Direct Testimony and Exhibits
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. EL12-___

December 17, 2012

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EXHIBITS

I. BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael J. Fredrich, 409 Deadwood Avenue, P.O. Box 1400, Rapid City, South Dakota, 57701.

Q. WHAT IS YOUR OCCUPATION?

A. I am an electrical engineer employed by Black Hills Utility Holdings Company as Director, Engineering Services.

Q. PLEASE DESCRIBE YOUR EDUCATION AND TRAINING.

A. I graduated from the South Dakota School of Mines and Technology with a Bachelor of Science Degree in Electrical Engineering in 1981. Since my employment with Black Hills Corporation, I have held the following positions: 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 and provided project engineering on a number of projects associated with control and protective relaying for the generating plants and the transmission system at Black Hills Power, Inc. ("Black Hills Power" or the "Company"). From 1987 to 1988, I served as the Substation Maintenance Supervisor for Black Hills Power's Electric Operations Department and was responsible for the operation and maintenance of the transmission system electrical equipment.

I also conducted in-house power flow studies associated with the Black Hills Power 230 kV and 69 kV transmission networks.

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. I also participated in joint transmission studies with Basin Electric Power Cooperative, Rushmore Electric Power Cooperative, Powder River Energy Cooperative, Black Hills Electric Cooperative and Butte Electric Cooperative, who have load served from the 230 kV and 69 kV transmission network within the Black Hills Power electrical network footprint.

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.

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 Black Hills Corporation, 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, and 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, and to provide additional detailed information in the following specific areas in support of this Black Hills Power Rate filing: distribution reliability and growth; increases in vegetation management brought on by the mountain pine beetle infestation; increased Company costs related to increased federal regulation; and Advanced Metering Infrastructure (AMI) metering.

III. SERVICE TERRITORY AND TRANSMISSION SYSTEM

Q. WHAT IS THE LOCATION OF BLACK HILLS POWER'S SERVICE TERRITORY AND TRANSMISSION SYSTEM?

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)

Q. PLEASE DESCRIBE BLACK HILLS POWER'S ELECTRIC SYSTEM.

A. The electric system utilized by Black Hills Power consists of a common use transmission system with approximately 570 miles of 230 kV transmission lines, a sub-transmission system with approximately 500 miles of lower-voltage 69 kV and 47 kV, and approximately 2,450 miles of distribution lines. Black Hills Power is interconnected with the Western Area Power Administration (WAPA) Rocky Mountain Regions' west 230 kV bus at

Stegall, Nebraska located near Scottsbluff, Nebraska; with PacifiCorp at the Wyodak Plant located near Gillette, Wyoming and the Dave Johnston substation located near Casper, Wyoming; and with WAPA's Upper Great Plains Region, through the Rapid City AC-DC-AC Tie, which was placed into service in October 2003.

Q. DOES BLACK HILLS POWER SHARE THE USE OF ITS TRANSMISSION SYSTEM WITH OTHERS?

A. Yes. Black Hills Power owns 230 kV facilities in South Dakota, Wyoming, and Nebraska and 69 kV facilities in South Dakota, Wyoming, and Montana. The 69 kV facilities that are located in South Dakota are utilized to distribute the Black Hills Power energy resources to its customer loads. In addition, these 69 kV sub-transmission facilities are utilized by the area South Dakota Cooperatives (Rushmore Electric Power Cooperative, Black Hills Electric Power Cooperative, and Butte Electric Cooperative) to wheel their energy to their respective loads located within the same geographical areas of western South Dakota. Black Hills Power makes similar use of cooperative sub-transmission facilities through a joint use agreement.

Q. DOES BLACK HILLS POWER CO-OWN 230 kV AND 69 kV LINES?

A. Yes. In order to efficiently serve customer needs in the region and avoid costly and inefficient infrastructure, Black Hills Power is co-owner of 230 kV and 69 kV transmission lines in South Dakota and Wyoming. Co-owners include

Basin Electric Power Cooperative (Basin Electric), Black Hills Electric Cooperative, Butte Electric Cooperative , and Tri-County Electric Association, Inc. (currently known as Powder River Energy Corporation, Inc. (PRECorp)).

Q. WHY DOES THE COMPANY CO-OWN LINES OR ALLOW OTHERS TO USE THE COMPANY LINES?

A. The above mentioned parties have historically, since the 1980's, performed joint planning studies in an effort to plan, construct, operate and finance the necessary 230 & 69 kV infrastructure required to serve the loads within this region. This joint coordination effort with others results in the efficient use of capital to serve the region. By working together, Black Hills Power and others have been able to avoid the duplication of facilities.

IV. DISTRIBUTION GROWTH & RELIABILITY

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 AND TRANSMISSION SYSTEMS?

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 Black Hills Power customers.

Q. IS THERE A DISTINCTION BETWEEN A "REBUILD" PROJECT AND A NEW LINE PROJECT? IF SO, PLEASE EXPLAIN.

A. Yes. Typically, when the Company refers to "rebuild" line projects, it has made an engineering determination that an existing line facility must be upgraded because it can no longer provide the load carrying capacity to meet the existing and forecasted load growth in the area, either during system intact conditions or during specific outage conditions. Rebuild projects typically require an increase in the size of the line conductor to allow for increased current capacity and this in turns requires a different structure to support the increased physical weight of the conductor. At Black Hills Power, a 69kV line rebuild project is essentially replacement of existing lines with new line construction utilizing the same right-of-way easement. In comparison, a new line project generally means constructing a new line on a new right-of-way.

Q. PLEASE IDENTIFY RECENT CAPITAL PROJECTS AND ADDRESS RELIABILITY AND LONG-TERM GROWTH NEEDS.

A. The following provides a brief description of some of the major 69 kV and distribution capital investments made to the Black Hills Power system that have been required to address various reliability and long term growth issues and that are included as part of this rate case.

1. <u>Minnekahta 230/69 kV Substation Addition.</u>

This project included the construction of a 230 kV and 69 kV substation with a 70 MVA 230/69 kV transformer. This substation and associated equipment was required to provide support to serve the Black Hills Power loads in the Hot Springs, Pringle, Argyle, Edgemont and Custer service area, all of which are part of what the company commonly refers to as the "Southern Hills" territory. In addition, this substation also provides service to Black Hills Electric Cooperative loads served from these same 69kV facilities. These loads had been previously served from essentially a single sourced location from the Company's West Hill 230/69kV 50 MVA substation location in Hot Springs. The Company had reached the limit of its ability to reliably serve these Southern Hills loads if the Company would have lost the West Hill source prior to having the Minnekahta substation. This project was placed in service in December, 2011.

2. <u>69 kV Line Rebuild Projects</u>

There are a number of 69kV line rebuild projects that have been recently completed to increase load carrying capacity in order to provide load service to the various loads served from these facilities during various system outage conditions and to meet projected load growth into the future.

a. Edgemont River to Hot Springs 69 kV Rebuild - This is an 18.41 mile, 69 kV rebuild project between Edgemont City and Hot Springs in the Company's Southern Hills service area. This line was identified in the Company's planning studies as needing to be upgraded to a larger conductor in order to continue to provide reliable service to the existing and forecasted loads served within the Southern Hills area during various system operating conditions. This line is also a jointly used and owned facility with Black Hills Electric Cooperative, as allowed under the Company's joint 69kV agreement (Agreement for Management, Operation, and Maintenance and Cost Sharing of the South Dakota 69 kV Distribution System). Under this agreement, Black Hills Electric owns an undivided 57.86% interest and Black Hills Power owns an undivided 42.14% interest in the 69kV line. Black Hills Power's undivided interest in this line segment has been included as a capital asset in this rate case filing. This project was placed in service in October, 2011.

b. Lange to Sturgis 69 kV Rebuild – This is a 25.5 mile, 69 kV rebuild project between Rapid City and Sturgis. This line was identified in the Company's planning studies as needing to be upgraded to a larger conductor in order to continue to provide reliable service to the existing and forecasted loads served within the Northern Hills area during various system operating conditions. This line is also a jointly used and owned facility with Butte Electric Cooperative as allowed for under the Company's joint 69kV agreement (Agreement for Management, Operation, and Maintenance and Cost Sharing of the South Dakota 69 kV Distribution System). Under this agreement, Butte Electric owns an undivided 20.99% interest and Black Hills Power owns an undivided 79.01% interest. Black Hills Power's undivided interest in this line segment has been included as a capital asset in this rate case filing. This project was placed in service in June, 2011.

c. Windy Flats to Pactola 69 kV Rebuild – This is a rebuild of approximately 16 miles of an existing 69 kV line segment associated between the Pactola Substation and a substation tap located at Windy Flats. This line was originally constructed in 1948 with 2/0F CWC type conductor with unshielded type line construction. This line segment was rebuilt with 795 ACSR conductor along with associated static wire protection. The change in conductor size increased the current carrying capacity of the line from 350 Amps to 900 Amps and the addition of the static wire provided increase lightning protection to the line. This 69 kV rebuild project completed the rebuilding of the entire 69 kV Yellow Creek-Windy Flats-Pactola line segment. This line is utilized to directly serve customer loads in the Lead/Deadwood, Windy Flats, and Pactola areas, as well as providing additional load service capacity to the entire Northern Hills, Southern Hills and Rapid City areas during various operating and outage conditions. This project was placed in service in December, 2008.

d. Whitewood to Piedmont 69 kV Rebuild – This is a rebuild of approximately 17 miles of an existing 69 kV line segment between the Whitewood substation and the Piedmont 69 kV line tap. This line was originally constructed in 1971 with 336 ACSR type conductor. This line segment was rebuilt with 795 ACSR conductor and was the last line segment between the Lange and Whitewood Substations to be rebuilt with 795 ACSR conductor. The change in conductor size increased the current carrying capacity of the line from 530 Amps to 900 Amps. This 69 kV rebuild project completed the rebuilding of the entire 31 mile line segment between the Lange Substation (Rapid City) and the Whitewood substation. The entire line from Lange-Piedmont-Sturgis-Whitewood provides additional load service capability to the loads served in the Northern Hills, Sturgis/Whitewood, and Rapid City areas during various operating and outage conditions. This project was placed in service in March, 2010.

3. <u>230/69kV Transformer Replacements</u>

There is a major 230/69kV transformer upgrade project completed during the rate case test year regarding one of the two transformers located at the Wyodak substation. This project involved the replacement of a 230/69kV 70 MVA transformer to a larger 230/69kV 100 MVA transformer. This project was identified through our transmission planning efforts as being required to allow for the overloading of the smaller 70 MVA transformer for outages of the larger 100 MVA transformer. Both of these transformers operate in parallel and are critical to the overall operation and stability of the entire Black Hills Power transmission network as they provide a transmission path from the Black Hills Power generation located at this site to the Black Hills Power's loads served in South Dakota. This project was placed in service in April, 2012.

4. <u>Distribution Substation Additions</u>

There are three major distribution substation additions that are included in this rate case. One substation addition is currently in-service and the other two are either near completion and/or will be placed into service no later than March 31, 2013. Two of these substations are located in Rapid City and the other is located in Spearfish. All three of these substation additions were identified by the Company's distribution planning studies as being needed to provide reliable service to the customers served by these facilities and to meet projected load growth in the areas.

a. Cleveland Street Substation Addition & 5th Street Substation Additions (Two Substation Additions)

The 5th Street Substation project initially consisted of replacement of the existing two 69/12.4 kV transformers and associated switchgear due to and overloading concerns with the existing aging infrastructure and to meet the growing energy needs of businesses and neighborhoods in the South Rapid City area. This substation served residential, commercial, Rapid City Regional Hospital, and the additional medical center facilities located in that part of Rapid City. The loads in the area had grown large enough that should one of these transformers fail, the adjacent transformer would not have the capacity to pick up the load, nor would the Company have been able to pick up any of this load from nearby substations due to the distance and capacity limitations at those substation locations.

After investigation and discussions with various landowners, Black Hills Power was successful in obtaining a viable piece of property located approximately 2-3 blocks away from the existing 5th Street Substation to construct the Cleveland Street Substation.

Obtaining the Cleveland Street Substation site allowed the Company to construct and install one transformer originally planned for the 5th Street location and associated switchgear feeder equipment. This substation was placed in service in May, 2012 and is providing service the various residential, commercial and medical loads in the area.

The addition of the Cleveland Street Substation has allowed the Company to also rebuild and replace the existing transformer and switchgear at the existing 5th Street Substation with a larger similar sized transformer. The 5th Street Substation is expected to be placed in service in December, 2012.

The addition of the Cleveland Street Substation and the reconstruction of the existing 5th Street Substation, addressed existing capacity and reliability concerns by almost doubling the capacity in the area and included four additional feeders for reduced outage exposure and improved reliability.

b. Spearfish City Substation Rebuild

The Spearfish City Substation initially was a 69/4.16kV substation that served customer loads generally located in the downtown area of Spearfish, South Dakota. Black Hills Power had recently converted the 4.16 kV distribution facilities that were previously served from this substation to 12.47 kV voltages and thus the Spearfish loads were being served by two other 12.47 kV substation sites, commonly known as Spearfish Park and Hills View. The rebuild and conversion of the Spearfish City Substation will allow Black Hills Power to adequately provide backup service to the Spearfish City area during various outage conditions associated with the Hills View and Spearfish Park substations and their associated distribution feeder circuits. The Spearfish City distribution substation is planned to be placed in service in December, 2012. In addition, the Spearfish City Substation, Hills View, and Spearfish Park Substations will meet the additional load growth in that area.

5. <u>Betterment/Rebuild Projects</u>

Betterment and rebuild type projects are projects completed on the distribution network that have been identified through either operational issues or planning studies as being necessary to provide reliable service to the Company's customers. These typically include such projects as voltage regulators, reconductoring/line capacity upgrades, capacitor additions, substation conversions, underground replacement, and new feeder exit circuits.

Q. ARE THERE ANY OTHER SPECIFIC CAPITAL PROJECTS WHICH YOU WOULD LIKE TO DISCUSS?

A. Yes. In addition to the capital assets that have been identified above and already placed into service, there are two (2) additional specific 69 kV line rebuild projects to be constructed that are associated with the proposed Transmission Facility Adjustment tariff, which is described in the testimony of Chuck Loomis:

a. Custer to Hot Springs 69 kV line:

This project involves the rebuilding of approximately 25 miles of an existing 69 kV line that was constructed in 1954, because of its limited capacity rating due to the size of conductor. The existing conductor size is 3/0 ACSR with a current carrying capacity of approximately 300 amps and the new line construction will be 795 ACSR with a current carrying capacity of 900 amps. This increase in line carrying capacity will meet the needs of the customers served in this area for all operating and contingency planning conditions as it supports the loads served in Custer, Edgemont, and Hot Springs.

b. Lookout to Sundance Hill 69 kV line:

This project involves the rebuilding of an existing 69 kV line that was constructed in 1956. This line segment is being rebuilt due its limited conductor rating. The existing conductor size is 336 ACSR with a current carrying capacity of 530 amps and the new line construction will be 795 ACSR with a current carrying capacity of 900 amps. This line rebuild project, which is approximately 13 miles, is required to meet both the existing customer loads served in the Northern Hills area and to meet additional load growth requirements being imposed on Black Hills Power for loads served from our facilities located in Belle Fourche area during various operating and outage conditions.

V. VEGETATION MANAGEMENT

Q. WOULD YOU PLEASE PROVIDE A GENERAL OVERVIEW OF THE BLACK HILLS POWER VEGETATION MANAGEMENT PROGRAM?

A. Black Hills Power utilizes an integrated vegetation management approach by managing vegetation through manual, mechanical, herbicide and biological treatments for both its transmission and distribution systems. The expectation and procedures of this program are to provide and manage a suitable Right-Of-Way (ROW) clearance to control vegetation growth that could interfere with the safe and reliable delivery of electricity. Black Hills seeks to maintain a ten year vegetation maintenance cycle for the Company's 230 kV transmission and

69 kV sub-transmission power lines. A four (4) year trim cycle is sought for primary circuits with voltages less than 69 kV.

Q. ARE THERE ANY REGULATORY COMPLIANCE REQUIREMENTS FOR VEGETATION MANAGEMENT?

A. Yes. Black Hills is required to meet specific reliability compliance standards of the North American Electric Reliability Corporation (NERC) as it relates to vegetation management associated with the Company's 230 kV transmission facilities.

In addition, Black Hills Power's defined Distribution/Transmission Vegetation Management Program also follows arboricultural and minimum clearance standards for power lines per the following industry standards:

- American National Standards Institute (ANSI) Z133.1-2000 for Arboricultural Operations – Pruning, Repairing, Maintaining, and Removing Trees and Cutting Brush – Safety Requirements
- ANSI A300(Part 1)-2001 for Tree Care Operations – Tree Shrub, and Other Woody Plant Maintenance – Standard Practices (Pruning)
- "Best Management Practices – Utility Pruning of Trees." A companion publication to the ANSI A300 (Part 1).
- "Pruning Trees near Electric Utility Lines – a Field Pocket Guide" by Dr. Alex L. Shigo

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF THE TYPE OF VEGETATION WITHIN THE BLACK HILLS SERVICE TERRITORY?

A. The Black Hills forest in South Dakota is dominated by ponderosa pine and Black Hills spruce with areas of open prairie. In low lying areas, there are patches of cottonwood as well as oak. Urban environments have greater populations of elm, maple, and other ornamental species such as crab apple. In higher elevations there are pockets of aspen and birch.

Q. WHAT AMOUNT OF THE COMPANY'S SERVICE AREA IS EXPOSED TO VEGETATION?

A. Out of the Company's total transmission and distribution electrical network, we have estimated that we approximately 200 miles (or 35%) of 230 kV transmission line, 276 miles (or 30%) of 69 kV sub-transmission line and 1,800 miles (or 74%) of distribution line are exposed to vegetation.

Q. PLEASE CHARACTERIZE SOME OF THE MAJOR CHALLENGES FACED BY BLACK HILLS IN ACHIEVING IT'S DESIRED VEGETATION MANAGEMENT PROGRAM?

A. There has been an increase in annual average precipitation totals experienced throughout the entire Black Hills Service Territory. Exhibit MJF - 2 is a table of various precipitation monitoring locations in South Dakota and Wyoming.

As identified in this table, the average annual precipitation for areas within the Black Hills for the years 2000 to 2007, was 15% below the average annual 30 year time period between 1971-2000 for this area. In comparison, the table shows that during the past 4 years, there has been a 15% increase in average annual precipitation compared to the 1971 to 2000 time period. The increase in average rainfall during this recent 4 year period, has increased the vegetation growth activity experienced within the Company's service territory. Black Hills Power has calculated that it has 1,451 miles of 230kV, 69kV, and distribution line miles of exposure to areas within the Black Hills National Forest that could be impacted by the Mt. Pine Beetle.

The increased exposure caused by the Mt. Pine Beetle infestation also presents an increased exposure to vegetation impacts from outside the Company's ROW.

Q. DOES BLACK HILLS HAVE PERMISSION TO ADDRESS ISSUES SUCH AS THOSE CAUSED BY THE MT. PINE BEETLE FOR THOSE TREES THAT ARE OUTSIDE OF ESTABLISHED ROW?

A. Yes, in some instances. Black Hills Power has authorization to cut identifiable Mt. Pine Beetle infested trees on National Forest System land that are within 100 feet of either side of the Company's existing ROW. Any issues associated with trees on private property, outside of the Company's existing ROW, will be addressed on a case by case basis with the private landowner.

Q. DOES BLACK HILLS POWER TRACK ANY VEGETATION OUTAGE INFORMATION?

A. Yes. Exhibit MJF - 3 is a table that provides a summary of the number of tree-caused outages that have been documented throughout the Black Hills Power system by trees either inside or outside of the ROW during the time period from 2007-2011.

During this time period, Black Hills experienced a total of 482 tree-caused outages, which impacted 31,961 customers for a total of 5,593,381 customer outage minutes. Approximately 20% of these outages were caused by vegetation within the ROW and the balance of 80% were caused by vegetation from outside of the ROW.

Q. WHAT IS MEANT BY CYCLE TRIMMING AND WHAT ARE THE BENEFITS OF MAINTAINING AN ESTABLISHED TRIM CYCLE?

A. Cycle trimming refers to establishing a desirable time period between when a respective line segment is trimmed on a routine basis. Exhibit MJF – 4 titled Tree Growth provides an example of an area that has not been part of a normal trim cycle and is labeled "Off-Cycle". The corresponding pictures depict what the area would like after it has been properly trimmed and then shows the potential regrowth of the same area during the next 4 year time period. Under a normal trim cycle this area would be trimmed again after the last year of the 4 year trim cycle.

There are a number of benefits associated with maintaining a normal vegetation trimming cycle. These include increased system reliability with fewer outages caused by vegetation and various weather conditions, increased efficiencies with normal routine maintenance causing less inefficient hot spotting clearing, easier to patrol right-of-ways, and fewer outages during major weather events. All of these activities help Black Hills Power to improve our ability to provide safe, reliable, and economical service to our customers.

Q. IS BLACK HILLS POWER PROPOSING ANY INCREASES IN ITS OPERATING AND MAINTENANCE EXPENDITURES ASSOCIATED WITH ITS VEGETATION MANAGEMENT PROGRAM?

A. The Company's vegetation management budget totaled approximately $2 Million in 2012 for the 230 kV, 69kV, and distribution infrastructure. Approximately $1.6 Million of this amount was associated with operating and maintaining, on an annual basis, approximately 180 to 220 miles of distribution facilities, with the balance of $450,000 associated with maintaining the 69 kV & 230 kV transmission facilities.

In order for Black Hills Power to achieve a four to five year trim cycle, as defined within the Company's vegetation management program for the Company's distribution network, the Company has budgeted for 2013 an additional increase of $940,000 in the Company's annual operating expense, which brings the total for distribution vegetation management to approximately $2.6 Million.

Additional information on vegetation management costs are set forth in the testimony of Christopher J. Kilpatrick.

VI. INCREASED COSTS RELATED TO INCREASED FEDERAL REGULATION

Q. HAVE THE COMPANY'S COST TO SERVE CUSTOMERS INCREASED AS A RESULT OF INCREASED FEDERAL REGULATION?

A. Yes. As it pertains to the electric transmission system, the Company has experienced increases in costs in order to comply with federal reliability regulations imposed by FERC and enforced by NERC.

Q. PLEASE DESCRIBE WHY NERC RELIABILITY COMPLIANCE COSTS HAVE INCREASED IN RECENT YEARS.

A. In response to an August 14, 2003 east coast blackout affecting more than 50 million electric customers, Congress passed the Energy Policy Act of 2005 ("EPAct 2005") granting FERC increased authority over electric grid reliability, and ultimately replacing voluntary reliability protocols established by NERC in 1968 with mandatory compliance requirements. After conducting rulemaking proceedings, FERC approved 83 initial mandatory electric reliability standards that became enforceable by NERC in June of 2007.

Q. HAS THE SCOPE OF THE COMPANY'S OBLIGATIONS RELATED TO NERC COMPLIANCE CONTINUED TO INCREASE SINCE 2007?

A. Yes. Since June of 2007 NERC has continued to adopt new standards and modify existing standards, under the oversight of FERC. For example, eight new cyber-security or Critical Infrastructure Protection ("CIP") standards became enforceable in 2008. The CIP standards required mandatory physical and information-system security measures for assets deemed critical to the bulk electric system. The CIP standards, along with other NERC requirements, are subject to continuous revision by FERC; version two of the CIP standards became effective in April of 2010, with the current version (version three) effective in October in 2010. Version four of the CIP standards was approved in April of 2012, and will become effective in April of 2014. The expansion of these requirements is ongoing, as version five of the CIP standards was approved by the NERC Board of Trustees in November 2012, and is pending FERC approval. If approved by FERC, version five is expected to become effective in July of 2015.

Q. PLEASE DESCRIBE SOME OF THE COMPANY'S EFFORTS TO MEET THESE NERC COMPLIANCE REQUIREMENTS.

A. The Company is currently responsible for compliance with approximately 1,100 specific NERC requirements as set forth and defined through more than 100 mandatory NERC standards. The NERC standards and requirements are rigid and specialized. Numerous reviews and tests are required to be performed under strict calendar deadlines, and compliance also requires the monitoring of highly sophisticated systems by well-trained and well-informed employees. Not only must the Company comply with these requirements, the Company must be able to regularly and comprehensively demonstrate its compliance through external regulatory audits, self-certifications, and other compliance reviews. The Company operates under a Code of Business Conduct that requires it to comply with all federal and state statutes and regulations, including NERC standards. In addition, non-compliance can lead to significant financial penalties. The Company has undertaken to fully comply with all mandatory NERC standards, just as the Company complies, for example, with Sarbanes-Oxley financial reporting requirements, and Commission rules.

Q. DO THESE COMPLIANCE EFFORTS IMPOSE COSTS?

A. Yes. Compliance with NERC standards has required the company to add personnel, draft or upgrade policies and procedures, implement, update or expand controls and processes, add or develop new information systems in order to demonstrate compliance, and expand employee training.

VII. ADVANCED METERING INFRASTRUCTURE (AMI METERING)

Q. PLEASE PROVIDE AN EXPLANATION OF THE BLACK HILLS POWER AMI METERING SYSTEM?

A. Black Hills Power has begun a long range project designed to use the latest technology available to continue to provide the Company's customers with safe, reliable electricity at a reasonable cost. One of the ground breaking initiatives associated with this long range vision was the installation of an AMI Metering system that utilized new electric smart meters designed to increase efficiency by using wireless technology to automatically send customer usage information directly from the customers meter to Black Hills Power's computer systems. The installation of these new meters provides a more efficient, accurate way to read meters; increases customer convenience; reduces the need for service personnel to access customers' electric meters on a regular basis; and allows for more frequent readings, resulting in a more accurate bill.

In addition to providing more accurate billing information, the installation of these "smart" meters at each of the Company's customer service centers will allow Black Hills Power to offer customers options that were not available to them through the use of the old electric mechanical meters.

Q. CAN YOU PROVIDE A BRIEF OVERVIEW OF THE "SMART" METERING TECHNOLOGY THAT BLACK HILLS POWER INSTALLED ASSOCIATED WITH THE AMI METERING?

A. The "smart" technology utilized for this project consists of residential and commercial smart meters located at all of the Company's customer service points, which will communicate meter data to multiple collection points (Gateways) strategically located throughout the Black Hills Power service territory. These Gateways communicate the meter data information to the AMI application server via a secure communication data network.

The communication between the "smart" meters and the Gateways operates as a self configuring 900 Mhz wireless "Mesh" technology allowing the system maximum flexibility to reconfigure communication paths dynamically as changes occur in the field. Multiple Gateways have been strategically located throughout the Black Hills Power service area to allow for maximum system redundancy and providing maximum system reliability.

The AMI data collection server is located in a centralized secure data center, with a redundant back-up server located in a back-up data center. Energy usage and meter operational integrity type data is collected, communicated and stored by the AMI system numerous times each day on a near real time basis.

Q. IN ADDITION TO ENERGY USAGE INFORMATION, WHAT OTHER TYPE OF INFORMATION IS COLLECTED BY THESE AMI "SMART" METERS?

A. In addition to providing the typical energy billing type usage information, these meters have the capability to provide and report information associated with a fifteen (15) minute interval usage data, detection of voltage present at the meter, meter tampering detection, remote turn on/off capabilities on select meters, and overall operational health of the meter itself.

Q. WHAT BENEFITS DOES BLACK HILLS POWER EXPECT FROM THE INSTALLATION OF THIS AMI "SMART" METER TECHNOLOGY?

A. The Company's operational costs have decreased because of the automated report meter reading capabilities. In addition, the non–usage type metering information provided by these "smart" meters will assist Black Hills Power in its electrical distribution operations such as power outage indication to the individual customer level, power quality, system reliability and meter tamper/theft detection. This information will also be utilized in the Company's distribution planning activities as it continues to plan, design, construction, and operate a more efficient, reliable electrical distribution network resulting in improved power quality and greater customer service.

Another advantage these “smart” type meters will provide relates to outage restoration. Each of these smart meters have the capability of communicating with the Company’s Outage Management System and therefore providing the Company’s Customer Service/Reliability Center with indications of an outage at a particular location. Therefore the Company will be able to notify customers of outage restoration efforts and it will assist the Company in directing the Company’s service repair crews in the field to the most likely failed piece of equipment.

Along with the installation of the AMI meters, Black Hills Power is also installing a Meter Data Management System (MDMS). The MDMS is a software application that will provide Black Hills Power with an effective way to manage, process, and distribute meter usage information collected by the Company’s AMI system. The MDMS system will enable the Company’s customers to learn more about their energy usage as the system will have the capability of collecting detailed usage information in the form of 15 minute interval energy usage data that can be provided to customers through a web based online application.

Q. WHAT IS THE CURRENT STATUS OF AMI METERING PROJECT?

A. Black Hills Power originally considered the need and justification for this project back in early 2009. Also in 2009, the Department of Energy, announced their Smart Grid Investment Grant (SGIS) program as part of the

American Recovery and Reinvestment Act (ARRA). In August of 2009, Black Hills Power submitted an application to the DOE under the SGIG program that outlined a detailed project plan for the installation of AMI "smart" meters under Phase 1 of the project, and upon completion of the AMI meters in the field, to move on to the Phase 2 with the completion of the Meter Data Management System. As provided for under the DOE SGIG grant program, the application also identified the estimated total project costs along with the fifty percent funding estimate of those project costs that were deemed to meet the qualifications and requirements as defined under the ARRA program. In April 2010, Black Hills was notified by the DOE that the AMI/MDMS project was accepted by the DOE as a viable project. Black Hills Power and the DOE reached an agreement on this project in April 2010, at which time Black Hills Power kicked off the initial phase of the project – the design, procurement, and installation of approximately 69,000 electric meters throughout the Company's service territory. The installation of these meters was completed in late 2011, which then commenced the next phase of the project – the design, procurement, and installation of the MDMS software application. The MDMS software application is scheduled for completion and full implementation by the end of 2012. The projected total project costs of the AMI/MDMS installation through 2012 is $10,470,606. Fifty (50%) percent of this cost has been reimbursed to Black Hills Power by the DOE as part of the SGIG grant program. The remaining fifty (50%) project cost of $5,235,303 is included in the capital assets associated with this rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.