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. <u>PURPOSE OF TESTIMONY AND EXHIBITS</u>

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. <u>PRO FORMA REVENUE ADJUSTMENTS</u>

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 Electric Utility Cost Allocation Manual ("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. PROPOSED RATES

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.