology network. Because these fixed assets support multiple Black Hills Corporation subsidiaries, they are allocated to the appropriate subsidiaries monthly as part of the month-end close process, along with the allocation of these assets' accumulated depreciation. Construction Work in Process balances are not allocated.

Allocated assets and accumulated depreciation are maintained in separate general ledger accounts at the subsidiary level so that they are not intermingled with regular subsidiary fixed assets, and for ease of reconciliation.

The allocation factor used for fixed assets and accumulated depreciation is the Blended Ratio, except as otherwise noted. Depreciation expense is also allocated using the Blended Ratio.

Appendix 1 – BHSC Departments

The following departments are included in BHSC as of 01/01/2013 and are subject to changes as required to support evolving business requirements.

SC-ACCOUNTING SYSTEMS (4700)

Description: Maintains the corporate- wide accounting systems of Black Hills Corporation, most notably the general ledger and financial statement preparation systems. (Blended)

SC-DISBURSEMENTS (4701)

Description: Processes payments to vendors and prepares 1099s and applicable documentation for the majority of Black Hills Corporation subsidiaries. Also, processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting and compliance reports for Black Hills Corporation and its subsidiaries. (Blended)

SC-CORP DEVELOPMENT (4702)

Description: Facilitates the development of the corporate strategy, prepares strategic plans, and evaluates potential business opportunities. Department also assists various subsidiaries with financial analysis and special projects. (HoldCo Blended)

SC-CORP GOV AND SHAREHOLDER SERV (4703)

Description: Develops and enforces corporate governance policies and procedures in accordance with applicable laws and regulations. Provides oversight of compliance with Securities and Exchange Commission rules and regulations. Oversees the administrative duties to the Board of Directors. Provides various recordkeeping and administrative services related to shareholder services. Assists in the administration of equity-based compensation plans. (HoldCo Blended)

SC-TAX (4704)

Description: Prepares quarterly and annual tax provisions of all Black Hills Corporation subsidiaries. Maintains and reconciles all current and deferred income tax general ledger accounts. Prepares tax filings and ensures compliance with applicable laws and regulations. Oversees various tax planning projects. (Blended)

SC-CREDIT AND RISK (4705)

Description: Provides risk management, risk evaluation, and risk analysis services. Provides support to the Executive Risk Committee. Evaluates contract risks. (Blended)

SC-LEGAL - CORPORATE (4706)

Description: Provides legal counsel and services related to general business operations, including labor and employment law, finance, litigation, contracts, utility rates and regulation, financial reporting, Securities and Exchange Commission, Federal Energy Regulatory Commission and other state and federal compliance, environmental matters, real estate and other legal matters. Oversees the hiring and administration of external counsel. Provides legal support to various corporate development projects. (Blended)

SC-CORPORATE AFFAIRS (4708)

Description: Provides oversight to Public Relations, Marketing, Governmental Affairs, Regulatory Affairs and Regulatory Services/Resource Planning for all Black Hills Corporation and its subsidiaries. (Blended)

SC-ENVIRONMENTAL SERVICES (4709)

Description: Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental clean-up projects. Obtains permits to support the business operations of Black Hills Corporation and its subsidiaries. (Asset)

SC-EXECUTIVE MGMT (4710)

Description: Provides overall oversight of Black Hills Corporation and its subsidiaries. Provides the Board of Directors information for decision making purposes. (HoldCo Blended)

SC-SAFETY (4711)

Description: Develops and implements safety planning activities and provides employee safety education. Administers the corporate safety program. Assists with compliance with DOT, OSHA, and MSHA regulations. (Employee)

SC-FINANCE AND TREASURY (4712)

Description: Coordinates activities related to securities issuance, including maintaining relationships with financial institutions, debt holders, rating agencies, equity analysts and equity investors. Performs accounting, cash management, debt compliance, and investing activities. Monitors capital markets to support financial planning for all subsidiaries. Oversees the administration of corporate pension and 401(k) plans. (HoldCo Blended)

SC-FINANCIAL REPORTING (4713)

Description: Oversees the corporate consolidation of subsidiary financial statements. Prepares monthly internal financial reports for management. Prepares quarterly and annual financial reports to the Securities and Exchange Commission, financial statements to banks and quarterly and annual financial statements filed wtih FERC. Researches emerging accounting issues and assists with the compliance of new accounting rules and regulations. (HoldCo Blended)

SC-BUDGET AND FORECAST (4714)

Description: Oversees the accumulation of subsidiary financial budgets and forecasts. Provides the consolidation of the corporate wide- budget and forecast. Guides the preparation of strategic plans. (Blended)

SC-GENERAL ACCOUNTING (4715)

Description: Provides management and administrative support for accounting and finance functions of the Company's regulated and non-regulated businesses including external audit coordination. (Blended)

SC-ACCOUNTING-CENTRAL SERVICES (4716)

Description: Maintains the accounting records for Black Hills Service Company and Black Hills Corporation. Provides oversight of Accounts Payable, Payroll, and Property Accounting departments. (Blended)

SC-ACCOUNTING-GENERATION SERV (4717)

Description: Provides general ledger accounting to non-regulated generation facilities and accounting support to all generation facilities. (Generation Capacity)

SC-HUMAN RESOURCES CORP (4718)

Description: Provides general Human Resources support services through the administration of policies for all facets of Human Resources, including employee relations, labor relations, talent management, recruiting and employment staffing, compensation and benefits administration and state/federal regulation compliance. (Employee)

SC-HUMAN RESOURCES REGULATED (4720)

Description: Provides general Human Resources support services to the subsidiaries through the administration of policies and labor contracts for all facets of Human Resources, including employee relations, labor relations, talent management, recruiting and employment staffing, compensation and benefits administration. (Employee)

SC-COMPENSATION AND BENEFITS (4721)

Description: Administers policies related to compensation and benefits. Oversees the self-insured medical benefits plans and other pooled benefits and provides support to the third party administrators of the plans. (Employee)

SC-ORGANIZATIONAL DEVELOPMENT AND TRAINING (4722)

Description: Provides for employee and leadership development, succession planning, performance management, goal alignment, employee engagement, strategic workforce planning, talent assessment and general HR support for Black Hills Corporation and its subsidiaries. (Employee)

SC-ENGINEERING ROTATION PROGRAM (4723)

Description: Provides a rotation program to develop staff for critical need areas within Black Hills Corporation and its subsidiaries. (Blended)

SC-INSURANCE (4724)

Description: Facilitates physical risk management strategies through the purchase and evaluation of various types of insurance coverage. Provides claims management services. (Blended)

SC-INTERNAL AUDIT (4725)

Description: Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Oversees the Sarbanes Oxley compliance efforts. (Blended)

SC-IN-HOUSE CREATIVE SOLUTIONS (4726)

Description: Provides program for effective, measured, and coordinated advertising. Manages, develops and implements communication channels to maintain effective communications with stakeholders. Designs and develops communication materials. (Blended)

SC-POWER DELIVERY MGMT (4728)

Description: Performs resource planning, power delivery management, strategic planning, and construction management for the corporation's power generation assets. (Generation Capacity)

SC-PROPERTY ACCOUNTING (4729)

Description: Maintains the accounting records for property, plant and equipment for the majority of subsidiaries of the corporation. Assists in compliance with regulatory accounting requirements as it relates to property. Prepares various operating and financial reports for management. (Asset)

SC-RECORDS MGMT (4730)

Description: Administers and maintains the records retention policies and procedures of the corporation. Manages and maintains the content management software. (Blended)

SC-SUPPLY CHAIN MGMT (4731)

Description: Develops strategies and provides general oversight to Facilities, Contract Management, Strategic Sourcing, Procurement, Fleet Services, Materials Management and Supplier Diversity departments. (Blended)

SC-CONTRACTS MGMT (4732)

Description: Manages contracts, including drafting, negotiating, reviewing and interpreting contracts. (Blended)

SC-STRATEGIC SOURCING (4733)

Description: Executes the procurement process including, purchasing activities, managing vendor relationships, and issue resolution and tracking and expediting orders. (Blended)

SC-FLEET SERV (4734)

Description: Manages fleet expense cards, fleet contracts, vehicle purchasing, replacement, disposal, licensing/registration and titling. Advises on vehicle maintenance and repairs, alternative fuel selections and implementations. (Blended)

SC-FACILITIES (4736)

Description: Provides facility, construction, and real estate management services for corporate-wide facilities. Supports disaster recovery and business continuation planning. (Blended)

SC-GOVERNMENTAL AFFAIRS (4741)

Description: Advances corporate objectives by initiating, influencing, monitoring, and researching government legislation and policies. Acts as a liaison with legislators and other governmental officials. Maintains relationships with federal, state and other governmental bodies. (Blended)

SC-IT ADMINISTRATION (4742)

Description: Provides guidance, governance, and strategic planning to the overall information technology operations. (Blended)

SC-IT BUSINESS APPLICATIONS-FIN AND HR SYSTMS (4743)

Description: Manages, maintains, and enhances the financial and human resource related business applications of the company. (Blended)

SC-IT BUSINESS APPLICATIONS-REGULATED (4744)

Description: Manages, maintains, and enhances business applications within the utility companies. (Utility Blended)

SC-IT BUSINESS APPLICATIONS-WEB SERV SUPP (4745)

Description: Manages, maintains, and enhances the web-based service business applications of the company. (Blended)

SC-IT BUSINESS APPLICATIONS-WHOLESALE AND ENTERPRISE (4746)

Description: Manages, maintains, and enhances the wholesale and enterprise-wide business applications of the company. (Blended)

SC-IT INFRASTRUCTURE SERV (4747)

Description: Manages, maintains, and enhances data center operations, infrastructure servers, storage, system software, enterprise architecture, and corporate databases. (Blended)

SC-IT COMMUNICATIONS (4748)

Description: Manages and supports the data and voice communication needs for the company. Provides telecommunication expense management services. (Blended)

SC-IT USER SERVICES (4749)

Description: Provides technology support services for the company, including field services. (Blended)

SC-IT COMPLIANCE (4751)

Description: Responsible for internal and external audit compliance, disaster recovery, change management and legal compliance related to technology. (Blended)

SC-MATERIALS MGMT (4752)

Description: Manages inventory, obsolescence and scrap. Ensure availability of proper materials. Pull, restock and stage materials. (Blended)

SC-CONTINIOUS IMPROVEMENT (4753)

Description: Helps identify solutions to improve work processes, maximize business performance and add value for customers and stakeholders. (Blended)

SC-GENERATION PLANT OPERATIONS (4754)

Description: Operates and manages the generation for BHCOE and BHCIPP. (NamePlate Generation Capacity)

SC-IT HELPDESK / TECHNOLOGY INTEGRATION (4755)

Description: Provides IT telephone support, technology training and technology integration services. (Blended Ratio)

SC-CPGS PLANT OPERATIONS (4756)

Description: Operates and manages the new generation for the Cheyenne Prairie Generation Station. (NamePlate Generation Capacity)

SC-PROCUREMENT (4760)

Description: Executes the procurement process including, purchasing activities, managing vendor relationships, and issue resolution and tracking and expediting orders. (Blended)

SC – ASSET BLENDED (4793)

Description: Records depreciation for the Service Company assets. (Blended)

SC-BENEFIT POOLED (4794)

Description: Records pooled benefit costs, primarily related to health and welfare for Black Hills Corporation and its subsidiaries. (Employee)

SC-ACCOUNTING ACCRUAL ENTRIES (4795)

Description: Records accrual of certain charges not related to specific departments or not significant enough to allocate to each department. (Blended)

SC-BENEFITS LOADING (4796)

Description: Records overhead benefit costs loaded to labor costs (Blended)

Appendix 2 – Allocation Factors

Asset Cost Ratio – Based on the total cost of assets as of December 31 for the prior year, the numerator of which is for an applicable BHC subsidiary and the denominator of which is for all applicable BHC subsidiaries. Assets are limited to property, plant, and equipment, and include construction or work in process. Assets are also reported at their FERC value, meaning that assets for the utility subsidiaries will not include any adjustments that are required to bring their FERC financial statements into compliance with GAAP. FERC requires that acquired fixed assets be recorded at their gross value with accumulated depreciation, while GAAP requires that acquired fixed assets be recorded at their net book value. An adjustment journal entry is used to eliminate the gross-up of cost and accumulated depreciation for preparation of GAAP financial statements, but this adjustment is not factored into the calculation of the Asset Cost Ratio.

The Environmental Services and Property Accounting departments utilize this ratio, and it is a component in the Blended Ratio and the Holding Company Blended Ratio.

Gross Margin Ratio – Based on the total gross margin for the prior year ending December 31, the numerator of which is for an applicable BHC subsidiary and the denominator of which is for all applicable BHC subsidiaries. Gross margin is defined as revenue less cost of sales. Certain intercompany transactions may be excluded from gross margin if they would not have occurred if the revenue relationship was with a third party instead of a related party.

No departments utilize this ratio, but it is a component in the Blended Ratio and the Holding Company Blended Ratio.

Payroll Dollars Ratio – Based on the total payroll dollars for the prior year ending December 31, the numerator of which is for an applicable BHC subsidiary and the denominator of which is for all applicable BHC subsidiaries. Payroll dollars include all bonuses and compensation paid to employees, but do not include items that are only included on an employee's W-2 for gross-up and income tax purposes, such as life insurance premiums over $50,000.

No departments utilize this ratio, but it is a component in the Blended Ratio and the Holding Company Blended Ratio.

Blended Ratio – A composite ratio comprised of an average of the Asset Cost Ratio, the Payroll Dollars Ratio, and the Gross Margin Ratio. These factors are equally weighted. This factor is sometimes referred to as the general allocation factor.

Departments that utilize this ratio include Accounting Systems, Accounts Payable, Tax, Credit and Risk, General Accounting, Insurance, Internal Audit, Legal, Corporate Affairs, Budget and Forecast, General Accounting, Accounting-Central Services, Engineering

Rotation Program, Insurance, Internal Audit, In-House Creative Solutions, Records Management, Supply Chain Management, Contract Management, Strategic Sourcing, Fleet Services, Facilities, Governmental Affairs, Information Technology Administration, Information Technology Business Applications Wholesale and Enterprise, Information Technology Business Applications Web Service Support, Information Technology Business Applications Financial and HR Systems, Information Technology Infrastructure Services, Information Technology Communications, Information Technology User Services, Corporate Security, Information Technology Compliance, Materials Management, Continuous Improvement, Information Technology Helpdesk / Technology Integration, Procurement, Assets Blended, Accounting Accruals, Benefits and BHSC portion of the Rapid City Plant Street Facility, Midlands Data Facility and Bellevue Data Center Facility.

Holding Company Blended Ratio – 5% of costs allocated to the Holding Company, with the remaining 95% of costs allocated using a composite ratio comprised of an average of the Asset Cost Ratio, the Payroll Dollars Ratio, and the Gross Margin Ratio. These factors are equally weighted.

Departments that utilize this ratio include Corporate Development, Corporate Governance and Shareholder Services, Executive Management, Finance and Treasury and Financial Reporting.

Employee Ratio – Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable BHC subsidiary and the denominator of which is for all applicable BHC subsidiaries.

Departments that utilize this ratio include Safety, Human Resources Corp., Human Resources Regulated, Compensation and Benefits, Organizational Development and Training, and Payroll. Health and welfare costs for BHC will be in a pool and allocated to subsidiaries based on the Employee Ratio.

Power Generation Capacity Ratio – Based on the total power generation capacity at the end of the prior year ending December 31, the numerator of which is for an applicable BHC subsidiary and the denominator of which is for all applicable BHC subsidiaries. Power generation includes capacity in service and capacity under construction.

Departments that use this ratio include Power Delivery Management and Accounting-Generation Services.

Utility Asset Cost Ratio – Based on the total cost of utility assets as of December 31 for the prior year, the numerator of which is for an applicable BHC utility subsidiary and the denominator of which is for all applicable BHC utility subsidiaries. Utility assets are limited to property, plant, and equipment, and include construction or work in process. Assets are also reported at their FERC value, meaning that assets for the utility subsidiaries will not include any adjustments that are required to bring their FERC financial statements into compliance with GAAP. FERC requires that acquired fixed assets be recorded at their gross value with accumulated depreciation, while GAAP requires that acquired fixed assets be recorded at their net book value. An adjustment journal entry is used to eliminate the gross-up of cost and accumulated depreciation for preparation of GAAP financial statements, but this adjustment is not factored into the calculation of the Utility Asset Cost Ratio.

No departments utilize this ratio, but it is a component in the Utility Blended Ratio

Utility Employee Ratio – Based on the number of utility employees at the end of the prior year ending December 31, the numerator of which is for an applicable BHC utility subsidiary and the denominator of which is for all applicable BHC utility subsidiaries.

No departments currently utilize this ratio.

Utility Gross Margin Ratio – Based on the total utility gross margin for the prior year ending December 31, the numerator of which is for an applicable BHC utility subsidiary and the denominator of which is for all applicable BHC utility subsidiaries. Utility gross margin is defined as revenue less cost of sales. Certain intercompany transaction may be excluded from utility gross margin if they would not have occurred if the revenue relationship was with a third party instead of a related party.

No departments utilize this ratio, but it is a component in the Utility Blended Ratio.

Utility Payroll Dollars Ratio – Based on the total utility payroll dollars for the prior year ending December 31, the numerator of which is for an applicable BHC utility subsidiary and the denominator of which is for all applicable BHC utility subsidiaries. Utility payroll dollars include all bonuses and compensation paid to employees, but do not include items that are only included on an employee's W-2 for gross-up and income tax purposes, such as life insurance premiums over $50,000.

No departments utilize this ratio, but it is a component in the Utility Blended Ratio.

Utility Blended Ratio – A composite ratio comprised of an average of the Utility Asset Cost Ratio, the Utility Payroll Dollars Ratio, and the Utility Gross Margin Ratio. These factors are equally weighted.

The IT Business Applications Regulated department utilizes this ratio.

Nameplate Generation Capacity Ratio – Based on the total facility's power generation capacity at the end of the prior year ending December 31, the numerator of which is for an applicable BHC subsidiary and the denominator of which is for all applicable BHC subsidiaries. Nameplate generation includes capacity in service and capacity under construction at the facility.

The Generation Plant Operations and CPGS Plant Operations departments utilize this ratio. (should the Generation Plant Operations department be re-named to PAGS Plant Operations? If so, this will need to be updated in multiple places.

Square Footage Ratio – The total square footage of a given facility, the numerator of which is for an applicable BHC subsidiary and the denominator of which is for all applicable BHC subsidiaries.

The Rapid City Plant Street Facility and the Denver Office Facility utilize this ratio.

Black Hills Utility Holdings, Inc.

Cost Allocation Manual

Effective Date: July 14, 2008

Amended: August 1, 2009

Amended: January 1, 2011

Amended: January 1, 2012

Amended: January 1, 2013

Amended: December 1, 2013

Black Hills Utility Holdings, Inc. Cost Allocation Manual

Table of Contents

Introduction

The purpose of this cost allocation manual is to document the allocation processes of Black Hills Utility Holdings, Inc. ("BHUH"), from recording the original transaction through the allocation of costs to entities receiving services from BHUH. Various topics to be addressed include the organization of BHUH, the recording of transactions, calculating and assigning allocation ratios, and recording allocation transactions.

BHUH began formal operations in July 2008. The company was formed in anticipation of the purchase of certain gas and electric utility operating companies from Aquila, Inc. BHUH is a wholly owned subsidiary of Black Hills Corporation ("BHC"). BHUH is the parent company of each of the five acquired Aquila operating companies. In addition, BHUH also supports the operations of the five acquired Aquila operating companies and other utility and utility like operating companies, together the "operating companies". These costs are allocated to the operating companies requesting service using formal cost allocation methodologies. Departments that provide support services to the five acquired Aquila operating companies as well as other Black Hills Corporation subsidiaries are held at Black Hills Service Company, LLC ("BHSC"). BHSC cost allocation methodologies are discussed in a separate cost allocation manual.

BHUH Organization

BHUH is organized into departments based upon the services that those departments provide to the operating companies. A list of each department, as well as a brief description of the services they provide, is attached hereto as Appendix 1.

Direct Costs versus Indirect Costs

A key issue in distributing BHUH costs is distinguishing between direct costs and indirect costs. The account coding will change depending on whether the cost is a direct or indirect cost. Below is a summary of each of these types of costs and examples of these costs.

Direct costs are those costs that are specifically associated with an identified operating company. This means that it is known exactly to which operating company these costs relate. Here are some examples:

- Advertising is prepared for a new customer information and instructional advertising campaign in the state of Nebraska. The advertising costs incurred are specifically associated with an identified operating company. Therefore, this would be a direct cost.

- The Vice President of Utilities attends a meeting on the proposed budget for the state of Iowa. The labor costs incurred in attending this meeting are specifically associated with an identified operating company. Therefore, this would be a direct cost.

- A trainer from Gas Engineering travels to various Black Hills Kansas Gas field offices to conduct training. These travel costs are specifically associated with an identified operating company. Therefore, this would be a direct cost.

Indirect costs are those costs that are not associated with an identified operating company. This means that the costs indirectly support all companies or directly support the operation of BHUH. In other words, costs that would be directly charged to BHUH using the definition and examples above would be classified as indirect costs. Here are some examples:

- Advertising is prepared for all customers to inform them of changes to electronic payment processes. These advertising costs incurred apply to all operating companies. Therefore, this would be an indirect cost.

- The Vice President of Utilities attends a meeting to present the consolidated budget for all gas utilities to the Board of Directors. The labor costs incurred in attending this meeting are not specifically associated with an identified operating company. Therefore, this would be an indirect cost.

- A trainer from Gas Engineering travels to Rapid City to present a training program to operating company executives. These travel costs are specifically associated with BHUH. Therefore, this would be an indirect cost.

It is important when determining if a cost is a direct cost or an indirect cost to consider two things: (1) Can the costs coded to a specific operating company or group of operating companies be substantiated, and (2) Can it be substantiated that a utility-based subsidiary is not subsidizing the operations of a non-utility based subsidiary with the time and expenses that have been charged to them. A certain level of judgment will be involved when deciding whether a particular cost should be directly charged or indirectly allocated.

There are certain costs that will always be considered either direct or indirect costs. Below is a list of significant BHUH expenses that follow these rules:

Always considered direct costs:

- Capitalized costs for non-BHUH projects (including capitalized labor)
- Retiree healthcare costs

Always considered indirect costs:

- Depreciation of BHUH and BHSC assets
- Intercompany interest expense and income related to the BHUH balance payable or receivable from the Utility Money Pool

Transaction Coding

The Holding Company uses an accounting software system to accumulate and distribute both direct costs and indirect costs. It is important to have costs properly classified as direct or indirect. Direct costs will be directly charged to the subsidiaries, while indirect costs will be allocated to the subsidiaries using pre-defined allocation factors. Below is a description of the coding.

_______ --	_________ --	__________ --	_________ --	________ --	_________
GL BU	**OpUnit**	**Dept.**	**Acct.**	**Resource**	**Product**

General Ledger Business Unit **("GLBU"):**

- Five (5) character numeric field.
- The GLBU field is used to identify the company that will be receiving the charges, either as a direct cost or an indirect cost.
- The GLBU field is required to be populated on all accounting transactions
- The GLBU field will default based on the operating unit (Op Unit), as described below.

_______ --	_________ --	__________ --	_________ --	________ --	_________
GL BU	**OpUnit**	**Dept.**	**Acct.**	**Resource**	**Product**

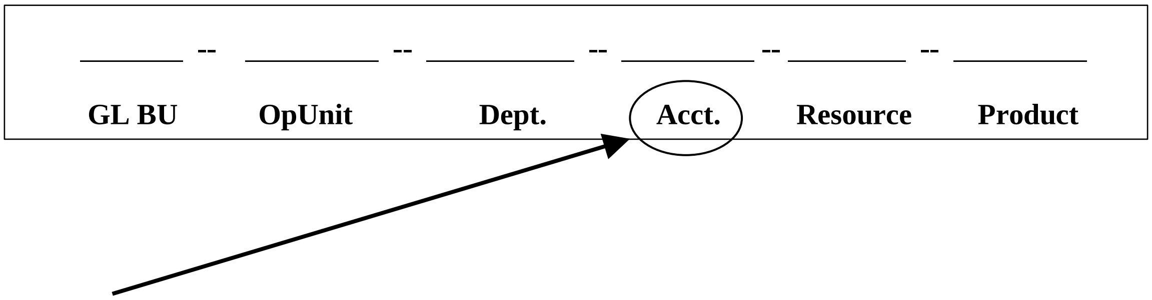
Operating Unit (“OpUnit”):

- Six (6) character numeric field.
- The Op Unit field is used to identify the account code block as either a direct cost or an indirect cost.
- If the cost is a direct cost, the Op Unit field will be populated using an Op Unit at the specific GLBU being charged.
- The Op Unit field will be populated using one of the BHUH Op Units for indirect costs. Indirect costs also include costs from other areas of the company that are directly related to the Utility Holding Company.

_______ --	_________ --	__________ --	_________ --	________ --	_________
GL BU	**OpUnit**	**Dept.**	**Acct.**	**Resource**	**Product**

Department **(“Dept.”):**

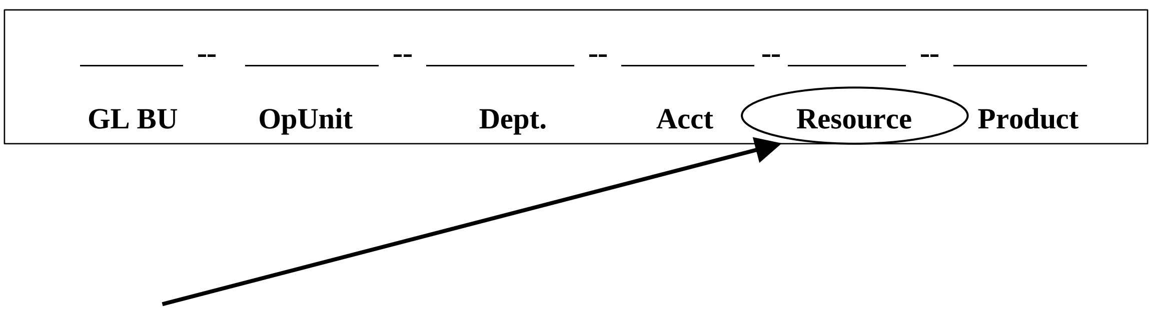
- Four (4) character numeric field
- The department field is used to identify where the cost(s) originated
- The department field is required on all income statement and capital transactions
- Every department is assigned to a GLBU



Account **("Acct."):**

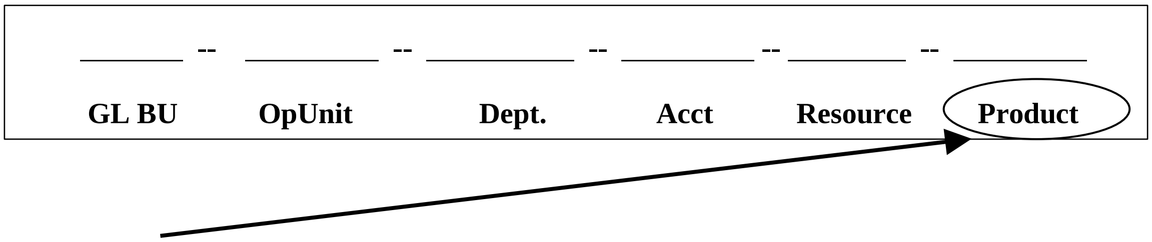
- Six (6) character numeric field
- The account field is required on all accounting transactions

All companies will generally use the same Chart of Accounts although some values will be specific to certain companies.



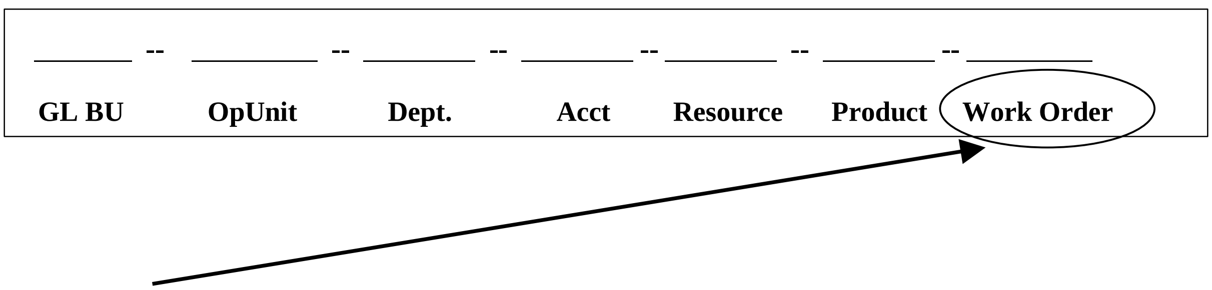
Resource:

- Four (4) character numeric field
- A Resource is used to identify types of costs
- The resource field is required for all income statement and capital accounting transactions



Product:

- Three (3) character numeric field
- A Product is used to identify business lines
- Examples of the product line include electric, gas, and non-regulated



Work Order:

- Eight (8) character numeric field
- Represents the collection of costs to allow the monitoring of a job or group of costs
- The work order field is required on all construction work in progress transactions

Timekeeping

All BHUH employees are required to complete a timesheet for each two week pay period. Timesheets of appropriate employees must be approved by a supervisor.

Employees must complete the coding string, as previously discussed, for each time record. The timesheet will default the department and resource. However, the employee is responsible for providing the remainder of the code block. Employees are encouraged to enter their time in one half hour increments, although they may use smaller increments if they so choose.

Loadings

Certain benefits that are provided to employees become an inherent cost of labor. To account for these benefits and allow for them to be charged to the appropriate subsidiary, they become part of a loading rate that is added on to each payroll dollar.

The loading rates are calculated at the beginning of the year based on budgeted benefit expenses and budgeted labor. Benefit costs and loading rates are reviewed, and updated as needed. Below is a list of components of the loading rates:

General loadings:

- Compensated Absences: including but not limited to PTO (Paid Time Off), Holiday, Jury duty, Funeral pay, United Way day, Short-term Disability and Annual Physical appointment.
- Payroll Taxes: including but not limited to FICA, FUTA SUTA and city taxes.
- Employee Benefits: including but not limited to health and medical, 401K match and fees, Pension, Retiree healthcare and associated fees and Pension audit fees.
- Incentives: including but not limited to Non-officer incentive plans, Restricted Stock and Stock Option expense.

Loadings calculated on payroll are based on estimated benefit costs, therefore, differences between actual benefits will be inherent to this process. After the difference is calculated and reviewed for reasonableness, it is recorded to a separate department, and indirectly allocated to Black Hills Corporation subsidiaries.

Allocation Ratios

As previously stated, BHUH costs are either directly charged to an operating company, or indirectly allocated when the cost is not associated with a specific operating company. Indirect costs are allocated out using one of several pre-defined allocation ratios. Each department has been assigned one of these allocation ratios. All indirect costs of that department are then allocated using that ratio. When determining which allocation ratio should be assigned to each department, a ratio was selected based on the specific cost driver of that department. For instance, the expenses incurred by the Customer Service - Rapid City department are primarily related to the support of all utility customers. In this example, the cost driver for the Customer Service - Rapid City department indirect costs is the number of customers. Therefore, the indirect costs will be allocated based upon the Customer Count Ratio.

When determining how the assigned ratio should be applied, consideration is given to the operating companies or segments that are supported by the department. For instance, the Appliance Technical Training department was determined to have a cost driver of number of Service Guard customers. Therefore, the indirect costs will be allocated based on the Customer Count Ratio using Service Guard customers whereas the Customer Service – Rapid City department used in the previous example would be allocated based on the Customer Count Ratio using Regulated Utility customers.

For certain departments, a specific cost driver may not be clearly identifiable or the driver may not be cost effective to compute on a continuing basis. In these instances, a three-pronged general allocation ratio is used. This ratio equally weights three different general ratios: Gross Margin, Asset Cost, and Payroll Dollars. These ratios were chosen to be included in the Blended Allocator Ratio because they best allocate costs based on the diverse nature of BHUH operations.

A list of all allocation ratios, including a brief description of the ratio, the basis for the calculation of the ratio, and the department to which that ratio has been assigned, is attached hereto as Appendix 2.

Changing Allocation Ratios

Allocation ratios are set at the first of the year, based upon financial information from the prior year ending December 31^{st}. The ratios for Asset Cost and Customer Count are based on values as of the previous period ending December 31^{st}. The ratios for Gross Margin, Payroll Dollars, are based on values for the 12 months ended December 31^{st}.

Certain events may occur during the year that are deemed to be significant to BHUH that will require corresponding adjustments be made to the allocation ratios. Examples of these types of events include acquisitions, divestitures, new generation, significant change in asset base, significant staffing changes or new, significant revenue streams.

When these events occur, indirect allocation ratios will be adjusted. When adjusting allocation ratios, it is the policy of BHUH to not recalculate all allocation ratios. Rather, allocation ratios will be adjusted with pro forma adjustments for the subsidiary with a significant change in a specific allocation ratio base. For example, if an acquisition occurs during the middle of the year, pro forma values will be loaded. Asset values at the time of the acquisition would be used, as well as pro forma gross margin and payroll dollars for a 12 month period. It should be noted that estimations may be required, especially when significant additions or changes are expected as a result of the acquisition.

It should also be noted that asset values, gross margin, and payroll dollars for the other companies will not be changed. However, the ratios will change because the base against which the ratios are calculated will change. Operating companies would normally see decreased ratio values with acquisitions, and increased ratio values with divestitures. Changes will be effective as of the beginning of the month following the significant event, and will apply to all transactions for the month.

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Subsidiary Payment for Direct and Indirect Charges

It is the policy of BHUH to insure payments are made by the subsidiary companies for direct and indirect charges. All payments for direct and indirect charges must be remitted to BHUH by the end of the following month. BHUH will monitor payments received during the month to insure that all subsidiary companies make payment in a timely manner.

Allocating Fixed Assets

BHUH maintains certain fixed assets that are used by and benefit all operating companies. These fixed assets primarily consist of computer hardware and software and shared office facilities. Because these fixed assets support all operating companies, they are allocated monthly as part of the month-end close process, along with the allocation of these assets' accumulated depreciation. Construction Work in Process balances are not allocated.

Allocated assets and accumulated depreciation are maintained in separate general ledger accounts at the subsidiary level so they are not intermingled with regular subsidiary fixed assets, and for ease of reconciliation.

The allocation ratio used to allocate assets and accumulated depreciation will vary depending on the type of asset being allocated, and will be based on the function the asset is serving. For instance, customer service software is allocated based on the Customer Count Ratio, while general office space is allocated using the Blended Allocator Ratio.

Allocating Capitalized Inventory

The gas and electric meter shops are BHUH departments serving the utility operating companies. As meters are purchased, they are recorded as capitalized inventory (charged to plant-in-service) by BHUH, as the meters are issued out of inventory to the specific operating company those assets are transferred from BHUH to the specific utility operating companies. All unassigned gas and electric meter investment and accumulated depreciation reserve is held at BHUH, and is allocated to the applicable utilities monthly. The Customer Count Ratio is used for this allocation.

Appendix 1- BHUH Departments

UHC-GSS ADMINISTRATION (2301)

Description: Provides for the development and execution of the gas supply portfolio plans for all gas distribution operating companies and regulated power plants fueled by natural gas. This plan includes purchasing strategies for the commodity and optimization and procurement of pipeline capacity and services. (Customer Count Ratio)

UHC-ASSETS-LINCOLN CCTR/CAD (4247)

Description: The assets invested for the Computer Aided Dispatch system for Black Hills Energy. This includes capitalized and centrally located hardware and software costs to service multiple utilities. Depreciation expense and maintenance expense on this group of assets is also charged from here. (Customer Count Ratio)

UHC-ASSETS-FAME (4251)

Description: The assets invested for the Facilitated Asset Mapping Enterprise system for Black Hills Energy. This includes capitalized and centrally located hardware and software costs to serve multiple utilities. Depreciation expense on this group of assets is also charged from here. (Customer Count Ratio)

UHC-ASSETS-WORK MGMT (4257)

Description: The assets invested for the Work Management system for Black Hills Energy. This includes capitalized and centrally located hardware and software costs to serve multiple utilities. Depreciation expense on this group of assets is also charged from here. (Customer Count Ratio)

UHC-ASSETS-REG GENERATION (4258)

Description: The assets for electric utilities specifically. This includes capitalized and centrally located hardware and software costs to serve multiple electric utilities. Depreciation expense on this group of assets is also charged from here. (Customer-Regulated)

UHC-BENEFITS LOADINGS (4470)

Description: Utilized for charging out benefits, including medical costs, to the operating departments. Provided that all labor is loaded with overhead loadings, only the residual charges are to the operating companies. (Blended)

UHC-ACCOUNTING ACCRUAL ENTRIES (4474)

Description: Created to facilitate the accrual of certain charges not related to specific departments. (Blended)

UHC-ASSETS-BLENDED-ALL (4478)

Description: The assets invested and centrally located for gas and electric operating companies where the Blended Ratio is determined to be the best form of allocation. Depreciation expense on this group of assets is also charged from here. (Blended)

UHC-ASSETS-BLENDED-ELECTRIC (4479)

Description: The assets invested and centrally located for electric operating companies where the Blended Ratio is determined to be the best form of allocation. Depreciation expense on this group of assets is also charged from here. (Blended)

UHC-ASSETS-BLENDED-GAS (4480)

Description: The assets invested and centrally located for gas operating companies where the Blended Ratio is determined to be the best form of allocation. Depreciation expense on this group of assets is also charged from here. (Blended)

UHC-ASSETS-BLENDED-CUSTOMERS (4481)

Description: The assets invested and centrally located for gas and electric companies where the Customer Ratio is determined to be the best form of allocation. Depreciation expense on this group of assets is also charged from here. (Customer Count Ratio)

UHC-DESIGN ENGINEERING GAS (5105)

Description: Provides engineering support of gas transmission and distribution facilities including planning, monitoring, and analyses. (Customer-Regulated)

UHC-STANDARDS AND COMPLIANCE GAS (5106)

Description: Responsible for implementing and reporting DOT regulatory requirements, maintaining standards, and supporting GIS Smallworld mapping. (Customer-Regulated)

UHC-TRANSMISSION PLANNING (5107)

Description: Performs near and long-term (1-20 year) transmission planning to determine cost-effective transmission additions needed to reliably serve projected customer load. Performs studies in support of large customer requests and the FERC Tariff; and supports operational studies for planned outages. Provides support in meeting compliance with NERC Standards; and represents the corporation in regional and sub-regional planning groups. (Transmission)

UHC-NERC COMPLIANCE (5108)

Description: Develops, coordinates and oversees the Electric Utilities Group's compliance with mandatory North American Electric Reliability Corporation (NERC) Reliability Standards, which standards are enforceable through financial sanctions and are intended to ensure a reliable Bulk Electric System. (Transmission)

UHC-FERC TARRIFF AND COMPLIANCE (5109)

Description: Develops, coordinates, and oversees the Electric Utilities Group's compliance with the Federal Energy Regulatory Commission (FERC) requirements pertaining to electric transmission; and administers the Company's Open Access Transmission Tariff (OATT) and Open Access Same-time Information System (OASIS).Administration of the Tariff, which outlines the "rules of the road" for transmission providers, the rates we charge, and the procedures and timelines in addressing customer requests (new load, new generators, or other requests to wheel power across the system). (Transmission)

UHC-T AND D RELIABILITY CTR (5110)

Description: Operates the Company's transmission and distribution systems on a 24/7 basis; and plans and directs switching and outage restoration efforts for both emergency and planned outages. (Transmission)

UHC-NERC TRANSMISSION AND TECH SUPPORT (5111)

Description: Develops, coordinates and oversees the technical support piece of the Electric Utilities Group's compliance with mandatory North American Electric Reliability Corporation (NERC) Reliability Standards, which standards are enforceable through financial sanctions and are intended to ensure a reliable Bulk Electric System. (Transmission)

UHC-TRANSMISSION SERVICES MGMT (5112)

Description: For all three electric utilities (BHP, CLFP and Colorado Electric), Transmission Services directs the 24/7 Reliability Centers in Rapid City and Pueblo, Transmission Planning, NERC Compliance, FERC Compliance, and Transmission Tariff Administration. (Transmission)

UHC-ELEC ENGINEERING SERV (5120)

Description: Engineering Services supports transmission and distribution activities within the Electric Utilities group including engineering, distribution planning, T and D asset management, metering, substation maintenance, Vegetation Management, GIS/drafting and outage management systems. Provides Director level support to GIS support functions as defined in Dept. 5305 for both the electric and gas network operations. (Blended)

UHC-PWR SUPPLY AND RENEWABLES (5121)

Description: Provides for the planning, development, and management of power supply and renewable strategies for electric operating companies. (Blended)

UHC-ELECTRIC REGULATORY SERV (5122)

Description: Supports and manages all electric regulatory filings, rate cases, and regulatory issues. (Blended)

UHC-Technical Training(5254)

Description: Provides technical training support for gas and electric utilities. (Customer-Regulated)

UHC-GIS SUPPORT (5305)

Description: Researches, builds and implements utility software solutions for the benefit of electric and gas network operations. This department supports Smallworld GIS, STORMS work management, PowerOn outage management, Korterra line locates, and GTViewer mobile maps. (Customer Count Ratio)

UHC-GAS METERING SERV (5490)

Description: Manages and provides gas measurement support to field operations located in gas service states. (Customer-Regulated)

UHC-UTILITY FINANCIAL MGMT (5668)

Description: Assists in the compliance with regulatory and operating unit business strategy from a financial perspective. Responsible for preparation of all phases of the financial planning process including budgets, forecasts and strategic plans. Prepares various operating and financial reports for management. (Blended)

UHC-UTILITY ACCOUNTING (5670)

Description: Responsible for closing the general ledger for the utilities on a monthly basis and assists in the compliance of all accounting rules and regulations. Prepares various operating and financial reports for utility financial management. Assists the utility financial management team with monthly analysis. (Blended)

UHC-EXEC MGMT-CUST SERV (5674)

Description: Provides general direction and supervision of customer service activities. Encourages the safe, efficient and economical use of the utilities services. (Customer Count Ratio)

UHC-EXEC MGMT-UTILITIES (5682)

Description: Provides guidance, direction and management to overall utility operations and support services. (Blended)

UHC-MARKETING (5688)

Description: Provides business and planning services, including marketing. Searches for competitive business opportunities and energy solutions (Blended)

UHC-EXTERNAL AFFAIRS (5690)

Description: Aligns business objectives with the integrated communications provided to our stakeholders. Including: media relations, coordination of community involvement programs, developing and managing a consistent communications program, and leading economic development for community growth (Customer Count Ratio)

UHC-Electric Meter Services (5691)

Description: Manages and provides electric measurement support to field operations located in electric service states. Also manages AMI system for all electric entities. (Customer-Regulated)

UHC-CUSTOMER SERV-LINCOLN (5701)

Description: Answers and resolves customer inquiries, requests for services, for both regulated and non-regulated customers. (Customer Count Ratio)

UHC-CUSTOMER ACCT SERV-OMAHA (5702)

Description: Assists customers with billing, payment and collection issues. (Customer Count Ratio)

UHC-CUSTOMER SERV SUPP (5703)

Description: Provides support to customer services areas through customer information system project management and process control for customer information system changes, revenue assurance analysis, quality analysis, training, and customer and community communication. (Customer Count Ratio)

UHC-CUSTOMER ACCT SERV-RC (5704)

Description: Assists customers with billing, payment and collection issues. (Customer Count Ratio)

UHC-CUSTOMER SERV-RC (5705)

Description: Answers and resolves customer inquiries and requests for services, for both regulated and non-regulated customers. (Customer Count Ratio)

UHC-LARGE VOLUME BILLING (5706)

Description: Manages and maintains regulated and non-regulated sales and billing of gas to large volume customers. (Customer Count Ratio)

UHC CS CTR SUPPORT (5707)

Description: Provides direct support to the operations of the two customer service centers in Lincoln and Rapid City. Provides analysis on employee staffing, monitoring service metrics, projects, and planning. (Customer Count Ratio)

UHC-BILL PRINT AND LOCKBOX (5711)

Description: Prepares prints, inserts and mails regulated and non-regulated letters and bills for BHC utility customers. Processes payments for regulated and non-regulated services mailed back to BHC by utility customers. (Customer Count Ratio)

UHC-BILL PROCESSING (5712)

Description: Outside services, supplies and postage expenses required for billing, correspondence, remittance, credit and collection services related to BHC utility customers. (Customer Count Ratio)

UHC-FIELD RESOURCE CTR-LINCOLN (5715)

Description: Plans work, and schedules and dispatches premise service activities to both regulated and non-regulated customers. (Customer Count Ratio)

UHC-FIELD RESOURCE CTR-RC (5717)

Description: Plans work, and schedules and dispatches premise service activities to both regulated and non-regulated customers. (Customer Count Ratio)

UHC-SERV GUARD MARKETING (6005)

Description: Provides and manages product development for consumer marketing with the primary focus on Service Guard (appliance options) a non-regulated business for utility/regulated customers. (Customers-Service Guard)

UHC Gas Engineering Management (6183)

Description: Provides management support to gas engineering and metering activities with emphasis on reliability, customer service, compliance and safety. (Blended)

UHC-TECHNICAL TRN-APPLIANCE (6331)

Description: Designs and implements safety programs and incentives, incident investigation, hazard identification and problem solving, and appliance repair technical skill training, program development and administration of technical-related training for our front-line utility employees supporting Service Guard. (Customers-Service Guard)

UHC-GAS REGULATORY SERV (6372)

Description: Supports and manages all gas regulatory filings, rate cases, and regulatory issues. (Blended)

UHC-ENERGY SERVICES (6373)

Description: Supports the energy efficiency programs across the utilities supported by BHUC (Customer Count Ratio)

CATCH-ALL

Description: Departments at Black Hills Corporation that are not specifically listed in the CAM or included in the master allocation design that charge BHUH will be allocated using the Blended Allocator Ratio.

Appendix 2- Allocation Ratios

Any asset ratios and employee and customer count ratios are calculated as of period-end dates, while revenue and expense ratios are calculated for twelve months ended as of period-end dates.

Asset Cost Ratio – Based on the total cost of assets as of December 31 for the prior year, the numerator of which is for an applicable operating company and the denominator of which is all applicable operating companies. Assets are limited to property, plant, and equipment, and include construction or work in process. Assets are also reported at their FERC value, meaning that assets for the utility subsidiaries will not include any elimination that are done to bring their FERC financial statements into compliance with GAAP. FERC requires that acquired fixed assets be recorded at their gross value with accumulated depreciation, while GAAP requires acquired fixed assets be recorded at their net value. An elimination journal entry is used to eliminate the gross-up for preparation of GAAP financial statements, but this elimination journal entry is not factored into the calculation of the Asset Cost Ratio.

No departments utilize this ratio, but it is a component in the Blended Ratio.

Gross Margin Ratio – Based on the total gross margin for the prior year ending December 31, the numerator of which is for an applicable operating company and the denominator of which is for all applicable operating companies. Gross margin is defined as revenue less cost of sales.

No departments utilize this ratio, but it is a component in the Blended Ratio.

Payroll Dollar Ratio –Based on the total payroll dollars for the prior year ending December 31, the numerator of which is for an applicable operating company and the denominator of which is for all applicable operating companies. Payroll dollars include all bonuses and compensation paid to employees, but do not include items that are only included on an employee's W-2 for gross-up and income tax purposes, such as life insurance premiums of $50,000.

No departments utilize this ratio, but it is a component in the Blended Ratio.

Blended Ratio – A composite ratio comprised of an average of the Asset Cost Ratio, Payroll Dollar Ratio and the Gross Margin Ratio. These factors are equally weighted. This factor is sometimes referred to as the general allocation factor.

Departments that utilize this ratio include BHUH benefits loading, retiree, BHUH accounting accruals, all blended assets, electric blended assets, gas blended assets, electric engineering services, electric regulatory services, utility margin accounting, utility financial management, utility accounting, utility operations management, utility market services, power supply and renewables, and gas regulatory services.

Any department at Black Hills Corp that appropriately charges a BHUH operating unit but is not part of the predefined allocation design will also utilize the Blended Allocator Ratio. For example if a BHSC IT department provides maintenance on the SCADA system supporting the regulated electric companies they would charge BHUH operating unit 201900 and these costs would be allocated using the Blended Ratio across the regulated electric companies.

Customer Count Ratio – Based on the number of customers at the end of the prior year ending December 31, the numerator of which is for an applicable operating company and the denominator of which is for all applicable operating companies.

There are currently several variations of the Customer Count ratio that are specific to the type of customers that are appropriate to the department for which charges are being allocated. For example a department that supports gas engineering would be allocated based on gas customers only whereas a general customer service department would be allocated based on total customers.

As of December 31, 2012 BHUH is utilizing the following customer counts to calculate customer count ratios additional variations may be added if additional product lines are added or in the event that additional segmentation of customers are deemed appropriate to most effectively allocate costs from a specific department

Regulated Electric Customers

Regulated Gas Customers

Non-Regulated Customers

Total Customers

Departments that utilize this ratio include gas supply services administration, computer aided dispatch, FAME assets, general assets, work management assets, regulated generation assets, customer blended assets, electric AMI blended assets, gas engineering services, GIS support, general meter shop, customer service management, Lincoln customer service center, Omaha customer account services, Rapid City customer service support, Rapid City customer account services, Rapid City customer service center, large volume billing, customer service center support, bill processing, Lincoln field resource center, Rapid City field resource center, service guard marketing, lockbox & bill-print, and appliance technical training.

Transmission Ratio – Based on a simple average of a multiple of cross-sectional drivers for the transmission function that includes customer counts, peak load, number of substations, number of feeders, number of distribution and transmission miles, and number of remote terminal units. The numerator of which is for an applicable operating company and the denominator of which is for all applicable operating companies.

The departments that utilize this ratio include transmission planning, NERC compliance, FERC tariff and compliance, transmission and distribution reliability, NERC transmission and tech support, and transmission service management.

Direct Testimony and Exhibits
Charles R. Gray

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 an Increase in Electric Rates
In South Dakota

Docket No. EL14-

March 31, 2014

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Exhibits

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Charles R. Gray. My business address is 105 South Victoria Avenue, Pueblo, Colorado.

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

A. I am employed by Black Hills Utility Holdings, Inc., a wholly-owned subsidiary of Black Hills Corporation ("BHC"). I am a Manager of Regulatory Affairs in the Regulatory Department.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of Black Hills Power, Inc., ("Black Hills Power", or the "Company").

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I attended Central Missouri State University in Warrensburg, Missouri, from which I received a Bachelor of Science-Education Degree. I also attended Longview Community College in Kansas City, Missouri, from which I received an Associates of Arts-Accounting degree. I have also attended many industry conferences and workshops throughout my 28 year career in the utility industry.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE.

A. In 1986, I began working for Missouri Public Service, a division of UtiliCorp United, Inc. (predecessor-in-interest to Aquila, Inc.) ("Aquila"), and held positions within the Accounting Department. My responsibilities included direct responsibility for the monthly billing of Missouri Public Service's Large Volume billing accounts, as well as preparation of financial and regulatory reports, monthly accounting journal entries and budgeting. In 1995, I joined Aquila's Regulatory Department as a Rates Analyst. I was promoted to Senior Rates Analyst in 2000. Following the sale of certain Aquila electric and gas properties to BHC, I accepted a position as Senior Regulatory Analyst located in Pueblo, Colorado. In 2013, I was promoted to Manager - Regulatory Affairs. Specifically, I am responsible for compiling and reviewing financial and customer billing information. I conduct analyses and prepare work papers and other supporting documents for various filings with regulatory agencies in several jurisdictions. I participate in the preparation of class cost of service studies, prepare rate design and develop tariffs.

II. PURPOSE OF TESTIMONY AND EXHIBITS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide a proof of test year revenue and billing determinants for Black Hills Power. I also provide revenue adjustments to the test year and the pro forma billing determinants priced out on the current and proposed rates. In addition, my testimony describes the jurisdictional cost of service study and the customer class cost of service study for the revenue requirement described in Jon Thurber's testimony. Finally, I discuss the principles used for rate design and sponsor the customer rate updates to the rate schedule tariffs.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am sponsoring the following exhibits:

- Exhibit CRG-1 – Test Year Billing Determinants
- Exhibit CRG-2 – Weather Normalization Adjustment
- Exhibit CRG-3 – Industrial Contract Service Accrual Adjustment
- Exhibit CRG-4 – Docket EL12-061 Rate Annualization Adjustment
- Exhibit CRG-5 – PIPR Rider Revenue Adjustment
- Exhibit CRG-6 – Pro Forma Billing Determinants on Current Rates
- Exhibit CRG-7 – PIPR & EIA Roll-In Adjustment
- Exhibit CRG-8 – Pro Forma Billing Determinants on Proposed Rates

Q. PLEASE DESCRIBE YOUR ROLE IN PREPARING THE EXHIBITS.

A. My role was to prepare the supporting exhibits listed above.

III. BILLING DETERMINANTS AND PROOF OF REVENUE

Q. PLEASE EXPLAIN THE PURPOSE OF EXHIBIT CRG-1.

A. The purpose of Exhibit CRG-1 is to price out the individual billing determinants using existing rates for the test year ended September 30, 2013 by rate schedule. This process is necessary for the proof of test year revenue using the current rates. The base rate revenue generated from Black Hills Power service is normally classified as a customer charge, demand/capacity charge or an energy charge. In addition to these normal billing charges, Black Hills Power's electric service revenues are also generated within the Cost Adjustment Summary by the Base

Costs, the Fuel and Purchased Power Adjustment ("FPPA"), Environmental Improvement Adjustment ("EIA"), Transmission Cost Adjustment ("TCA"), Energy Efficiency Solutions Adjustment ("EESA") along with rate schedule minimum monthly charges, equipment rental/lease fees, and the Phase in Plan Rate ("PIPR") rider.

Q. ARE THERE ANY BILLING CHARGES EXCLUDED FROM EXHIBIT CRG-1?

A. Yes. The revenue shown on Exhibit CRG-1 does not include sales taxes or franchise fees.

Q. PLEASE EXPLAIN HOW YOU DERIVED THE BILLING DETERMINANTS SHOWN ON EXHIBIT CRG-1?

A. I compiled the test year billing determinants by rate identification ("rate ID") from data recorded in the Company's Customer Information System ("CIS+"). This data was compiled from a total company level as well as individual customer billing records from CIS+ by month. From these sources, I cross checked the billing information to the income statement. The revenue for each rate ID was then grouped to the specific rate schedule.

Q. DOES THE CIS+ BILLING SYSTEM ASSIGN ONLY ONE RATE ID NUMBER FOR EACH TARIFF RATE SCHEDULE?

A. No. There can be multiple rate IDs within the CIS+ billing system for a specific rate schedule. The rate ID is used internally by the billing system to designate the proper rate component values to apply to a customer’s billed electricity usage during the process of calculating a customer’s bill.

As an example, Black Hills Power has a Residential Demand Service (Optional) tariff schedule but the tariff schedule has two rate ID’s associated with it. The Residential Demand Service tariff, Schedule RD, uses rate ID SD714 for the normal residential demand service accounts and SD716 for the Maximum Value Option Residential Demand Service accounts.

In total, the CIS+ billing system currently uses thirty (30) rate ID’s for metered electrical service and another seven (7) rate IDs for the unmetered street lighting and outdoor area lighting options available to customers.

Q. PLEASE DISCUSS THE FORMAT USED ON EXHIBIT CRG-1.

A. Exhibit CRG-1 lists each rate schedule by name and rate ID. The test year billing determinants are shown by revenue type along with the charge per unit and the total test year dollars billed by rate component. The various revenue components are summed and shown in total at the end of each rate section. This total is the total revenue for each rate ID. The schedule shows the unmetered usage billed and the revenue generated by each lighting schedule.

Q. DOES ANALYSIS OF TEST YEAR BILLING DETERMINANTS ALLOW ONE TO REACH ANY CONCLUSIONS CONCERNING BILLED REVENUE?

A. Yes. The analysis demonstrates that billed revenues used by Black Hills Power in its rate application are accurately reflected in the per books revenue presented in the filing.

IV. PRO FORMA REVENUE ADJUSTMENTS

Q. ARE YOU RESPONSIBLE FOR ANY REVENUE ADJUSTMENTS?

A. Yes. I have calculated four revenue adjustments that have been incorporated into the overall revenue requirement. The electric revenue adjustments are:

- Exhibit CRG-2 – Weather Normalization Adjustment
- Exhibit CRG-3 – Industrial Contract Service Accrual Adjustment
- Exhibit CRG-4 – Docket EL12-061 Rate Annualization Adjustment
- Exhibit CRG-5 – PIPR Rider Revenue Adjustment

Q. WHAT IS THE PURPOSE OF THE EXHIBIT CRG-2 WEATHER NORMALIZATION ADJUSTMENT?

A. Exhibit CRG-2 is a known and measurable adjustment to Black Hills Power's test year revenues. The adjustment is necessary to reflect the expected level of residential usage under normal weather conditions.

Q. HOW WAS THE RESIDENTIAL WEATHER NORMALIZATION ADJUSTMENT CALCULATED?

A. Black Hills Power began its analysis by comparing the monthly cooling degree day ("CDD") levels for the 30 year average CDD provided by the National Oceanic Atmospheric Administration ("NOAA") against the actual monthly CDDs during the test year for the city of Rapid City, South Dakota. The thirty-year average normal CDDs for Rapid City is 598 CDDs. During the summer of 2013 test year, Rapid City experienced 724 CDDs, which is approximately 21% warmer than normal conditions.

The next step in the analysis was to determine an appropriate level of base monthly sales volumes. In the analysis, Black Hills Power averaged the actual usage per customer for the months of April, May and October for the last nine years. Those three shoulder months have virtually no CDDs therefore it was appropriate to average the usage per customer for those three shoulder months over this historical period. The averaging of customer usage from those months resulted in an appropriate level of non-weather sensitive sales to compare against the weather sensitive sales volumes. Black Hills Power then backed out the non-weather sensitive sales from the actual test year residential sales to determine the cooling sensitive sales volumes.

The monthly volume variance of the weather normalized sales was then priced by applying the regular residential base energy charge of $0.08755/kWh. The residential weather adjustment resulted in a pro forma reduction of residential sales volumes of 7,363,852 kWh and a pro forma reduction of residential revenue of $644,705.

Q. WHAT IS THE PURPOSE OF THE EXHIBIT CRG-3 INDUSTRIAL CONTRACT SERVICE ACCRUAL ADJUSTMENT?

A. Exhibit CRG-3 is a known and measurable adjustment to the test year revenues for three customers. The test year usage and revenues for these customers are adjusted to achieve proper matching between test year revenues and expenses for the period of time in which the new rates become effective.

For example, the bill generated for September 2013 usage (Sept. 1-Sept. 30 meter read dates) is not produced until early October 2013. That billing information will be recorded as October 2013 usage and revenue in the billing system when 100% of the usage and revenue occurred in the previous month of September. Due to the mismatch between the billing system and the per-books financial information this adjustment properly aligns the billing system and the financial system.

Q. WHAT IS THE PURPOSE OF THE EXHIBIT CRG-4 DOCKET EL12-061 RATE ANNUALIZATION ADJUSTMENT?

A. Exhibit CRG-4 is a known and measurable adjustment to Black Hills Power South Dakota retail revenues to properly reflect the new rates that became effective during the test year.

Black Hills Power implemented approved rates in Docket No. EL 12-061 with an effective date of October 1, 2013. As these new rates were implemented following the end of the test year, this adjustment prices out the adjusted billing determinants on current rates and therefore properly reflects the proper level of revenue to be received from customers based on the recently approved rates. The revenue adjustment increases the per books revenues by $7,000,205.

Q. PLEASE DESCRIBE EXHIBIT CRG-5 PIPR RIDER REVENUE ADJUSTMENT.

A. Exhibit CRG-5 reflects the revenue adjustment as calculated in Schedule I-2 and allocates the additional revenue to each customer class. The additional revenue of $4,751,938 is allocated to each customer class consistent with the decision in EL12-062.

Q. WHAT WAS THE NEXT STEP IN YOUR ANALYSIS OF THE REVENUE?

A. The next step is to remove the Base Costs for each rate ID. Removing this revenue matches the energy expense adjustments as discussed in the testimony of Jon Thurber and allows these revenues and costs to be accounted for in the Energy Cost Adjustment (“ECA”). The next step in reconciling the customer revenue is to prove the above adjustments all flow into each customer class by rate ID. This is proven out in Exhibit CRG-6 that shows the adjusted billing determinants on current rates reconciling to Statement I, pg. 1, column (c), line 3, within $2,102.

Q. DID BLACK HILLS POWER ROLL ANY RATE RIDER CHARGES INTO THE BASE RATE CHARGES?

A. Yes. Black Hills Power rolled its Environmental Improvement Adjustment ("EIA") and the Phase In Plan Rate ("PIPR") into base rates. These revenues are shown by rate ID in Exhibit CRG-6.

The PIPR Rider revenue was rolled into the demand charge rate for the rate schedules that meter and bill a monthly capacity charge. Similarly, the PIPR Rider revenue was rolled into the energy charge if the rate schedule only bills on energy usage. The EIA was rolled into the energy charge for all rate schedules to follow the current collection method of a per kWh charge. Exhibit CRG-7 shows the new rates by rate ID following these adjustments and the final revenue amount still reconciles to Statement I, pg. 1, column (c), line 3 within $2,193.

Q. WHY ROLL THE RIDER REVENUES INTO THE APPLICABLE BASE CHARGES?

A. These riders were for investments that are or have been moved into rate base. For example, the PIPR Rider is to recover the construction financing costs during construction and once the plant is placed into service, the cost recovery for CPGS will be handled through base rates.

Q. WHAT IS THE PURPOSE OF EXHIBIT CRG-8?

A. The purpose of Exhibit CRG-8 is to provide a proof of revenue based on proposed base rates to recover the additional revenue needed as supported by Section 4, Statement N-1.

V. OVERVIEW OF RATE DESIGN

Q. WHAT STEPS DID THE COMPANY FOLLOW TO DESIGN RATES?

A. The first step is to determine the overall cost of service. The overall cost of service is also commonly referred to as the revenue requirement. The next step is to determine the jurisdictional cost of service. Then Black Hills Power performs a class cost of service study in order to allocate the costs across the rate classes based on cost causation and service type. Finally, based on the results of the jurisdictional and class cost of service studies, revenue targets and rate elements are calculated and then modified where necessary to meet the rate design objectives.

Q. ARE BLACK HILLS POWER'S CURRENT RATE DESIGN AND RATE STRUCTURES APPROPRIATE?

A. Yes. Black Hills Power has worked over time to design rates that are easy for customers to understand, have been accepted by customers, and provide for ease of administration. In addition, Black Hills Power rates are structured to provide appropriate price signals to customers to encourage optimum use of supply sources by promoting desirable load characteristics. Black Hills Power is proposing to modify several rate structures to further provide more appropriate price signals and simplify tariffs for ease of administration. Those modifications are discussed later in my testimony covering the proposed tariffs.

Q. WHAT SCHEDULES SUPPORT BLACK HILLS POWER'S RATE DESIGN STEPS?

A. The pro forma cost of service study by jurisdiction is provided in Schedule N-1 and Statement N for the per books. The cost of service study is supported by Schedule O-1 for the pro forma and Statement O for the per books. Based on the results of the jurisdictional and class cost of service studies, the rate design for each tariff schedule is provided in Exhibit CRG-8.

VI. JURISDICTIONAL COST OF SERVICE STUDY

Q. WHAT IS THE PURPOSE OF THE JURISDICTIONAL COST OF SERVICE STUDY?

A. The purpose of the jurisdictional cost of service study is to allocate costs among the various jurisdictions in which Black Hills Power operates, including South Dakota, Wyoming, Montana, and Federal Energy Regulatory Commission ("FERC"). The jurisdictional cost of service establishes the revenues needed from South Dakota retail customers to recover the Company's reasonable return on rate base, as well as operational and maintenance, depreciation, and tax expenses.

Q. PLEASE DESCRIBE THE STEPS INVOLVED IN CONDUCTING A JURISDICTIONAL COST OF SERVICE STUDY.

A. The steps involved in conducting a jurisdictional cost of service study are similar to the class cost of service study. An allocation percentage is used to allocate rate base and costs based on the main driver of the rate base or expense. For example, production facilities are allocated based on demand since generation is built to handle specific demands of Black Hills Power's customers. This methodology conforms to general cost causation rate making principles. Consistent allocation methodologies are used between the jurisdictional and class cost of service studies whenever possible and appropriate. The FERC jurisdictional investments and costs are primarily directly assigned based on the approved annual formula rate methodology in accordance with Black Hills Power's FERC Joint Open Access Transmission Tariff for the 230 kV Common Use System.

Q. ARE THE JURISDICTIONAL ALLOCATION METHODOLOGIES CONSISTENT WITH BLACK HILLS POWER'S PREVIOUS RATE CASE IN SOUTH DAKOTA?

A. Yes, the current jurisdictional cost of service study is consistent with the previous rate case in South Dakota.

VII. CLASS COST OF SERVICE STUDY

A. Overview of Class Cost of Service Study

Q. WHAT IS THE PURPOSE OF THE CLASS COST OF SERVICE STUDY?

A. A Class Cost of Service Study ("CCOSS") is performed to determine the revenue requirement for each class of customers. This is accomplished by assigning, or allocating, the detailed components of the revenue requirement to individual customer classes using allocation factors that reflect the nature of the particular cost component being allocated. The total cost of service is distributed among the various customer classes in such a manner that the sum of the customer class revenue requirements equals the South Dakota jurisdictional revenue requirement. This type of cost of service study is generally referred to as a "fully distributed" cost of service study since all company costs that make up the revenue requirement are allocated to customer classes.

Q. WHY ARE COSTS ALLOCATED TO CUSTOMER CLASSES?

A. Costs are allocated to customer classes in order to provide customer class revenue guidelines for rate design purposes. In addition, the CCOSS results provide information regarding the level of classified component costs per unit (e.g., demand cost per kW or kVA, energy costs per kWh, and customer costs per customer per month) which is useful in the design of rates.

Q. PLEASE DESCRIBE THE STEPS INVOLVED IN CONDUCTING A CCOSS.

A. There are three steps involved in conducting a CCOSS - functionalization, classification, and allocation. Functionalization identifies the operational source where the costs are incurred, either directly or indirectly, with respect to the physical process of providing service. For example, the costs of generating units and purchased power (production function) are identified separately from costs associated with transmission lines (transmission function) which are, in turn, segregated from the costs of the distribution system (distribution function).

The next step in conducting a CCOSS, classification, refers to the separation of costs according to the usage characteristic that drives the cost – e.g., demand, energy and customer-related costs. Demand costs are costs that arise as a result of the rate of power consumption over a short period of time (usually 15 minutes to one hour). Energy costs are those costs that result from the volume of energy supplied over time. Customer costs are costs that vary as a function of the number of system customers.

The final step in conducting a CCOSS is allocation. Allocation is the process of using customer class metrics, along with the knowledge that certain costs are incurred exclusively for the benefit of specific identifiable customers, to allocate or assign the specific cost components that have been functionalized and classified to individual customer classes. Customer class information such as annual energy use, class demand at time of system peak, weighted meter costs, and customer counts are employed to calculate class allocation factors.

Q. PLEASE DESCRIBE THE PROCESS OF COST FUNCTIONALIZATION EMPLOYED IN THE CCOSS.

A. Once all the individual cost components representing the total revenue requirement have been collected for the CCOSS the components are separated according to the function or physical service they provide. These functions are:

- Production – costs associated with the production of energy and capacity, including purchased power;
- Transmission – costs associated with the high voltage system that transports the power to load centers;
- Distribution – costs associated with distributing the energy from the transmission system to the end users;
- Customer Service – costs associated with providing service to the customer –e.g., service drops, metering, billing, the customer-related portion of transformers and conductors, and similar costs; and
- Administrative and General – common costs, such as management, buildings, software, support services, and similar indirect costs that are incurred to support the other functions of electric service.

Q. PLEASE DESCRIBE THE PROCESS OF COST CLASSIFICATION EMPLOYED IN THE CCOSS.

A. Cost classification is the process of further categorizing the functionalized costs according to the cost driving characteristic of the utility service being provided. The three principal cost classifications are demand-related costs, energy-related costs and customer-related costs.

Demand-related costs are those fixed costs that are related to the kilowatt ("kW") demand that the customers place on the system at any point in time. These costs vary with the maximum demand imposed on the various components (facilities) of the power system by customers. Energy-related costs are those costs that are related to the kilowatt-hours ("kWh") of energy that the customer utilizes over time. These costs, such as fuel, vary with the overall quantity of energy. Customer-related costs are those costs incurred as a result of the number of customers on the system. These costs, such as meters and billing, are incurred to serve individual customers.

As described later in my testimony, operating and accounting data are used to develop allocation factors that link cost causation factors (demand, energy and customers) to the costs that comprise Black Hills Power's revenue requirement. These allocation factors are calculated as percentages and applied to specific costs and rate base items to derive the cost of service for each customer class.

Q. ONCE THE COSTS ARE FUNCTIONALIZED AND CLASSIFIED, WHAT IS THE NEXT STEP IN THE PROCESS OF CALCULATING THE CLASS COST OF SERVICE?

A. After the functionalization and classification steps, class responsibility for each cost is determined using the allocation factors referred to above. Each identifiable element of the revenue requirement is allocated to each customer class on the basis of imposed demand (using either average and excess ("A&E") or a calculated maximum demand), energy at the generation source (after accounting for line and transformer losses), or number of customers served (weighted by the appropriate weighting factor to recognize differences in types of customers and their impacts upon the system). These allocations are then summarized within the cost of service model.

Q. PLEASE DESCRIBE THE LAYOUT AND OPERATION OF THE CLASS COST OF SERVICE MODELS IN THIS FILING.

A. The CCOSS provided as Statement O - Per Books Class Cost of Service Study and Schedule O-1 - Pro Forma Class Cost of Service Study are organized as a cost matrix. Each row of the model identifies a particular detailed component of the total cost to provide service. The columns on Schedule O-1 consist of the allocation of costs to each customer class. The development of the costs of serving each customer class begins with the allocation of revenues, and continues with the allocation of operating expenses, taxes, rate base and the computation of labor and other allocators.

Q. PLEASE DESCRIBE THE OUTPUT OF THE COST OF SERVICE MODELS IN THIS FILING.

A. Page 1 of the CCOSS summarizes the allocated components of the revenue requirement and presents the rate of return by customer class at present rates. As indicated by this summary, the present rates charged to some classes produce a rate of return for that class that is below the system average rate of return while the present rates charged to other classes produce a higher than system average rate of return. The rate of return at present rates is also shown as a ratio of each classes return to the system return, which is referred to in the CCOSS as the "Index Rate of Return". An Index Rate of Return of 1.00 means that the class' return is the same as the system return. An Index Rate of Return of less than 1.00 means that the class' return is less than the system return. Conversely, an Index Rate of Return of greater than 1.00 means that the class' return is greater than the system return.

Page 2 of the CCOSS summarizes the allocated components of the revenue requirement and presents the rates of return by customer class at Black Hills Power's requested rate of return of 8.48%. The results summarized on this page set forth the revenue requirements for each class.

Page 3 of the CCOSS presents the rate of return by customer class at Black Hills Power proposed rates.

Pages 4 through 10 of the CCOSS set forth in Schedule O-1 provide the allocation of rate base to customer classes. The allocations of gross plant in service are provided on pages 4 through 6. The allocations of accumulated depreciation are provided on page 7. Additions and deductions to rate base are provided on page 8 along with the summary of rate base by customer class. Pages 9 and 10 include line item detail for the Addition to Rate Base item Cash Working Capital.

Allocated Operating Revenues are provided on page 11 of Schedule O-1. The allocation of operation and maintenance expense by account is set forth on pages 12 through 15. Page 16 provides the detailed allocation of depreciation expense by account to each customer class. Taxes Other than Income Taxes are allocated to customer classes on page 17. The components of Income Taxes and the calculation of Income Taxes by customer class are provided on pages 18 and 19 of Schedule O-1. Note that Income Taxes are not directly allocated to each customer class, but rather the components used to calculate income taxes are allocated to each customer class instead. These allocated income tax components are then used to calculate the Income Tax liability for each class based upon the allocated tax components.

The remaining pages of the CCOSS provide the information employed to develop the allocation factors employed in the cost of service study. Page 20 details the development of the salaries and wages allocation factors used in the study. Finally, pages 21 through 35 provide the detailed information used to develop the other allocation factors employed in the CCOSS. These allocation factors consist of both externally and internally developed allocation factors. Externally developed allocation ratios reflect customer class metrics such as A&E and calculated maximum demand at various voltage levels, energy sales, and as measured at both the generation level and at the meter (*i.e.*, with and without line and transformer losses), and number of customers by voltage level. Externally developed allocation factors are developed outside of the cost of service study and then input into the study. In contrast, internally developed allocation factors are calculated within the cost of service study using previously allocated cost components to derive factors that reflect the combined impacts of multiple cost drivers.

Q. IN YOUR OPINION, ARE THE COST OF SERVICE STUDIES TRANSPARENT AND VERIFIABLE?

A. Yes, I believe the cost of service studies are transparent and verifiable. The jurisdictional cost of service and the CCOSS submitted in Statement N, Schedule N-1, Statement O, and Schedule O-1, provide complete detail as to each allocation made on an account-by-account basis. In addition, cross-references to supporting schedules are provided on all summary pages. Every calculation made in the model can be readily verified by Commission Staff and other parties to the case. The cost of service model used by Black Hills Power in this filing is subject to protective restrictions since its internal computations are confidential trade secrets of Management Applications Consulting, Inc. The Company will provide a working model of its licensed cost of service studies to Staff and any intervenors upon execution of the necessary confidentiality agreements.

B. Cost Allocations

Q. PLEASE DESCRIBE THE ALLOCATION OF POWER SUPPLY RESOURCES IN THIS CURRENT RATE CASE.

A. In this filing, Black Hills Power continues to use the A&E allocation method for power supply capacity costs. The A&E allocation is consistent with the approach used in previous rate cases. This methodology reasonably and justly represents the factors that affect Black Hills Power's demand-related supply costs.

Q. PLEASE DESCRIBE THE A&E CAPACITY ALLOCATION METHODOLOGY.

A. The A&E allocation methodology has two distinct components to its calculations of responsibility for the system peak demand of 302 MW. The system peak demand for the test period occurred on August 27, 2013. First, each customer class is allocated its average kW demand during the test year. Average kW demand is determined by taking the total kilowatt hour sales for the class, plus associated energy losses, divided by the number of hours within the test period. In this case, the number of hours used was 8,760, which is 365 x 24 hours. The second component of the A&E demand allocation, allocates the remaining system peak demand (excess demand) not allocated by the sum of the individual class average demands. The excess demand is allocated based upon the relationship of the individual class non-coincident peak demand determined for the test period. The result of this approach is that customer classes with lower load factors are responsible for a greater percentage of the excess demand, whereas customers with higher load factors are responsible for a greater percentage of the average demand. This approach has the tendency to recognize that systems are made up of both base load resources and peaking resources, and that the load factors associated with each class of customer allows system planners to acquire various mixes of resources.

Q. WHY WAS THE A&E CAPACITY ALLOCATION METHOD SELECTED FOR THIS RATE CASE?

A. The A&E capacity allocation method has been used by the Company and approved by the Commission in all of its previous rate case proceedings in South Dakota. Therefore, the results of this method are consistent with past cost allocation and the rate design provided for in the Company's rate schedules. The A&E allocator is also recognized by the National Association of Regulatory Utility Commissioners ("NARUC") as an acceptable capacity allocation methodology in the <u>Electric Utility Cost Allocation Manual</u> ("Manual"). Finally, Black Hills Power's system, with similar summer and winter peaks, should use a methodology that recognizes both the need to plan for base load resources and the need to acquire peaking resources. The A&E methodology fits this need.

Q. PLEASE DESCRIBE THE PROPOSED ALLOCATION OF TRANSMISSION COSTS.

A. Over 96% of Black Hills Power's transmission system and related costs are allocated to the FERC jurisdiction for the 230 kV Common Use System that is owned and operated by Black Hills Power, Basin Electric Power Cooperative, and Powder River Energy Corporation. The characteristics of the remaining transmission system, to be first allocated to the state jurisdictions and then South Dakota customers, are more closely related to the distribution system. For example, some of the substation assets that provide step down transformation from transmission to distribution service remain to be allocated. Due to the nature of these assets and related costs, the Company proposes to use the Calculated Maximum Demand, or Non Coincident Peak ("NCP"), allocation methodology. This is consistent with the methodology used to allocate certain distribution assets and related costs as provided further in my testimony below.

Q. WHAT IS THE RECOMMENDATION IN THE CURRENT CASE REGARDING THE CLASSIFICATION AND ALLOCATION OF DISTRIBUTION ACCOUNTS 364 THROUGH 368?

A. The Company recommends classifying these distribution accounts as demand and using the NCP allocation methodology. Several approaches were considered when determining the demand and customer classification of these accounts, such as the Minimum-Size Method and the Minimum-Intercept Approach that are provided in NARUC's Manual. However, the evaluation of these methods on page 95 of the Manual identifies issues in each of the methods. Due to the potential misclassification or misallocation to customer classes from these shortcomings associated with employing these classification methods, the Company elected to classify these accounts as demand. Since local area loads are the major factors in sizing distribution equipment, the customer class non-coincident demand is used to allocate the distribution accounts. This classification and allocation of these distribution accounts is consistent with Black Hills Power's previous rate cases.

Q. DO THE ALLOCATIONS OF DISTRIBUTION PLANT IN THE CCOSS RECOGNIZE DIFFERENCES BETWEEN PRIMARY AND SECONDARY FACILITIES?

A. Yes, as indicated on page 5 of Schedule O-1, Accounts 364 through 367 recognize that some distribution customers are served from the primary voltage system and other distribution customers are served at secondary voltage. This differentiation by voltage level allows secondary costs to be allocated only to secondary customers.

Q. HOW ARE THE REMAINING DISTRIBUTION PLANT ACCOUNTS ALLOCATED TO CUSTOMER CLASSES?

A. Account 369 - Services includes customer-related costs that are allocated to classes on the basis of weighted class NCP demands. Account 370 - Meters is allocated to classes on the basis of the number of customers weighted by the relative cost of a meter for that class. The remaining plant accounts, Account 371 - Installations on customer premises and Account 373 - Street lighting and signal systems are exclusively used for lighting services of Black Hills Power. Therefore, these accounts are directly assigned to the Lighting class as a whole.

Q. BRIEFLY DESCRIBE THE ALLOCATION OF GENERAL PLANT.

A. General Plant does not readily fall into a demand, energy, or customer classification because general plant reflects indirect common costs necessary to operate a utility system. Generally speaking, general plant consists of plant and equipment necessary to support overall organization personnel. In performing a CCOSS, Operation and Maintenance ("O&M") expenses for production, transmission, distribution, customer accounting and customer information have already been functionalized, classified and allocated to classes. As a result, the level of wages and salaries recorded in the O&M expense accounts is known and allocation factors are developed using this information. In summary, general plant is allocated on the basis of the prior assignment of distribution wages and salaries by operation and maintenance expense accounts. This method is recognized by NARUC in its Manual (page 105).

Q. HOW ARE THE REMAINING RATE BASE ITEMS ALLOCATED TO CLASSES?

A. Accumulated depreciation is allocated to classes based upon the prior allocation of related plant accounts. Additions and deductions from rate base are allocated using the most appropriate allocation factors for the items being assigned. For example, cash working capital is allocated to classes on the basis of an analysis of specific components on pages 9 and 10 of the CCOSS that encompass the leads and lags of expenses; fuel inventory is allocated based upon the allocation of fuel expense; materials and supplies inventory is allocated to customer classes on the basis of total plant in service; prepayments are allocated on the basis of previously allocated O&M expenses excluding fuel and purchased power; customer advances for construction are allocated based upon a direct assignment; and regulatory assets, regulatory liabilities, and deferred taxes are allocated based on salary and wages, total plant, or customer based on the nature of the specific accounts.

Q. HOW ARE OPERATING REVENUES ALLOCATED?

A. Sales of electricity are recorded by customer class and are, therefore, directly assigned. Account 450 - Forfeited Discounts are allocated on the basis of expense Account 904 - Uncollectible Accounts. Miscellaneous service revenues are allocated on the basis of distribution plant. Rent from electric property is allocated on the basis of previously allocated transmission and distribution plant in service. The allocations of operating revenues are set forth on page 11 of the CCOSS.

Q. PLEASE DESCRIBE THE ALLOCATION OF POWER PRODUCTION EXPENSE AND OTHER POWER SUPPLY EXPENSES.

A. Accounts 501 - Fuel and 547 - Other Power Generation Fuel are eliminated from the revenue requirement as provided in the testimony of Jon Thurber. All other power production expenses other than supervision and engineering accounts are allocated on the basis of the production allocation factor which, as explained above, is calculated on the basis of the A&E allocation methodology. Supervision and engineering accounts are allocated based upon the allocation of wages and salaries recorded in the related series of accounts. For example, Account 500 - Supervision and Engineering (steam production operation) is allocated on the basis of the allocation of wages and salaries allocated in Accounts 501 through 506; Account 510 - Supervision and Engineering (steam production maintenance) is allocated on the basis of the allocation of wages and salaries allocated in Accounts 511 through 514; Account 546 - Supervision and Engineering (other power generation operation) is allocated on the basis of the allocation of wages and salaries allocated in Accounts 547 through 549; and Account 551 - Supervision and Engineering (other power generation maintenance) is allocated on the basis of the allocation of wages and salaries allocated in accounts 552 through 556. Finally, the energy component of purchased power is removed from the revenue requirement and discussed further in Jon Thurber's testimony, while the demand portion of the purchased power bill and other power supply expenses are allocated using the demand-related production allocation factor discussed above.

Q. PLEASE DESCRIBE THE ALLOCATION OF TRANSMISSION EXPENSES.

A. For this CCOSS, the expenses booked in most O&M expense accounts are related to a specific property account that has already been allocated to the FERC jurisdiction. In addition, the Transmission of Electricity by Others (Account 565) is completely removed for Base Costs as further explained in Jon Thurber's testimony. For these reasons, all transmission costs except for the Supervision and Engineering accounts (Accounts 560 and 568) are allocated on the basis of total allocated transmission plant. Transmission Supervision and Engineering expenses are allocated on the basis of the sum of the allocation of wages and salaries in the related series of accounts in the same manner as production expenses.

Q. PLEASE DESCRIBE THE ALLOCATION OF DISTRIBUTION EXPENSES.

A. Similar to the transmission plant related O&M expenses, the distribution O&M expenses are allocated based on the distribution plant allocator. For example, overhead line operation expense and maintenance expense are allocated on the basis of the allocation of overhead lines; street light related expenses are allocated on the basis of the allocation of street lights; transformer maintenance expense is allocated on the basis of the allocation of transformers; and so forth. Similarly, distribution supervision and engineering expenses are allocated on the basis of the summed allocation of the wage and salary components among the allocated series of expense accounts. Accounts 581 - Load Dispatching, 588 – Miscellaneous Operation Expenses, 589 - Rents, and 598 - Miscellaneous Maintenance Expense are allocated on the basis of total distribution plant.

Q. PLEASE DESCRIBE THE ALLOCATION OF CUSTOMER ACCOUNTS EXPENSES AND CUSTOMER SERVICE EXPENSES.

A. These accounts are customer-related accounts that are allocated on the basis of the number of bills or number of customers. Account 904 - Uncollectible Accounts are allocated on the basis of customer account write-offs during the test period. Supervision expenses are allocated based upon the allocated wages and salaries of the related series of accounts.

Q. PLEASE DESCRIBE THE ALLOCATION OF ADMINISTRATIVE AND GENERAL ("A&G") EXPENSES.

A. A large portion of A&G activities support the functions and activities carried out by Black Hills Power employees. Therefore, many A&G expense accounts are allocated on the basis of allocated wages and salaries for all other accounts. Property insurance is allocated on the basis of total plant in service. Regulatory commission expense is allocated on claimed revenues. Rents and Maintenance of General Plant are allocated on General Plant.

Q. PLEASE DESCRIBE THE ALLOCATION OF DEPRECIATION EXPENSE.

A. In a manner similar to accumulated depreciation, depreciation expense by account is allocated on the basis of the associated plant.

Q. PLEASE DESCRIBE THE ALLOCATION OF TAXES OTHER THAN INCOME TAXES.

A. Taxes other than income taxes are allocated based upon the most appropriate allocation. For example, FICA and federal and state unemployment taxes are allocated on the basis of total allocated wages and salaries. South Dakota Public Utilities Commission taxes are allocated on the basis of claimed revenues, and property taxes are allocated on the basis of the total plant in service.

Q. PLEASE DESCRIBE THE ALLOCATION OF INCOME TAXES.

A. As previously stated, income taxes are not directly allocated to customer classes. Instead, the components used to calculate income taxes are allocated to each customer class. These allocated income tax components are then used to calculate the income tax liability for each customer class based upon the allocated tax components. The detailed computation of federal income taxes are set forth on pages 18 and 19 of the CCOSS provided in Schedule O-1.

C. Overview of Class Load Data

Q. WHAT DATA WAS USED TO DEVELOP THE CUSTOMER CLASS DEMAND ALLOCATORS AND DESCRIBE YOUR ROLE IN THE PREPARATION OF THE ALLOCATORS?

A. Black Hills Power retained a load research consultant to develop customer class load shapes which were then used in the allocation process of demand related costs in the CCOSS. The consultant was provided the same monthly billing determinants used in Exhibit CRG-1. He was also provided with test year hourly interval data by rate for virtually all customers from their AMI meter. Several of the largest customers are currently billing on non-AMI meters, so customer hourly interval data from the recording demand meters was utilized. For non-metered services, street and private area lighting, the consultant created monthly load shapes based on number of nighttime hours of expected lighting usage.

Q. WHAT IS THE PURPOSE OF CREATING CUSTOMER CLASS LOAD SHAPES?

A. Customer class load shapes are used in creating demand allocators for use in the CCOSS to assign costs to the various customer classes. This load shape information is not available from data collected in the routine billing of customers, so historically, the load shape was estimated based on samples drawn from classes of customers. With the availability of AMI information for almost all customers, sampling is no longer necessary, as hourly information is available by rate.

Q. HOW WERE THE CUSTOMER CLASS LOAD SHAPES CREATED?

A. Load shapes were created using the data provided. For the customer classes with AMI data, we multiplied each hour, typically by rate, by the ratio of the billed kWh to the sum of the annual hourly values available from AMI. This is the form of a Combined Ratio Estimator – one of the industry standard methods of estimation – and has the effect of raising or lowering the entire shape so it exactly reflects the billed kWh used for creating billing determinants.

Q. HOW WAS THE DEMAND INFORMATION USED?

A. The demand information developed from Black Hills Power's data was used to create allocators by dividing each customer class demand estimate by the sum of the customer class demand estimates such that the sum of the results equals 1. These allocations are illustrated in Schedule O-1.

Q. CAN THE CUSTOMER CLASS LOAD SHAPES, DEMAND ESTIMATES AND DEMAND ALLOCATORS THAT YOU DEVELOPED BE USED RELIABLY IN THE CCOSS?

A. Yes. The customer class load shapes, demand estimates and demand allocators have been developed, are reasonable and can be reliably used in Schedule O-1, to assign costs to the various customer classes. The demand estimates were modified by loss factors to account for the line losses between generation stations and the retail meters where the load shape data is collected. The demand allocators were all developed using industry standard methods.

D. Results of Study

Q. PLEASE SUMMARIZE THE RESULTS OF THE CCOSS.

A. As the results of the CCOSS indicate, moving the current customer class rates of return produced at present rates to the system return of 8.48% would require large increases to the base rates for three of the five customer classes and a smaller increase to one customer class and reduction to base rates for two customer classes. In order for each customer class to produce the system rate of return of 8.48%, this requires increases to Residential rates by 19.26%, General Service Large/Industrial Contract by 15.44%, and 3.45% to the Water Pumping/Irrigation class. This also requires a reduction of General Service rates by 6.37%, and Lighting Service rates by 15.74%.

Q. WHAT CONCLUSIONS HAVE YOU REACHED REGARDING THE RESULTS OF THE COST OF SERVICE STUDIES?

A. The methods and procedures applied in the jurisdictional and CCOSS are consistent with traditional rate making principles employed by the electric utility industry and Black Hills Power. In addition, the results of these cost of service studies justly and reasonably reflect the cost to serve the various customer classes for Black Hills Power and the results provide a sound basis for designing just and reasonable rates for each of its customer classes. Black Hills Power also recognizes the significant increases the CCOSS developed for both of the smallest customers, the residential customer class, as well as our largest customers, the

Industrial Contract Service customer class. As previously mentioned, our rate design philosophy must consider the history of rates, including trends in the level of charges and stability of the rates as well as the degree of price sensitivity in each customer class.

The direct testimony of Kyle White provides a method to move to cost-based rates. In particular, he discusses the concept of gradualism, so that rates are not increased in one step, since certain classes would experience rate shock from the resulting large increase in a single customer class and reallocation of costs reflected in a single move to full cost of service rates.

In class cost of service modeling, a complete elimination of all inter-class subsidies can often have significant adverse implications on a given customer class. By employing the concept of gradualism, significant rate shifts, for the Residential and General Service Large/Industrial Contract Service customer classes in this case, are minimized by moving all customer classes to the full cost of service rates over several smaller steps as opposed to one leap to full cost of service.

Q. WILL ALL CUSTOMERS IN A CUSTOMER CLASS RECEIVE THE SAME PERCENTAGE CHANGE FROM CURRENT RATES?

A. No. The proposed percentage change for a customer class will more closely follow the revenue requirement indicated by the CCOSS for each particular Rate ID while following the gradual move to full cost of service. However, within a rate class, the study may have identified certain subclasses that may need a different percentage. So the change from current rates might go up more for one subclass and less of an increase for another, while the customer class still receives the total required customer class increase.

Q. HOW WERE THE PERCENTAGE INCREASES APPLIED TO THE PROPOSED CUSTOMER RATES?

A. Generally, increases were applied across all rates for each rate schedule. Some of the customer charges are rounded to the closest 5 or 10 cents after being raised the class percentage increase required. In addition, for some customer classes, the increase is assigned more to the demand charge, if the CCOSS supported such charge, rather than the energy charge in order to incent customers to achieve higher load factors. The proposed rates will allow Black Hills Power the opportunity to collect the revenue requirement level derived by Schedule N-1.

VIII. <u>PROPOSED RATES</u>

Q. DISCUSS THE PURPOSE OF EXHIBIT CRG-8.

A. The purpose of Exhibit CRG-8 - Pro Forma Billing Determinants on Proposed Rates is to price out the pro forma billing determinants using rates that align with costs caused by each customer class and the appropriate revenues collected by customer class while implementing the rate shock mitigation plan offered in the testimony of Kyle White.

The Pro Forma CCOSS is provided as Schedule O-1. The pro forma billing determinants provided in Exhibit CRG-8 are also carried over to Section 3 Revenue Comparison.

Q. DISCUSS THE PROCESS YOU USED IN DEVELOPING THE BASE RATES SHOWN ON EXHIBIT CRG-8.

A. The CCOSS is the guide in developing the proposed rates. Black Hills Power used the same billing determinants as provided in Exhibit CRG-7. That is, Black Hills Power used the same number of customer bills, same monthly billed kW demand and the same kWh consumption for each individual rate schedule. The total electric revenue deficiency of $14,634,238 causes an overall deficiency of 9.27% of current base revenues. An across the board rate increase of 9.27% would provide Black Hills Power the opportunity to reach its total South Dakota revenue requirement of $138,803,591 as shown on Schedule N-1, Page 2, Column (c), Line 73.

Q. PLEASE EXPLAIN HOW THE ALLOCATION PROPOSAL WAS DEVELOPED FOR EACH CLASS.

A. The Company's customer class allocation proposal sets upper and lower limits to each customer class's contribution to the overall South Dakota revenue deficiency. The rate shock mitigation plan set the upper limit on any type of class of customers at 120% of the overall base revenue deficiency percentage. The lower limit is set at 75% of the overall base revenue percentage increase. All customer classes will see some level of increase, the CCOSS results will define the level each customer class will contribute to the overall revenue deficiency. This proposal provides a significant movement of rates toward full class cost of service levels while maintaining accurate and equitable pricing, tempered by moderation. The moderation in this proposal also recognizes the overall level of the proposed increase.

Using the proposed customer class revenues and applying rate design factors mentioned herein, Black Hills Power developed appropriate base rate charges. These charges are necessary to allow the Company the opportunity to recover, from each class, the appropriate class revenue requirement and the total annual revenue requirement proposed.

Q. WHAT IS YOUR CONCLUSION CONCERNING THE ADDITIONAL REVENUE REQUIREMENT REQUEST OF $ 14,634,238?

A. Black Hills Power's analysis demonstrates that Exhibit CRG-8 pro forma billing determinants priced out on the increased base rate charges provided in proposed rate schedule tariffs will allow the Company the opportunity to recover the revenue requirement proposed by Black Hills Power in this rate application.

IX. PROPOSED CHANGES TO TARIFFS

Q. ARE ANY RATE STRUCTURES ON EXISTING TARIFFS BEING MODIFIED OR ELIMINATED?

A. Yes. Black Hills Power has reviewed its tariffs and has proposed several refinements to the General Service, General Service-Large and Forest Products Service tariff options. The current rate structures for these tariffs have multiple billing steps based on differing levels in the demand charge and also in the energy charge. Our proposal is to reduce the number of steps from three to two in order to allow for a more simplified bill calculation as well as the elimination of some inter-class subsidies from the larger users to the smaller users on the same tariff.

Additionally, the enhanced capabilities of the AMI meters provide Black Hills Power with complete and accurate demand readings from all of its General Service customers not possible with the prior General Service meters used for billing. The history behind the first demand billing bucket, 0 – 5 kW, originated out of the smaller General Service customers having a non-demand watt hour meter. Their previous electric meter did not register demand, only kilowatt hours consumed, the same as with regular residential meters. As evidenced on Exhibit CRG-6, Pro Forma billing determinants on current rates, almost 30% of the total kW measured for General Service (Rate ID SD720) currently goes uncharged. To recover the appropriate demand dollars, a larger charge per billed kW is necessary to achieve the desired revenues. With the roll out of the new AMI meters, all customer meters now register both energy (kWh) and demand (kW) for the billing period. As accurate demand readings are now recorded in the billing system, the actual metered demand for all general service customers can be billed appropriately. The proposed rates have consolidated the 0- 5 kW demand bucket with the 5- 50 kW bucket. In rate design process, by billing for all demand from all General Service customers, the proposed rates offer a lower charge per kW for the customers falling in the 5 -50 kW demand level than might ordinarily occur if the current pricing structure was retained. The over 50 kW bucket is retained for the largest users at this time. Further, the Company is proposing to consolidate the current four step energy charges into a two step energy charge, 0 - 3000 kWh in bucket one and all remaining kWh in bucket two.

The General Service-Large tariff will have three step energy charges consolidated to two energy buckets, with the lower pricing applied to energy used with a load factor over 55% at 125 kVA capacity. This provides the pricing incentive for customers to manage their peak demand and improve their load factor. The two step demand charge will remain in place.

The modification to the Forest Products Service tariff follows the General Service-Large load factor concept. The three step demand charge will be consolidated into a two part demand charge, the first bucket of 0 -5,000 kVA and second bucket of all excess kVA. The three step energy charge calculation will become a two step charge, the first 800,000 kWh in the first bucket and excess kWh in the second bucket. These modifications will provide the pricing break at the 55% load factor level similar to the General Service-Large tariff.

Black Hills Power believes these modifications will provide appropriate price signals to customers to encourage optimum use of supply sources by promoting desirable load characteristics, provide tariffs that are easy for customers to understand, provide for ease of administration while avoiding undue discrimination between customer classes and individual customers within each class.

X. PROPOSED TARIFFS

Q. PLEASE DESCRIBE THE PROPOSED TARIFFS.

A. The tariff sheets are updated to reflect the new rates provided in Exhibit CRG-8. The tariff sheets have been provided in legislative and non-legislative format in Section 2.

XI. CONCLUSION

Q. DO THE PROPOSED RATES INCORPORATE THE RECOMMENDATIONS FROM THE CCOSS AND ALLOW BLACK HILLS POWER THE OPPORTUNITY TO COLLECT THE ADDITIONAL REVENUE REQUIREMENT OF $14,634,238?

A. Yes. These proposed rates will allow Black Hills Power the opportunity to recover the allowed revenue requirement level.

In addition, the proposed rates are aligned with the principles of rate design that the Company has used consistently throughout past rate cases. Black Hills Power has presented a reasonable CCOSS, which supports the proposed rate design.

Black Hills Power's proposed rate design is another step toward full cost of service rates for its customers, relying on gradualism to move customers towards that goal. The proposed rate design mitigates rate shock and balances individual customer class revenue requirement recovery impacts with cost based rates. Black Hills Power's proposed rate design results in just and reasonable rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Row No.						
1	***Residential Service***					
2	***Section 3, Sheet No. 1***		***SD710***			
3						
4	**Customer Charge**					
5	All Year	Regular Use	505,651	$	4,295,113	
6						
7	**Base Costs FPP/Transmsn.**			$	2,144,656	
8	**Environ. Improve. Adj**			$	489,327	
9	**Phase In Plan Rate**			$	463,882	
10	**Energy Efficiency Adjust**			$	279,397	
11						
12	**Energy Charge**					
13	All Year	All kWh	336,138,965	$	33,208,722	
14		**Total per Tariff sheet**	**336,138,965**			**$ 40,881,098**
15						
16						
17	***Residential - Total Electric Service***					
18	***Section 3, Sheet No. 3***		***SD712***			
19						
20	**Customer Charge**					
21	All Year		80,670	$	901,885	
22						
23	**Base Costs FPP/Transmsn.**			$	315,496	
24	**Environ. Improve. Adj**			$	146,409	
25	**Phase In Plan Rate**			$	87,592	
26	**Energy Efficiency Adjust**			$	76,599	
27						
28	**Energy Charge**					
29	All Year	All kWh	88,905,064	$	7,138,848	
30		**Total per Tariff sheet**	**88,905,064**			**$ 8,666,828**
31						
32						
33	***Residential - Demand Service***					
34	***Section 3A, Sheet No. 1***		***SD714***			
35						
36	**Customer Charge**					
37	All Year		10,198	$	140,149	
38						
39	**Capacity Charge (kW)**		112,052	$	775,070	
40						
41	**Base Costs FPP/Transmsn.**			$	74,412	
42	**Environ. Improve. Adj**			$	32,588	
43	**Phase In Plan Rate**			$	20,188	
44	**Energy Efficiency Adjust**			$	17,150	
45						
46	**Energy charge**					
47	All Year	All kWh	19,940,176	$	728,376	
48		**Total per Tariff sheet**	**19,940,176**			**$ 1,787,933**
49						
50						
51	***Residential - Demand Service (Maximum Value Option)***					
52	***Section 3A, Sheet No. 1***		***SD716***			
53						
54	**Customer Charge**					
55	All Year		32,737	$	449,996	
56						
57	**Capacity Charge (kW)**		314,209	$	2,181,338	
58						
59	**Base Costs FPP/Transmsn.**			$	258,991	
60	**Environ. Improve. Adj**			$	115,856	
61	**Phase In Plan Rate**			$	71,202	
62	**Energy Efficiency Adjust**			$	60,836	
63						
64	**Base Rate charge**					
65	All Year	All kWh	70,704,603	$	2,586,992	
66		**Total per Tariff sheet**	**70,704,603**			**$ 5,725,211**
67						
68						
69	***Residential - Utility Controlled Service***					
70	***Section 3A, Sheet No. 4***		***SD717***			
71						
72	**Customer Charge**					
73	All Year		33	$	224	
74						
75	**Base Costs FPP/Transmsn.**			$	456	
76	**Environ. Improve. Adj**			$	215	
77	**Phase In Plan Rate**			$	128	
78	**Energy Efficiency Adjust**			$	114	
79						
80	**Energy Charge**					
81	All Year	All kWh	131,002	$	6,729	
82		**Total per Tariff sheet**	**131,002**			**$ 7,866**
83						
84						
85	***Residential - Net Billing - Regular Service***					
86	***Section 3B, Sheet No. 4 (SD710)***		***SD875***			
87						
88	**Customer Charge**					
89	All Year	Regular Use	75	$	644	

Row No.							
90							
91	**Base Costs FPP/Transmsn.**			$	357		
92	**Environ. Improve. Adj**			$	91		
93	**Phase In Plan Rate**			$	80		
94	**Energy Efficiency Adjust**			$	51		
95							
96	**Energy Charge**						
97	All Year	All kWh	60,839	$	6,026		
98		**Total per Tariff sheet**	**60,839**			**$**	**7,249**
99							
100							
101	***Residential - Net Billing - Total Electric***						
102	***Section 3B, Sheet No. 4 (SD712)***		***SD876***				
103							
104	**Customer Charge**						
105	All Year	Regular Use	24	$	269		
106							
107	**Base Costs FPP/Transmsn.**			$	71		
108	**Environ. Improve. Adj**			$	30		
109	**Phase In Plan Rate**			$	20		
110	**Energy Efficiency Adjust**			$	16		
111							
112	**Energy Charge**						
113	All Year	All kWh	18,621	$	1,492		
114		**Total per Tariff sheet**	**18,621**			**$**	**1,898**
115							
116							
117	***Residential - Net Billing - Demand - Max Value***						
118	***Section 3B, Sheet No. 1 (SD716)***		***SD887***				
119							
120	**Customer Charge**						
121	All Year		12	$	147		
122							
123	**Capacity Charge (kW)**		119	$	818		
124							
125	**Base Costs FPP/Transmsn.**			$	117		
126	**Environ. Improve. Adj**			$	32		
127	**Phase In Plan Rate**			$	28		
128	**Energy Efficiency Adjust**			$	18		
129							
130	**Base Rate charge**						
131	All Year	All kWh	21,270	$	744		
132		**Total per Tariff sheet**	**21,270**			**$**	**1,904**
133							
134							
135							
136	***Small General Service - Total Electric (No Demand)***						
137	***Section 3, Sheet No.9***		***SD703***				
138							
139	**Customer Charge**						
140	All Year		158	$	2,602		
141							
142	**Base Costs FPP/Transmsn.**			$	-		
143	**Environ. Improve. Adj**			$	119		
144	**Phase In Plan Rate**			$	-		
145	**Energy Efficiency Adjust**			$	41		
146							
147	**Energy Charge**						
148	All Year	First 6000 kWh's	64,143	$	4,766		
149	All Year	All additional kW	-	$	-		
150		**Total per Tariff sheet**	**64,143**			**$**	**7,529**
151							
152							
153	***SGS - Athletic Fields (off-peak)***						
154	***Section 3, Sheet No.7***		***SD718***				
155							
156	**Customer Charge**						
157	All Year		533	$	6,146		
158							
159	**Base Costs FPP/Transmsn.**			$	6,374		
160	**Environ. Improve. Adj**			$	1,149		
161	**Phase In Plan Rate**			$	1,725		
162	**Energy Efficiency Adjust**			$	549		
163							
164	**Energy Charge**						
165	All Year	First 1,000 kWh	254,738	$	27,565		
166	All Year	Next 2,000 kwh	238,550	$	22,043		
167	All Year	Next 12,000 kWh	206,488	$	16,631		
168	All Year	All additional kWh	67,200	$	4,015		
169		**Total per Tariff sheet**	**766,976**			**$**	**86,196**
170							
171							
172	***SGS - Demand Not Billed (off-peak)***						
173	***Section 3, Sheet No.7***		***SD719***				
174							
175	**Customer Charge**						
176	All Year		4,134	$	45,475		
177							
178	**Minimum Bill**			$	-		
179							

Row No.					
180	**Base Costs FPP/Transmsn.**			$ -	
181	**Environ. Improve. Adj**			$ 2,779	
182	**Phase In Plan Rate**			$ 0	
183	**Energy Efficiency Adjust**			$ 970	
184					
185	**Energy Charge**				
186	All Year	First 1,000 kWh	1,112,279	$ 123,018	
187	All Year	Next 2,000 kwh	94,285	$ 9,033	
188	All Year	Next 12,000 kWh	1,128	$ 96	
189	All Year	All additional kWh	-	$ -	
190		**Total per Tariff sheet**	**1,207,692**		**$ 181,370**
191					
192					
193	***Small General Service***				
194	***Section 3, Sheet No.7***		***SD720***		
195					
196	**Customer Charge**				
197	All Year		124,047	$ 1,427,551	
198					
199	**Capacity Charge**				
200	All Year	First 5 kW	401,125	$ -	
201	All Year	Next 45 kW	756,976	$ 5,160,634	
202	All Year	Additional kW	226,023	$ 1,456,187	
203					
204	**Minimum Bill**			$ 1,353	
205					
206	**Base Costs FPP/Transmsn.**			$ 2,211,448	
207	**Environ. Improve. Adj**			$ 610,922	
208	**Phase In Plan Rate**			$ 568,571	
209	**Energy Efficiency Adjust**			$ 254,851	
210					
211	**Energy Charge**				
212	All Year	First 1,000 kWh	72,860,730	$ 7,922,233	
213	All Year	Next 2,000 kwh	71,093,438	$ 6,621,352	
214	All Year	Next 12,000 kWh	132,786,844	$ 10,823,702	
215	All Year	All additional kWh	76,531,080	$ 4,970,891	
216		**Total per Tariff sheet**	**353,272,092**		**$ 42,029,694**
217					
218					
219	***Small General Service - Total Electric***				
220	***Section 3, Sheet No.9***		***SD723***		
221					
222	**Customer Charge**				
223	All Year		10,421	$ 180,463	
224					
225	**Capacity Charge**				
226	All Year	First 5 kW	44,210	$ -	
227	All Year	Next 45 kW	98,812	$ 612,616	
228	All Year	Additional kW	20,720	$ 117,951	
229					
230	**Base Costs FPP/Transmsn.**			$ 198,757	
231	**Environ. Improve. Adj**			$ 69,361	
232	**Phase In Plan Rate**			$ 55,207	
233	**Energy Efficiency Adjust**			$ 28,028	
234					
235	**Energy Management Fee**			$ (864)	
236					
237	**Energy Charge**				
238	All Year	First 6,000 kWh	23,032,373	$ 1,641,028	
239	All Year	All additional kWh	15,056,977	$ 996,043	
240		**Total per Tariff sheet**	**38,089,350**		**$ 3,898,590**
241					
242					
243	***Irrigation Pumping***				
244	***Section 3, Sheet No. 19***		***SD726***		
245					
246	**Capacity Charge**				
247	Per season per horsepower of connected load		1,371	$ 20,587	
248					
249	**Base Costs FPP/Transmsn.**			$ 11,839	
250	**Environ. Improve. Adj**			$ 1,023	
251	**Phase In Plan Rate**			$ 2,394	
252	**Energy Efficiency Adjust**			$ 551	
253					
254	**Energy Charge**				
255	All Year	All kWh	887,365	$ 61,207	
256		**Total per Tariff sheet**	**887,365**		**$ 97,602**
257					
258					
259	***Small General Service - Utility Controlled Service***				
260	***Section 3A, Sheet No. 11***		***SD727***		
261					
262	**Customer Charge**				
263	All Year		282	$ 1,757	
264					
265	**Base Costs FPP/Transmsn.**			$ 7,919	
266	**Environ. Improve. Adj**			$ 4,739	
267	**Phase In Plan Rate**			$ 2,008	
268	**Energy Efficiency Adjust**			$ 1,802	
269	**Energy Charge**				

Row No.							
270	All Year	All kWh	2,375,455	$	121,333		
271		**Total per Tariff sheet**	**2,375,455**			**$**	**139,558**
272							
273							
274	***Traffic Signals***						
275	***Section 3, Sheet No. 26***		***SD742***				
276							
277	**Customer Charge**		1,765	$	14,699		
278							
279	**Base Costs FPP/Transmsn.**			$	3,632		
280	**Environ. Improve. Adj**			$	1,340		
281	**Phase In Plan Rate**			$	868		
282	**Energy Efficiency Adjust**			$	519		
283							
284	**Base Rate charge**						
285	All Year	All kWh	706,762	$	53,087		
286		**Total per Tariff sheet**	**706,762**			**$**	**74,146**
287							
288							
289	***Municipal Pumping***						
290	***Section 3, Sheet No. 24***		***SD743***				
291							
292	**Customer Charge**						
293	Winter 11/1 to 5/31	Regular Use	668	$	11,026		
294	Summer 6/1 to 10/31	Regular Use	502	$	9,031		
295							
296	**Capacity Charge**						
297	Winter 11/1 to 5/31	Per kW	20,037	$	81,751		
298	Summer 6/1 to 10/31	Per kW	47,767	$	228,655		
299							
300	**Base Costs FPP/Transmsn.**			$	163,790		
301	**Environ. Improve. Adj**			$	38,802		
302	**Phase In Plan Rate**			$	41,424		
303	**Energy Efficiency Adjust**			$	16,619		
304	**Energy Charge**						
305	Winter 10/1 to 5/31	All kWh	11,715,085	$	708,763		
306	Summer 6/1 to 9/30	All kWh	11,658,031	$	594,918		
307		**Total per Tariff sheet**	**23,373,116**			**$**	**1,894,777**
308							
309							
310	***Small Interruptible General Service***						
311	***Section 3A, Sheet No. 18***		***SD750***				
312							
313	**Customer Charge**						
314	All Year		50	$	564		
315							
316	**Capacity Charge (kW)**		3,447	$	2,752		
317							
318	**Base Costs FPP/Transmsn.**			$	2,208		
319	**Environ. Improve. Adj**			$	285		
320	**Phase In Plan Rate**			$	511		
321	**Energy Efficiency Adjust**			$	144		
322	**Base Rate charge**						
323	All Year	All kWh	211,580	$	9,256		
324		**Total per Tariff sheet**	**211,580**			**$**	**15,720**
325							
326							
327	***Energy Storage***						
328	***Section 3A, Sheet No. 6***		***SD755***				
329							
330	**Customer Charge**						
331	All Year		242	$	2,884		
332							
333	**Capacity Charge (kW)**						
334	All Year	On-Peak	14,720	$	118,257		
335	All Year	Off-Peak	29,386	$	-		
336							
337	**Base Costs FPP/Transmsn.**			$	24,879		
338	**Environ. Improve. Adj**			$	7,982		
339	**Phase In Plan Rate**			$	6,626		
340	**Energy Efficiency Adjust**			$	3,504		
341							
342	**Energy Charge (kWh)**						
343	All Year	On-Peak	2,032,274	$	97,494		
344	All Year	Off-Peak	2,768,305	$	74,664		
345		**Total per Tariff sheet**	**4,800,579**			**$**	**336,291**
346							
347							
348	***SGS - Special Events***						
349	***Section 3, Sheet No.7***		***SD770***				
350							
351	**Customer Charge**						
352	All Year		1,281	$	15,552		
353							
354	**Capacity Charge**						
355	All Year	First 5 kW	1,871	$	-		
356	All Year	Next 45 kW	4,044	$	31,414		
357	All Year	Additional kW	1,412	$	10,548		
358							
359	**Base Costs FPP/Transmsn.**			$	16,690		

Row No.						
360	**Environ. Improve. Adj**			$	529	
361	**Phase In Plan Rate**			$	2,649	
362	**Energy Efficiency Adjust**			$	361	
363						
364	**Energy Charge**					
365	All Year	First 1,000 kWh	269,419	$	28,184	
366	All Year	Next 2,000 kwh	221,930	$	19,165	
367	All Year	Next 12,000 kWh	293,432	$	21,447	
368	All Year	All additional kWh	34,520	$	1,891	
369			**819,301**			**$ 148,431**
370						
371						
372	***SGS - Net Billing (SD720)***					
373	***Section 3B, Sheet No.4***		***SD878***			
374						
375	**Customer Charge**					
376	All Year		97	$	1,119	
377						
378	**Capacity Charge**					
379	All Year	First 5 kW	327	$	-	
380	All Year	Next 45 kW	459	$	3,028	
381	All Year	Additional kW	14	$	84	
382						
383	**Base Costs FPP/Transmsn.**			$	479	
384	**Environ. Improve. Adj**			$	193	
385	**Phase In Plan Rate**			$	131	
386	**Energy Efficiency Adjust**			$	75	
387						
388	**Energy Charge**					
389	All Year	First 1,000 kWh	45,368	$	4,928	
390	All Year	Next 2,000 kwh	46,071	$	4,315	
391	All Year	Next 12,000 kWh	10,900	$	812	
392	All Year	All additional kWh	-	$	-	
393		**Total per Tariff sheet**	**102,339**			**$ 15,164**
394						
395						
396						
397						
398	***General Service Large - Secondary Service***					
399	***Section 3, Sheet No.11***		***SD721***			
400						
401	**Capacity Charge**					
402	All Year	On-Peak - First 125 kVa	1,230	$	1,514,152	
403	All Year	On-Peak - Each Addl kVA	137,527	$	1,088,720	
404	All Year	Off-Peak - >250 kVA - no charge	-	$	-	
405	All Year	Off-Peak - 1.5x Billing Capacity	-	$	-	
406						
407	**Base Costs FPP/Transmsn.**			$	780,373	
408	**Environ. Improve. Adj**			$	149,519	
409	**Phase In Plan Rate**			$	147,486	
410	**Energy Efficiency Adjust**			$	90,819	
411						
412	**Substation Lease**			$	-	
413						
414	**Energy Charge**					
415	All Year	First 50,000 kWh	56,128,845	$	2,988,050	
416	All Year	Next 450,000 kwh	41,544,430	$	2,102,990	
417	All Year	All additional kWh	379,700	$	12,834	
418		**Total per Tariff sheet**	**98,052,975**			**$ 8,874,943**
419						
420						
421	***General Service Large - Primary Service***					
422	***Section 3, Sheet No.11***		***SD721***			
423						
424	**Capacity Charge**					
425	All Year	On-Peak - First 125 kVa	60	$	73,100	
426	All Year	On-Peak - Each Addl kVA	52,650	$	414,530	
427	All Year	Off-Peak - >250 kVA - no charge	-	$	-	
428	All Year	Off-Peak - 1.5x Billing Capacity	-	$	-	
429						
430	**Base Costs FPP/Transmsn.**			$	-	
431	**Environ. Improve. Adj**			$	-	
432	**Phase In Plan Rate**			$	-	
433	**Energy Efficiency Adjust**			$	-	
434						
435	**Substation Lease**			$	(10,876)	
436						
437	**Energy Charge**					
438	All Year	First 50,000 kWh	3,000,000	$	161,095	
439	All Year	Next 450,000 kwh	9,704,042	$	505,622	
440	All Year	All additional kWh	14,898,000	$	709,249	
441		**Total per Tariff sheet**	**27,602,042**			**$ 1,852,720**
442						
443						
444	***General Service Large - Large Demand Curtailable Service (Closed)***					
445	***Section 3A, Sheet No. 13***		***SD722***			
446						
447	**Capacity Charge**					
448	All Year	Per kVA	2,902	$	36,769	
449						
450	**Base Costs FPP/Transmsn.**			$	5,403	
451	**Environ. Improve. Adj**			$	1,241	

Phase In Plan Rate			$	1,096	
Energy Efficiency Adjust			$	725	
Curtailable Load Credit		2,902	$	(20,130)	
Energy Charge					
All Year	All kWh	998,721	$	39,987	
	Total per Tariff sheet	**998,721**			**$ 65,091**
General Service Large - Secondary Service - Combined Billing					
Section 3, Sheet No. 33		***SD752***			
Service Charge					
Per Location		1,732	$	157,206	
Capacity Charge					
All Year	First 125 kVa	499	$	615,967	
All Year	Each Addl kVA	360,830	$	2,849,522	
Base Costs FPP/Transmsn.			$	902,145	
Environ. Improve. Adj			$	186,336	
Phase In Plan Rate			$	174,778	
Energy Efficiency Adjust			$	111,255	
Phone Charge/Equipment Rental			$	4,019	
Energy Charge					
All Year	First 50,000 kWh	24,779,800	$	1,309,826	
All Year	Next 450,000 kwh	90,013,259	$	4,642,855	
All Year	All additional kWh	39,078,591	$	1,859,299	
	Total per Tariff sheet	**153,871,650**			**$ 12,813,208**
General Service Large - Secondary Service - Combined Billing					
Section 3, Sheet No. 33		[redacted]			
Service Charge					
Per Location		[redacted]			
Capacity Charge					
All Year	First 125 kVa				
All Year	Each Addl kVA				
Base Costs FPP/Transmsn.					
Environ. Improve. Adj					
Phase In Plan Rate					
Energy Efficiency Adjust					
Phone Charge/Equipment Rental					
Energy Charge					
All Year	First 50,000 kWh				
All Year	Next 450,000 kwh				
All Year	All additional kWh				
	Total per Tariff sheet				
Large Power Contract Service - Secondary Service - Combined Billing					
Section 3, Sheet No. 31	Special Contract	[redacted]			
Service Charge					
Flat Monthly Charge		[redacted]			
Capacity Charge					
All Year	Peak Monthly kVa				
All Year	Billed Contract kVA				
Base Costs FPP/Transmsn.					
Environ. Improve. Adj					
Phase In Plan Rate					
Energy Efficiency Adjust					
Phone Charge/Equipment Rental					
Energy Charge					
All Year	First 3,000,000 kWh				
All Year	All additional kWh				
	Total per Tariff sheet				
Special Contract - Industrial 69 kV Service					
Section 3, Sheet No. 14					
Capacity Charge					
All Year	On Peak				
Base Costs FPP/Transmsn.					
Environ. Improve. Adj					
Phase In Plan Rate					

Row No.			
544	**Energy Efficiency Adjust**		[redacted]
545			
546	**Energy Charge**		
547	All Year	All kWh @ 69 kV Service	
548		**Total per Tariff sheet**	
549			
550			
551	***Special Contract - Forest Products - Industrial Primary***		
552	***Section 3, Sheet No. 36***		
553			
554	**Capacity Charge**		
555	All Year	First 2,000 kVA	
556	All Year	Next 3,000 kVA	
557	All Year	Each Additional kVA	
558			
559	**Base Costs FPP/Transmsn.**		
560	**Environ. Improve. Adj**		
561	**Phase In Plan Rate**		
562	**Energy Efficiency Adjust**		
563			
564	**Energy Charge**		
565	All Year	First 800,000 kWh	
566	All Year	First 1,200,000 kWh	
567	All Year	Each Additional kWh	
568		**Total per Tariff sheet**	
569			
570			
571	***Special Contract - Forest Products - Industrial Secondary***		
572	***Section 3, Sheet No. 36***		
573			
574	**Capacity Charge**		
575	All Year	First 2,000 kVA	
576	All Year	Next 3,000 kVA	
577	All Year	Each Additional kVA	
578			
579	**Base Costs FPP/Transmsn.**		
580	**Environ. Improve. Adj**		
581	**Phase In Plan Rate**		
582	**Energy Efficiency Adjust**		
583			
584	**Energy Charge**		
585	All Year	First 800,000 kWh	
586	All Year	First 1,200,000 kWh	
587	All Year	Each Additional kWh	
588		**Total per Tariff sheet**	
589			
590			
591	***Special Contract - General Service Large 69 kV Service***		
592	***Section 3, Sheet No.11***		
593			
594	**Capacity Charge**		
595	All Year	On-Peak - First 125 kVA	
596	All Year	On-Peak - Each Addl kVA	
597			
598	**Base Costs FPP/Transmsn.**		
599	**Environ. Improve. Adj**		
600	**Phase In Plan Rate**		
601	**Energy Efficiency Adjust**		
602	**Substation Lease**		
603			
604	**Energy Charge**		
605	All Year	First 50,000 kWh	
606	All Year	Next 450,000 kwh	
607	All Year	All additional kWh	
608		**Total per Tariff sheet**	
609			
610			
611	***Special Contract - Forest Products - Industrial Primary***		[redacted]
612	***Section 3, Sheet No. 36***		
613			
614	**Capacity Charge**		[redacted]
615	All Year	First 2,000 kVA	
616	All Year	Next 3,000 kVA	
617	All Year	Each Additional kVA	
618			
619	**Base Costs FPP/Transmsn.**		
620	**Environ. Improve. Adj**		
621	**Phase In Plan Rate**		
622	**Energy Efficiency Adjust**		
623			
624	**Energy Charge**		
625	All Year	First 800,000 kWh	
626	All Year	First 1,200,000 kWh	
627	All Year	Each Additional kWh	
628		**Total per Tariff sheet**	
629			
630			
631			
632			
633	***Private or Public Area Lighting Service - Standard***		
634	***Section 3, Sheet No. 16***		***SDA24***
635			

Row No.						
636	**Base Costs FPP/Transmsn.**			$	15,469	
637	**Environ. Improve. Adj**			$	5,927	
638	**Phase In Plan Rate**			$	3,576	
639	**Energy Efficiency Adjust**			$	2,254	
640						
641	**Base Rate charge**					
642	All Year	All kWh	3,077,091	$	391,862	
643		**Total per Tariff sheet**	**3,077,091**			**$ 419,088**
644						
645						
646	***Private or Public Area Lighting Service - Flood Lighting***					
647	***Section 3, Sheet No. 16***		***SDB24***			
648						
649	**Base Costs FPP/Transmsn.**			$	3,370	
650	**Environ. Improve. Adj**			$	1,435	
651	**Phase In Plan Rate**			$	795	
652	**Energy Efficiency Adjust**			$	539	
653						
654	**Base Rate charge**					
655	All Year	All kWh	729,344	$	133,811	
656		**Total per Tariff sheet**	**729,344**			**$ 139,950**
657						
658						
659	***Private or Public Area Lighting Service - Customer Owned***					
660	***Section 3, Sheet No. 17***		***SDC24***			
661						
662	**Base Costs FPP/Transmsn.**			$	680	
663	**Environ. Improve. Adj**			$	250	
664	**Phase In Plan Rate**			$	154	
665	**Energy Efficiency Adjust**			$	95	
666						
667	**Base Rate charge**					
668	All Year	All kWh	131,472	$	8,520	
669		**Total per Tariff sheet**	**131,472**			**$ 9,700**
670						
671						
672	***Customer Owned Street Lighting - Energy Only***					
673	***Section 3, Sheet No. 22***		***SD741***			
674						
675	**Base Costs FPP/Transmsn.**			$	27,353	
676	**Environ. Improve. Adj**			$	11,495	
677	**Phase In Plan Rate**			$	6,354	
678	**Energy Efficiency Adjust**			$	4,337	
679						
680	**Base Rate charge**					
681	All Year	All kWh	5,872,811	$	369,911	
682		**Total per Tariff sheet**	**5,872,811**			**$ 419,449**
683						
684						
685	***Company Owned Street Lighting***					
686	***Section 3, Sheet No. 22***		***SD840***			
687						
688	**Base Costs FPP/Transmsn.**			$	16,712	
689	**Environ. Improve. Adj**			$	6,998	
690	**Phase In Plan Rate**			$	3,866	
691	**Energy Efficiency Adjust**			$	2,641	
692						
693	**Base Rate charge**					
694	All Year	All kWh	3,577,040	$	724,322	
695		**Total per Tariff sheet**	**3,577,040**			**$ 754,539**
696						
697						
698	***Customer Owned Street Lighting - Energy and Maintenance***					
699	***Section 3, Sheet No. 22***		***SD841***			
700						
701	**Base Costs FPP/Transmsn.**			$	575	
702	**Environ. Improve. Adj**			$	220	
703	**Phase In Plan Rate**			$	130	
704	**Energy Efficiency Adjust**			$	82	
705						
706	**Base Rate charge**					
707	All Year	All kWh	114,226	$	9,693	
708		**Total per Tariff sheet**	**114,226**			**$ 10,701**
709						
710						
711						
712	***Rental***					
713	***Section 3, Sheet No. 22***		**SD798/SD799**			
714						
715	**Capacity Charge**			$	240	
716	**Equip. Rental Charge**			$	600	
717	**Facilities/Rental Charge**			$	54,007	
718	**Miscellaneous Fee's**			$	4,096	
719						
720						
721		**Total per Tariff sheet**	**-**			**$ 58,943**
722						
723						
724						
725	***TOTAL RATES***		**1,483,797,944**			**$ 146,724,130**