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. PURPOSE OF TESTIMONY

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. <u>PHASE IN PLAN RATE REVENUE</u>

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. <u>DECOMMISSIONING REGULATORY ASSET</u>

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.