Black Hills Corporation
Kyle D. White
Vice President Regulatory Affairs
kyle.white@blackhillscorp.com

PO Box 1400
Rapid City, SD 57709-1400
P: 605.721.2313
F: 605.721.2568

September 30,2013

Mr. Chris Petrie
Chief Counsel
Wyoming Public Service Commission
2515 Warren Avenue, Suite 300
Cheyenne, WY 82002

Subject: Informational filing of Generation Pool Study Report for Black Hills Power, Inc. and Cheyenne, Light, Fuel and Power Company

Dear Mr. Petrie:

Under the terms of the settlement agreement with the Wyoming Office of Consumer Advocate approved by the Commission in Docket No. 20003-123-ET-12 and 20002-84-ET-12 application for a Certificate of Public Convenience and Necessity for the Cheyenne Prairie Generating Station, our utilities with Wyoming customers agreed to assess and prepare a report regarding the possibilities for continuing to optimize joint operations and planning of the two utilities' power supply resources. A little more than a year ago a collaboration was formed to study ways to create additional benefits for customers through increased interaction and cooperation by Black Hills Power, Inc. and Cheyenne Light, Fuel and Power Company in their power supply activities. The parties that actively engaged in this effort included representatives of the Wyoming Office of Consumer Advocate, the staff of the South Dakota Public Utilities Commission and each utilities' largest customers.

Enclosed is the result of the collaborative which details the efforts, assessments and conclusions reached. As is typical for such an effort, there was not always complete consensus regarding all aspects of the report. Therefore, the report should be considered the views of the utilities. We are pleased to state, however, that the report's findings and conclusions are substantially supported by the parties to the collaborative.

We found the effort to be worthwhile and have made or are making changes to our efforts that will provide benefits for customers. We also appreciated the spirit and commitment that our collaborative partners brought to the endeavor. We have a better work product because of their engagement and participation.

The informational filing of this report with you fulfills our obligations under the settlement agreement. If you would like an in-person presentation and discussion of the efforts and findings, please contact me and we can arrange a meeting to accomplish this.

If you have any questions regarding the process, the report or its findings, please feel free to contact me or Lisa Seaman at (605)-721-2278.

Sincerely,

Kyle D. White

Kyle D. White

c: Todd Brink
Lisa Seaman
Parties to the collaboration

Black Hills Power and Cheyenne Light Fuel and Power Generation Pool Study

Volume I - Report

September 30, 2013

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ES.1 Executive Summary

As part of the Order through which the Wyoming Public Service Commission (WPSC) issued a Certificate of Public Convenience and Necessity (CPCN) for the Cheyenne Prairie Generating Station, the WPSC approved the Stipulation and Agreement between Black Hills Power (BHP); Cheyenne Light, Fuel and Power (Cheyenne Light); and the Wyoming Office of Consumer Advocate (OCA). This Stipulation and Agreement provided, among other provisions, that BHP and Cheyenne Light would conduct a Generation Pool Study.

The generation pool study was conducted and, in accordance with the Stipulation and Agreement, a collaboration was formed between BHP, Cheyenne Light and the OCA. In addition, the Staff of the South Dakota Public Utilities Commission and consultants representing a group of interveners in Black Hills Power's rate case, Black Hills Industrial Interveners, participated in this collaboration. The stakeholders oversaw the conduct of the study commenting on the process, the analysis conducted, and drafts of this report.

At the outset of this generation pool study effort, the collaborative believed that the study would evaluate three generation pool alternatives:

1) Continue current operation but with the addition of a planning reserve capacity agreement and a joint planning process
2) Create a generation holding company that would own the BHP and Cheyenne Light generation assets with allocation of the cost of generation to each of the utilities
3) Merging BHP and Cheyenne Light into one utility

As the effort progressed, however, it was decided to examine only the first two alternatives. In addition, the collaborative decided that it made sense to initially examine the existing system costs for each of the two utilities. Therefore, a system cost analysis was conducted comparing the projected system costs, on a dollars per MWh basis, expected to be incurred for the Cheyenne Light and BHP customers for the next five years on a standalone basis.

The system cost analysis showed that the costs for BHP were lower in all years that were analyzed than Cheyenne Light. This analysis led to the following conclusions:

- The system costs for Cheyenne Light and BHP remain significantly different in the early years of the planning period.
- BHP's total system cost is lower than Cheyenne Light's primarily due to the vintage of its resources.
- If a generation pool were developed, historical power supply cost differences will need to be addressed to ensure future pricing equity.

- Over just the first five years, equalizing production costs between BHP and Cheyenne Light would result in higher costs to BHP of more than $50 million.

The first generation pool alternative examined reflects the current independent operation of BHP and Cheyenne Light, but with the addition of a planning reserve capacity agreement and joint resource planning process. Under current independent operation, there are four agreements between the two utilities. These include the Generation Dispatch and Energy Management Agreement (GDEMA), the Spinning Reserve Sharing Agreement, the Economy Energy Service Agreement, and the Shared Facilities Agreement. The benefits of the Economy Energy Agreement were examined in the course of evaluating current operation. In addition, BHP and Cheyenne Light have contemplated the addition of a planning reserve capacity agreement that would allow BHP and Cheyenne Light to share firm capacity for planning reserves and conducting joint resource planning to allow the entities to take advantage of economies of scale, to construct larger units than might otherwise be the case relative to standalone planning and other potential benefits.

The anticipated savings from the planning reserve capacity agreement and the joint planning process over the 20-year planning horizon for the base load scenario is $51.40 million. The anticipated savings due to the economy energy service agreement over the 20-year planning horizon for the base load scenario is $16.19 million. The planning reserve capacity agreement and joint planning process benefits include:

- Providing an economic option for meeting planning reserve requirements rather than purchasing firm energy for short-term contingencies on the market at a higher price.
- The selling party benefits by receiving a capacity payment.
- The procuring party can purchase economy energy to meet its energy needs.
- The agreement does not obligate utilities to sell capacity to each other.
- The agreement expands both parties' ability to acquire needed capacity.
- Future resource acquisitions may "fit" the resource need because resources are sized for a larger system.

The primary incremental potential benefit of creating a generation holding company is to combine the loads of BHP and Cheyenne Light into one forecast, thus creating potential for diversity benefits in addition to the benefits of reserve sharing and joint planning. In addition to an examination of the benefits of a generation holding company, the issues related to its creation were examined. Issues include numerous financial, legal, and regulatory steps which could impose substantial additional costs and uncertainty as to when such a process might be completed. The projected savings for a combined system (combined dispatch and joint planning) over the 20-year planning period for the base load scenario is $105.89 million.

The analysis shows that existing operation with the addition of a planning reserve capacity agreement and a joint planning process captures a significant portion of the possible savings that would be realized through a generation holding company without the legal and financial obstacles that would need to be overcome in order to form that generation pool (see Table ES-1).

Table ES-1
Base Load Scenario – Combined System Savings Versus Savings from Agreements (PVRR – $ millions)

	Base Load Scenario	Source of Number
Combined System Savings	$105.89	Table 3-10
Savings from Planning Reserve Capacity Agreement and Joint Planning Process	$51.40	Table 3-4
Savings from Economy Energy Service Agreement	$16.19	Table 3-9
Savings not realized from pooling	$38.3 or less than $2 million per year. About 1% of the total PVRR over the 20-year period.	

1.0 Introduction

1.1 Generation Pool Study Background

Black Hills Corporation (BHC) acquired Cheyenne Light, Fuel and Power (Cheyenne Light) in 2005 and since that time Cheyenne Light and Black Hills Power (BHP) have entered into contracts that allow the two utilities to benefit from efficiencies gained through the sharing of spinning reserves, economy energy purchases, power plant operations, and generation dispatch and power marketing. In addition, many common operational functions have been centralized allowing the utilities to achieve further efficiencies and cost savings.

Resource planning for BHP and Cheyenne Light has been conducted jointly as well as independent of one another. Most recently, in 2011, BHP and Cheyenne Light conducted independent resource plans that resulted in the utilities jointly applying for and receiving a Certificate of Public Convenience and Necessity (CPCN) from the Wyoming Public Service Commission (WPSC) to construct the jointly-owned Cheyenne Prairie Generating Station in Cheyenne, Wyoming. As part of the Order through which the WPSC issued a CPCN for the Cheyenne Prairie Generating Station, the WPSC approved the Stipulation and Agreement between BHP, Cheyenne Light and the Office of Consumer Advocate (OCA). This Stipulation and Agreement provided, among other provisions, that BHP and Cheyenne Light conduct a Generation Pool Study. The Stipulation and Agreement reads in part:

> *The Parties agree that with the construction of the Cheyenne Prairie Generating Station it is an appropriate time to seriously evaluate the potential costs and benefits of a combined generation pool for the Utilities. The potential benefits of such a pool arrangement could include among other things, more efficient and comprehensive resource planning and acquisition and the potential for more efficient and transparent operation of the combined system. Therefore, a collaboration will be formed between Black Hills Power, Cheyenne Light, the OCA and the Staff of the South Dakota Public Utilities Commission… for the purpose of thoughtfully evaluating the creation of a generation pool . . . the parties to the collaborative will begin to jointly develop the study scope.* [the collaborative will] *meet thereafter as necessary to complete the study. . . The Applicant shall be principally responsible for conducting the study with periodic review and comment by the other collaborators.*
>
> *Possible considerations for the study include:*
> - *Existing power supply costs*
> - *Expected power supply costs*
> - *Off-system sales opportunities*
> - *Transmission requirements*

- *Load characteristics*
- *Planning and operating reserves*
- *State and federal regulatory considerations and restrictions*
- *Structure of generation pool and related agreements*
- *Timing of implementation (if appropriate)*
- *Balancing purchases and sales*
- *Increased market access*
- *Plant dispatch*
- *Plant fuel requirements*
- *Other considerations as necessary*

. . .The parties to the collaborative will endeavor to reach agreements regarding the development of a power pool or other mechanisms to promote the efficient planning and operation of the Companies' electric generation resources and will identify, in the report, any agreements reached. . . .

The stipulation requires that the study be completed by September 30, 2013, and that the members of the collaborative be able to review and comment on the study report prior to final publication of the report. The final report will be provided to each utility's respective state regulatory bodies on an informational basis. BHP and Cheyenne Light agreed to spend up to $100,000 for outside expertise such as consulting or legal support costs at shareholder expense.

1.2 Description of BHP and Cheyenne Light

1.2.1 Black Hills Power

Black Hills Power (BHP) serves approximately 68,500 customers in 25 communities located in Western South Dakota, Northern Wyoming, and Southeastern Montana. In 2012, BHP sold more than 3,311 GWh of electricity through retail sales, contract wholesale sales and off-system wholesale sales. BHP's 2012 summer system peak was 449 MW and its winter peak in 2012 was 362 MW. BHP currently meets electric demand through purchases from the open market and from the following power purchase agreements (PPA) and generation assets:

- PacifiCorp PPA expiring in 2023, which provides for the purchase of 50 MW of coal-fired baseload power;
- Cheyenne Light's and BHP's Generation Dispatch Agreement that requires BHP to purchase all of Cheyenne Light's excess energy (Cheyenne Put);
- Happy Jack and Silver Sage Wind Farm PPAs expiring in 2028 and 2029, respectively, for an accredited capacity of 3.5 MW;
- Four coal-fired power plants with a total net capacity of 232 MW (the Neil Simpson 1 coal-fired plant will be retired in March 2014);
- One diesel station with a net capacity of 10 MW;

- Three natural gas-fired combustion turbine stations with a combined net capacity of 160 MW.

BHP's power delivery system consists of approximately 592 miles of transmission lines (greater than 69 kV) and 3,059 miles of distribution lines (69 kV or lower). BHP also owns 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids. This transmission tie provides transmission access to both the Western Electricity Coordinating Council (WECC) region in the West and the Mid-Continent Area Power Pool (MAPP) region in the East.

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

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

- In conjunction with MDU's April 2009 purchase of a 25% ownership interest in Wygen III, an agreement to supply 74 MW of capacity and energy through 2016 was modified. Sales to MDU have been integrated into BHP's control area and are considered part of its firm native load. Capacity from the Wygen III unit is deemed to supply a portion of the required 74 MW. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from BHP's other generation facilities or from system purchases with reimbursement of costs by MDU;
- BHP's agreement with the City of Gillette is to dispatch the City's 23% of Wygen III's net generating capacity for the life of the plant. Upon the City of Gillette's July 2010 purchase of a 23% ownership interest in Wygen III, a seven-year PPA with the City of Gillette that went into effect in April 2010, was terminated. The City of Gillette's 23 MW of Wygen III capacity has been integrated into BHP's control area and is considered part of its firm native load. During periods of reduced production at Wygen III, or during periods when Wygen III is off line, BHP will provide the City of Gillette with its first 23 MW from BHP's other generation facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, BHP will also provide the City of Gillette its operating component of spinning reserves;
- BHP has an agreement to supply 20 MW of energy and capacity to the Municipal Energy Agency of Nebraska (MEAN). This contract is unit-contingent based on the availability of the Neil Simpson II and Wygen III plants, with capacity purchases decreasing to 15 MW in 2018, 12 MW in 2020 and 10 MW in 2022. This contract expires in 2023

- BHP's five-year PPA with MEAN which commenced in May 2010 whereby MEAN will purchase 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III.

1.2.2 Cheyenne Light, Fuel and Power

Cheyenne Light serves approximately 40,000 electric customers and 35,000 natural gas customers in Cheyenne and a large portion of Laramie County, Wyoming, including natural gas service to Pine Bluffs, Burns, and Carpenter in eastern Laramie County, Wyoming. Cheyenne Light's 2012 system summer peak was 187 MW and its winter peak in 2012 was 174 MW.

Cheyenne Light currently meets electric demand through purchases from the open market and from the following PPAs and generation assets:

- One coal-fired power plant with a total net capacity of 90 MW;
- A PPA with Black Hills Wyoming for 40 MW from CT2 which expires in August 2014;
- Two PPAs with Duke Energy for the energy from the Happy Jack and Silver Sage wind facilities in Cheyenne, Wyoming. These PPAs expire in 2028 and 2029, respectively;
- A PPA with BH Wyoming for 60 MW from Wygen I which expires in 2022; this PPA includes an option for Cheyenne Light to purchase Black Hills' Wyoming's ownership share of the Wygen I facility.

In addition, Cheyenne Light has entered into agreements with Basin Electric for the purchase and sale of 40 MW of capacity and energy. Cheyenne Light purchases 40 MW of capacity and energy from Basin Electric that is delivered at the Ault Substation and sells 40 MW of capacity and energy to Basin Electric that is delivered to one of the substations on the Black Hills Basin Electric (BHBE) Transmission System. These agreements expire on September 30, 2014.

Cheyenne Light's power delivery system consists of approximately 25 miles of transmission lines (greater than 69 kV) and 1,229 miles of distribution lines (69 kV or lower).

1.3 Stakeholder Meetings and Education

Per the Stipulation and Agreement, a collaborative was established with the Wyoming OCA, the Staff of the South Dakota Public Utilities Commission (SDPUC), BHP, Cheyenne Light, and other parties whose interests could be affected by the outcome of the generation pool study. The first stakeholder meeting was held in September 2012. At this meeting, BHP and Cheyenne Light provided information related to current operation of both utility's generation assets and stakeholders discussed the scope of the generation pool study. Subsequent meetings were held throughout 2012 and 2013 to further inform stakeholders about transmission, environmental regulations and generation dispatch operations. Notes from stakeholder meetings can be found in Volume III along with copies of the presentations made to the stakeholders at those meetings. The stakeholders jointly developed the study scope, reviewed the analysis and results, and reviewed the report prior to its completion.

At the first stakeholder meeting, the collaborative agreed upon the objective of the generation pool study: "To assess costs/benefits of utility power supply integration for an uncertain future." The parties also agreed that production cost modeling would identify if pooling the generation resources of the two utilities would provide cost savings. At subsequent meetings, the stakeholders discussed and agreed on a modeling approach and associated assumptions. The assumptions are contained in Volume II.

2.0 Utilities Overview

Since the acquisition of Cheyenne Light by BHC in 2005, various levels of joint operation and resource planning between Cheyenne Light and BHP have occurred. The most recent, in 2011, was the joint application for a CPCN for the Cheyenne Prairie Generating Station.

This chapter provides an overview of the resource planning and operations for each utility and the joint activities that have taken place to date.

2.1 BHP and Cheyenne Light Resource Planning History

On January 21, 2005, BHC closed its purchase of Cheyenne Light from Xcel Energy. An Integrated Resource Plan (IRP) for 2005-2016 was filed with the Wyoming Commission in March 2005 that evaluated Cheyenne Light as a standalone system, BHP as a standalone system, and a BHP/Cheyenne Light combined system. For the BHP/Cheyenne Light combined system, this IRP identified that a coal-fired resource (Wygen II) was required in the 2008 time frame and that a resource would also be required in the 2009-2011 time period. This IRP concluded that combining the systems on an operational (dispatch) and planning basis provided benefits.

Subsequently, in 2007, a joint BHP/Cheyenne Light IRP for 2008-2027 was filed that evaluated the resource requirements of the combined BHP/Cheyenne Light system. A combined system was examined as the 2005 IRP had shown that combined operations and planning provided benefits. This IRP identified the addition of a coal-fired resource (Wygen III) in 2010. No cost or resource allocation between BHP and Cheyenne Light was performed as part of the IRP. The results of this IRP were consistent with the IRP completed in 2005.

During certification and rate case hearings associated with Wygen II and Wygen III, the WPSC and SDPUC expressed concern that combined IRPs had been conducted for the two utilities, but the assets identified in the IRPs were built and owned by a single utility. Thus, in 2011, when BHP and Cheyenne Light each identified a need to conduct IRPs, these IRPs were completed on a standalone basis. The Cheyenne Light IRP was completed first which resulted in Cheyenne Light filing an application for a CPCN for the addition of three combustion turbines (CT). During the process of performing the BHP IRP, it became apparent that a combined cycle unit jointly-owned by BHP and CLFP might best meet the resource needs of the two systems. Therefore, Cheyenne Light withdrew its request for a CPCN for three CTs and filed a joint CPCN with BHP for the installation of a jointly-owned combined cycle and a Cheyenne Light-owned CT (the Cheyenne Prairie Generating Station). A joint resource plan was not completed to support the request for the joint CPCN; however, BHP and Cheyenne Light did complete additional analysis to determine the financial impact on the individual resource plans.

2.2 BHC/BHP/Cheyenne Light Operations Background

Shortly after BHC acquired Cheyenne Light in 2005, a number of operational changes were implemented to increase efficiency and reduce costs for BHP and Cheyenne Light customers. The creation of Black Hills Service Company provides for reduced overhead and shared information systems. Through the service company, departments have been consolidated to provide common services for each of the company's utilities. The consolidated departments include engineering, regulatory/resource planning, human resources, accounting, finance, customer service, and outage management. In addition, common software systems have been put in place for the customer information system, the geographical information system, human resources, outage management, and financial software. Through this effort, redundant systems were eliminated, resulting in seven core systems that are utilized for the majority of the company's employees' and customers' needs.

2.3 Existing Agreements for Operational Cost Savings

Four agreements are currently in place that allow BHP and Cheyenne Light to take advantage of operational cost savings. These include the Generation Dispatch and Energy Management Agreement (GDEMA), the Spinning Reserve Sharing Agreement, the Economy Energy Service Agreement, and the Shared Facilities Agreement.

2.3.1 Generation Dispatch and Energy Management Agreement (GDEMA).

The parties to this agreement are BHP and Cheyenne Light. The agreement allows BHP to utilize its capabilities, systems, and staff to manage the dispatch of BHP's and Cheyenne Light's generating facilities and other power resources on a system-wide least cost basis taking into consideration the cost and reliability of resources and transmission services. Under the agreement, BHP manages the BHP and Cheyenne Light systems in a coordinated manner to allow BHP and Cheyenne Light to serve their customers using the least cost mix of both parties' energy resources. These resources are comprised of each party's generating facilities, long-term capacity and energy purchases, and short-term economy energy purchases regardless of ownership or control of those resources by BHP or Cheyenne Light. The GDEMA allows Cheyenne Light to rely on BHP's generation dispatch and energy management capabilities and experienced personnel on an at-cost basis, freeing Cheyenne Light from the need to develop duplicative capabilities.

BHP and Cheyenne Light each own generating facilities which are located in western South Dakota and northeastern Wyoming; however, the Cheyenne Light service area is not directly interconnected to those generating facilities. The GDEMA includes a provision that allows BHP to arrange transmission service on the Western Area Power Administration, Colorado-Missouri Region (WACM) system on behalf of itself and Cheyenne Light. The agreement also includes the provision that BHP buys surplus energy from Cheyenne Light to facilitate service to customers on a least-cost basis.

2.3.2 Spinning Reserve Sharing Agreement

The three parties to this agreement are BHP, Cheyenne Light, and Black Hills Colorado Electric. This agreement allows any of the three parties to rely on another of the parties' resources when a party needs to procure spinning reserves but is unable to procure spinning reserves from an unaffiliated third-party supplier. Under the terms of this agreement, a party that supplies spinning reserves may recover its actual cost of providing the spinning reserve service.

2.3.3 Economy Energy Service Agreement

The three parties to this agreement are BHP, Cheyenne Light, and Black Hills Colorado Electric. This agreement allows the three parties to voluntarily sell and buy economy energy services among themselves. Under the terms of this agreement, the purchasing party may only purchase Economy Energy Service from another party to this agreement when the purchaser is unable to procure reliable energy from an unaffiliated supplier at a price lower than the price for the Economy Energy Service. In addition, the agreement only allows the supplying party to make energy available to another party if the sale does not displace an opportunity to sell that energy at a higher price.

2.3.4 Shared Facilities Agreement

This agreement is between BHP and Cheyenne Light. The agreement allows that certain capital assets located at the Neil Simpson Complex in Gillette, Wyoming and owned by one of the parties may be used to support the operations of one or more of the plants not directly owned by the party owning the shared capital asset. The parties pay a fee as consideration for the benefit from their use of the shared capital assets plus a share of the operating and maintenance and expenses of the shared capital assets.

2.4 Operational Efficiencies Already Implemented

BHP and Cheyenne Light both own generation facilities at the Gillette Energy Complex located near Gillette, Wyoming. The utilities, through existing agreements, share land ownership, infrastructure, facilities and staff for the operation of their generation facilities at the Gillette Energy Complex. In addition, BHP and Cheyenne Light are constructing the jointly-owned natural gas-fired generation in Cheyenne, Wyoming (the Cheyenne Prairie Generating Station) and will establish similar agreements to share common facilities, infrastructure and staff at this plant.

3.0 Generation Pool Alternatives

At the outset of this generation pool study effort, the collaborative believed that the study would evaluate three generation pool alternatives:

1. Continue current operation but with the addition of a planning reserve capacity agreement and a joint planning agreement
2. Create a generation holding company that would own the BHP and Cheyenne Light generation assets with allocation of the cost of generation to each of the utilities
3. Merging BHP and Cheyenne Light into one utility.

As the effort progressed, however, it was decided to examine only two of the alternatives:

1) Current operation with the addition of a Planning Reserve Capacity Agreement and joint resource planning, and
2) A generation holding company with combined dispatch and joint planning.

The collaborative decided that for the purposes of this generation pool study and report, the third alternative, merging BHP and Cheyenne Light into one utility, would be limited to identifying all of the efforts and issues associated with this option. Those efforts and issues are summarized in Appendix A.

As the study progressed, the collaborative also decided that it made sense to initially examine the existing system costs for each of the two utilities. A system cost analysis was conducted comparing the projected system costs expected to be incurred for Cheyenne Light and BHP for the next five years on a standalone basis. This analysis is described first, followed by a description of the analysis that was conducted to quantify the potential benefits of current operation with the addition of agreements, and then the potential benefits and issues related to the formation of a generation holding company.

3.1 System Cost Analysis

System costs were calculated for Cheyenne Light and BHP for the years 2013 through 2017 based on BHC's five-year strategic plan assumptions. Values were determined on a $/MWh basis and included owned, contracted and short-term purchased resources. Key assumptions include Cheyenne Light's purchase of Wygen I in October 2014 and the retirement of two of BHP's coal-fired units, Ben French Steam unit in 2012 and Neil Simpson I in March of 2014.

Table 3-1
System Cost Analysis ($/MWh)

Year	BHP	Cheyenne Light	Average System
2013	44.91	51.74	47.33
2014	48.92	60.00	52.96
2015	53.78	68.01	59.18
2016	55.96	69.78	61.22
2017	55.50	68.20	60.34

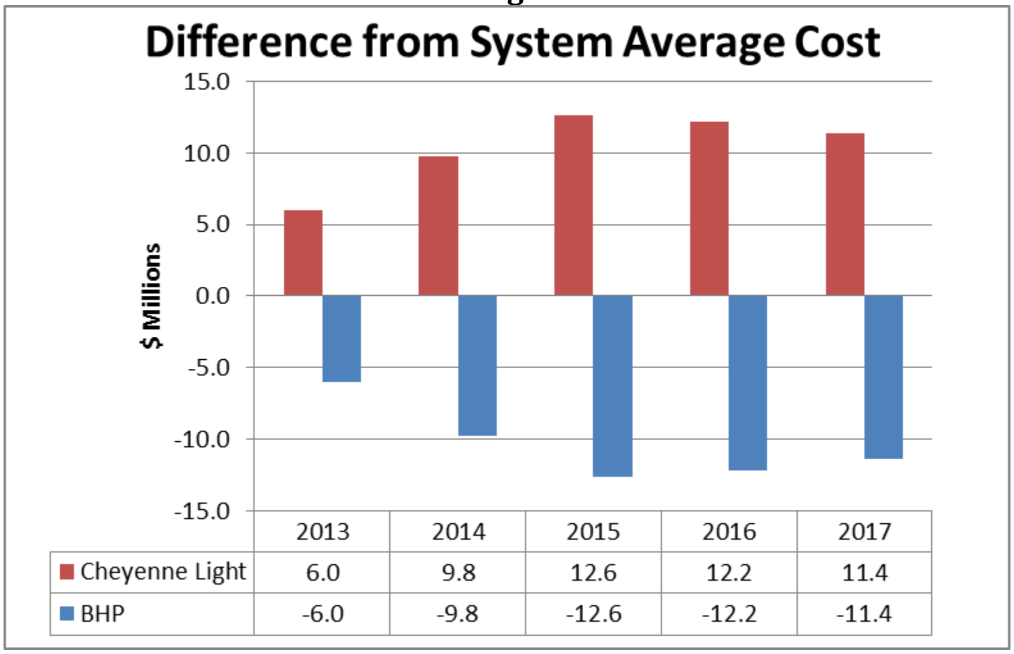
As shown in Table 3-1, the system costs for BHP are lower than the system costs for Cheyenne Light in all years that were analyzed. The spread between the system costs is $6.83/MWh in 2013 and increases in 2014 and 2015. In 2014, the Cheyenne Prairie Generating Station (with ownership shares for each of Cheyenne Light and BHP) will begin commercial operation. In 2015, the system costs increase for both companies, and the difference also increases to over $14/MWh. In 2016 and 2017, the spread in the system costs begins to decline. Although the system cost analysis did not extend for the entire 20-year planning period used for the generation pool study, the short-term analysis shows a continuing system cost disparity between the two utilities.

The conclusions of the system cost analysis include:

- The system costs for Cheyenne Light and BHP remain significantly different in the early years of the planning period.
- BHP's total system cost is lower than Cheyenne Light's primarily due to the vintage of its resources.
- If a generation pool were developed, historical power supply cost differences will need to be addressed to ensure future pricing equity.
- Over just the first five years, equalizing production costs between BHP and Cheyenne Light would result in higher costs to BHP of more than $50 million.

Figure 3-1 shows the difference in cost between BHP and Cheyenne Light and the average system cost for 2013-2017. This figure shows that equalizing production costs in 2013 would raise costs to BHP customers by $6 million, while lowering costs to Cheyenne Light customers by the same amount.

Figure 3-1



3.2 Current Operation with Addition of Planning Reserve Capacity Agreement and Joint Resource Planning

The first generation pool alternative to be examined reflects the current independent operation of both BHP and Cheyenne Light, but with the addition of a planning reserve capacity agreement and a joint resource planning process. Under current independent operation, there is an existing Economy Energy Service Agreement between the two utilities. The potential benefits of this agreement were also examined in the course of evaluating current operation.

3.2.1 Planning Reserve Capacity Agreement

BHP and Cheyenne Light each have an obligation to maintain planning reserves and on occasion have a need to procure this planning reserve capacity from the market to fulfill capacity requirements. A planning reserve capacity agreement would allow BHP and Cheyenne Light to share firm capacity for planning reserves. Under this proposed agreement, one of the parties would be able to purchase planning reserve capacity from the other party when the procuring party cannot satisfy its entire reserve obligation using its own resources due to a short-term contingency. A short-term contingency, as defined in the proposed agreement, means an event or condition causing a procuring party to require additional planning reserve capacity for a period not to exceed 30 days. In addition, the agreement would be system contingent. This means that if the supplying party needed to recall its capacity to satisfy its own system needs, the procuring party would need to find an alternative source of planning reserve capacity.

The terms of this agreement are similar to the agreement that BHP has with the City of Gillette for planning reserve services. The price structure stipulates that the selling party will recover its cost of providing the planning reserve service taking into account both the firm capacity itself and associated energy. The capacity charge would take into account fixed costs including insurance, interest expenses, return on equity, property taxes, and federal income taxes. The variable and fuel costs would be recovered based on actual costs incurred to provide the planning reserve service.

As currently drafted, the agreement would contain no requirement for evaluating other sources (third-party) of capacity prior to purchasing capacity from the other party. In addition, neither party would be obligated to provide planning reserve capacity to another party

The intent of this agreement is to allow BHP and Cheyenne Light to provide a beneficial service to the other that will allow them to economically satisfy their planning reserve requirements and help maintain system reliability. This type of agreement particularly makes sense within the market that BHP and Cheyenne Light operate. Capacity markets have not developed in the West, as has been the case in many of the North American Electric Reliability Corporation (NERC) regions in the Eastern Interconnection. In the West, transactions are usually energy transactions such as 6 x 16 sales. In addition, the agreement would provide the benefit to both BHP and Cheyenne Light that procuring the planning capacity through the agreement then allows the purchaser to buy economy energy in the market to meet energy needs.

The primary issues to be examined with a planning reserve capacity agreement are financial and legal. With the addition of a planning reserve capacity agreement, off-system sales opportunities might be reduced, reducing the benefit to customers that are gained through those off-system sales opportunities. Outside legal review is required and an application may need to be filed with the FERC for approval of the Planning Reserve Capacity Agreement. State regulatory filings may also be required.

3.2.1.1 Planning Reserve Capacity Agreement Analysis

The intent of this agreement is to allow BHP and Cheyenne Light to provide a beneficial service to the other that will allow them to economically satisfy their planning reserve requirements and help maintain system reliability. To determine the potential benefits associated with the planning reserve capacity agreement, two scenarios were examined:

1. Capacity shortfall due to load growth and unit retirement (Table 3-2)
2. Capacity shortfall due to short-term unit outage (Table 3-3)

For both scenarios, the following assumptions apply:

- The cost structure includes two cost components: capacity and energy. The capacity charge used in the analysis is the same capacity charge as is found in the planning reserve capacity agreement already in place with the City of Gillette. The energy charge is 75% of the forward market price. An assumption is made that any needed energy would be purchased in order to avoid calling on the capacity.
- The forward market pricing used is the Palo Verde Price. The values are based on the Argus U.S. Electricity Forecast and prices are from the June 10, 2013 forward market information.
- The capacity requirements occur for 6 days per week, 8 hours per day.

The examples shown in Table 3-2[1] and 3-3 are demonstrative of the benefits and costs that would be expected through the implementation of the planning reserve capacity agreement.

[1] This example shows approximately $1.2 million in savings primarily based on the assumption that in 2014 Cheyenne Light will have capacity deficits in several months due to load forecast assumptions and expiration of a purchase power agreement. This example does not necessarily represent expected annual savings.

Table 3-2

Planning Reserve Capacity Analysis – Load Growth and Unit Retirement (2014)

Item	Jan	Feb	Mar	Apr	May	Sep	Oct	Nov	Dec	2014
BHP Capacity Excess/(Deficit) (MW)	39	46	76	88	75	44	134	95	54	
Cheyenne Light Capacity Excess (Deficit) (MW)	(36)	(31)	(21)	(11)	(17)	(66)	23	8	(3)	
Planning Reserve Capacity that can be supplied by BHP (MW)	30	29	21	11	17	44			3	
Cost of Capacity										
Cheyenne Light Capacity Cost paid to BHP ($)	$74,730	$72,239	$52,311	$27,401	$42,347	$109,604	-	-	$7,473	$386,105
Cheyenne Light Energy Cost ($)	$179,820	$154,512	$121,212	$64,865	$104,101	$321,098	-	-	$18,018	$963,636
Total Cost	$254,550	$226,751	$173,523	$92,266	$146,448	$430,702	-	-	$25,491	$1,349,731
Cheyenne Light Cost to Purchase Firm Energy ($/MW)	$479,520	$412,032	$323,2323	$172,973	$277,603	$856,261	-	-	$48,048	$2,569,669
Benefit/(Cost) to Cheyenne Light	**$224,970**	**$185,281**	**$149,709**	**$80,707**	**$131,155**	**$425,559**	**-**	**-**	**$22,557**	**$1,219,938**
Benefit/(Cost) to BHP	**$74,730**	**$72,239**	**$52,311**	**$27,401**	**$42,347**	**$109,604**	**-**	**-**	**$7,472**	**$386,105**

For 2014, as shown in Table 3-2, BHP is expected to have a capacity excess in all months of the year except June, July, and August. That capacity excess ranges from a low of 39 MW to a high of 134 MW. During those same nine months, Cheyenne Light is expected to have a capacity deficit in every month except October and November. The value that is shown on the third line of Table 3-2, the amount of planning reserve capacity that can be supplied by BHP, is the lower of 1) the planning reserve requirement (January and February), 2) the actual deficit (March, April, May, and December), or 3) the amount of BHP capacity excess (September).

Using January as an example, Cheyenne Light pays a capacity cost to BHP ($74,730) and the actual cost of energy ($179,820) which sum to a total cost ($254,550). If Cheyenne Light had purchased these services from a third party, the costs are estimated to have totaled $479,520. Thus, Cheyenne Light received a benefit of $224,970 ($479,520 - $254,550). BHP was compensated at cost for the energy produced and received a benefit for the cost of capacity of $74,730. For the year 2014 as a whole, the estimated benefits for Cheyenne Light for the planning reserve capacity agreement are $1,219,938. BHP's expected benefits for the year total $386,105.

The second example involves a two-day outage in March 2014 of Neil Simpson II, a unit owned by BHP. As shown on Table 3-3, Neil Simpson II is an 80 MW unit and the entire unit is out for maintenance. In March, Cheyenne Light has excess capacity of 45 MW. The capacity charge used in this analysis, $3.35/MWh, equates to the capacity charge in the planning reserve capacity agreement already in place with the City of Gillette. For this example, the capacity charge was reduced to a $/MWh basis because the outage was only for two days. In addition, it was assumed that BHP would only need the capacity for on-peak hours (16 hours).

BHP pays Cheyenne Light $4,824 for capacity and $29,970 for energy for a total cost of $34,794. If that service had been purchased in the market, BHP would have paid $53,280. Thus the benefit to BHP is $18,486 and the benefit to Cheyenne Light is $4,824.

Table 3-3
Planning Reserve Capacity Analysis – Unit Outage

2-Day Unit Outage Example	March 2014
Loss of Neil Simpson II (MW)	-80
Cheyenne Light Excess Capacity (MW)	45
BHP Capacity Cost ($/MW)	
Paid to Cheyenne Light ($) ($3.35/MWh)	$4,824
BHP Energy Cost ($) (Market Price – 10%)	$29,970
Total Cost ($)	$34,794
Cost to Purchase Firm Energy ($)	$53,280
Benefit to BHP ($)	**$18,486**
Benefit to Cheyenne Light ($)	**$4,824**

3.2.2 Joint Resource Planning

At present, there is no draft joint planning agreement. The potential benefits of such an agreement (in conjunction with the other existing agreements and proposed planning reserve capacity agreement) would be to allow the entities to take advantage of economies of scale, to construct larger units than might be the case relative to standalone planning and potentially other benefits. The implementation of joint planning, in conjunction with the planning reserve capacity agreement, would allow for potential benefits in deferring the need for additional capacity by allowing reserves to be shared among the operating units.

South Dakota regulators have previously expressed some preference for a standalone planning process. Joint planning gives rise to concerns regarding the allocation of new capacity between affiliated companies, which has been a source of controversy within the utility industry over the years. Examples where such issues have arisen include the Middle South Utilities (now Entergy) Grand Gulf case[2] and the American Electric Power Rockport case[3]. Further, the PacifiCorp states have struggled with the issue of allocation of resources among their six jurisdictions for decades[4].

Developing a complete Joint Planning Agreement would entail trying to anticipate a wide range of possible issues and circumstances. It would be very unlikely that one could anticipate and resolve all potential problems or issues in advance. For example, a large customer load addition in one utility's service territory may require the completion of a resource plan and acquisition of resources to supply the new

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[2] Grand Gulf dealt with allocation of a nuclear plant between Middle South Utilities operating units in Louisiana, Arkansas, and Mississippi. Grand Gulf was owned by a FERC-regulated subsidiary and sold power under a contract to the operating units. The allocation of power to the states was a highly contentious issue and ended up in the U.S. Supreme Court. *Mississippi Power v. Miss. Ex Rel*. Moore, 487 U.S. 354 (1988) 487 U.S. 354 *Mississippi Power & Light CO. v. Mississippi Ex Rel*. Moore, Attorney General of Mississippi, et al Appeal from the Surpreme Court of Mississippi No. 86-1970.

[3] The Rockport Case had similarities to the Grand Gulf case in that it involved allocation of power sales contract for 15% of output of the Rockport coal plant located in Indiana to Kentucky Power, the AEP operating unit in Kentucky. The Kentucky Public Service Commission disallowed recovery of Rockport costs for KU through a series of orders including Kentucky Public Service Commission Docket Nos. 8721, 9061, 9325 and 9732-B. The Kentucky Commission found it would be less costly for Kentucky Power to purchase power from the AEP Pool, which was its right under the pooling agreement than to buy power from Rockport, thus invoking a disallowance.

[4] The PacifiCorp states have struggled with the issue of allocation of resources among their six jurisdictions. In the case of PacifiCorp, the problem can be traced back to decisions made by Pacific Power & Light (PP&L) and Utah Power & Light (UP&L) at the time of their merger in 1988. The two utilities did not resolve this difficult issue when approval of the merger was being sought in the various states. Rather, they offered to convene a jurisdictional allocation committee with all of the involved states *after* approval of the merger was obtained. Re PacifiCorp, OPUC Docket No. UF 4000, Order No. 88-767 at 5 (July 15, 1988). A major concern of regulators in Oregon and Washington was the impact of the higher cost UP&L system on the lower cost PP&L system. Re PacifiCorp, WUTC Docket No. U-87-1338-AT Second Supplemental Order Approving Merger with Requirements at 14

load. If the other utility continues to grow at a typical rate and does not need additional resources, it should not be required to participate in the resource plan. Consequently, a more productive approach would be to develop a set of principles to guide the joint planning process. Some possible principles are set forth below:

1. Joint resource planning has the potential to provide benefits to both BHP and Cheyenne Light customers, and should be evaluated as part of the IRP process or when a new resource addition is being considered by either utility. The joint resource planning process will identify any benefit of load diversity.
2. Owing to the unique nature of the BHP and Cheyenne Light systems, there may be instances where joint resource planning is not feasible, appropriate, or could fail to result in equitable allocation of costs and benefits of resources among BHP and Cheyenne Light. Consequently, standalone resource planning results should also be considered in relation to joint resource planning results.
3. Ideally, there would be agreement among stakeholders as to how jointly-owned resources should be assigned to affiliated companies prior to construction.
4. Resource Planning will be conducted to support the recommended resource addition. If jointly–owned resources are recommended this recommendation will be supported by a joint resource plan. Independent resource plans will be conducted to support standalone resource additions.
5. BHP has committed to improving its internal modeling and forecasting capabilities for purposes of conducting its future planning activities.
    a. Use weather-normalized load projections for both energy and demand forecasts.
    b. Use an econometric or similar analysis for basis of low, mid and high load scenarios.
    c. Provide separate retail load and wholesale load data and projections.

3.2.3 Planning Reserve Capacity Agreement and Joint Resource Planning Process Analysis

Capacity expansion and production costing analyses were conducted to evaluate the potential benefits of a Planning Reserve Capacity Agreement and a joint planning process. Three cases were examined along with three scenarios to examine the risk associated with varying levels of load growth, high load, low load and step load growth:

- BHP Standalone case;
- Cheyenne Light Standalone case;
- Combined System with Independent Company Peaks case

- In this case, although the loads for the two systems were combined, the load forecast for each utility was kept in a respective zone and a reserve margin was calculated for each zone as well as a reserve margin for the entire system (taking into account both zones). For this analysis, the entire system is required to meet the 15% reserve margin but each zone's reserve margin could fall below the 15% reserve margin requirement essentially allowing the zones to share capacity.
- Future resources were added based on the combined system.

Table 3-4 shows that for the base load case, the anticipated savings from the planning reserve capacity agreement and the joint planning process over the 20-year planning horizon is $51.40 million. Table 3-4 shows the savings under the other load scenarios as well. Table 3-5 shows the resource portfolios for the BHP Standalone, Cheyenne Light Standalone and the Combined System with Independent Company Peaks cases.

Table 3-4
Scenario Results – Benefits of Planning Reserve Capacity Agreement and Joint Planning Process
(PVRR – $ millions)

	Base Load	**High Load**	**Low Load**	**Step Load**
BHP Standalone	$1,845.28	$2,056.64	$1,632.86	$2,033.02
Cheyenne Light Standalone	$1,115.68	$1,196.86	$1,037.13	$1,466.55
BHP plus Cheyenne Light Standalone Sum	**$2,960.96**	**$3,253.50**	**$2,669.99**	**$3,499.57**
Independent Company Peaks	$2,909.56	$3,194.82	$2,639.21	$3,412.97
Benefits of Planning Reserve Capacity Agreement and Joint Planning	**$51.40**	**$58.68**	**$30.78**	**$86.60**

Table 3-5
Resource Portfolios for Planning Reserve Capacity Agreement and Joint Planning Cases (Base Load Scenario)

Year	BHP Standalone	Cheyenne Light Standalone	Combined System with Independent Peaks
2015	Market – 25 MW	Market – 25 MW	Market – 50 MW
2016	Market – 25 MW	Market – 50 MW	Market – 50 MW
2017	Market – 25 MW	Market – 50 MW	Market – 75 MW
2018	Market – 25 MW	Market – 50 MW	Market – 75 MW
2019	Market – 50 MW	Market – 50 MW	Market – 75 MW
2020	Market – 50 MW	Market – 50 MW	Market – 75 MW
2021	Market – 50 MW	36 MW CT Market – 25 MW	Market – 100 MW
2022	Market – 50 MW	Market – 25 MW	Market – 100 MW
2023	Market – 50 MW	Market – 25 MW	Market – 100 MW
2024	100 MW Coal	Market – 25 MW	180 MW CT 30 MW Wind
2025		Market – 25 MW	
2026	Market – 25 MW	Market – 50 MW	Market – 25 MW
2027	Market – 25 MW	Market – 50 MW	Market – 25 MW
2028	Market – 25 MW	Market – 50 MW	Market – 50 MW
2029	Market – 25 MW	Market – 50 MW	Market – 50 MW
2030	Market – 50 MW	36 MW CT Market – 25 MW	Market – 75 MW
2031	Market – 50 MW	Market – 25 MW	Market – 75 MW
2032	Market – 50 MW	Market – 25 MW	Market – 75 MW
2033	Market – 50 MW	Market – 50 MW	Market – 100 MW
2034	Market – 75 MW	Market – 50 MW	Market – 100 MW
PVRR	**$1,845.28**	**$1,115.68**	**$2,909.56**

The resource portfolios for the other three scenarios are shown in Tables 3-6 through 3-8.

Table 3-6
Resource Portfolios for Planning Reserve Capacity Agreement and Joint Planning Cases (High Load Scenario)

Year	BHP Standalone	Cheyenne Light Standalone	Combined System with Independent Peaks
2015	Market – 50 MW	Market – 50 MW	Market - 75MW
2016	Market – 50 MW	Market – 50 MW	Market - 75MW
2017	36 MW CT Market – 25 MW	Market – 50 MW	Market - 100MW
2018	Market – 25 MW	Market – 50 MW	Market - 100MW
2019	Market – 50 MW	36 MW CT Market – 25 MW	Market - 125MW
2020	Market – 50 MW	Market – 25 MW	Market - 100MW 36 MW Simple Cycle
2021	Market – 50 MW	Market – 25 MW	Market - 125MW
2022	Market – 75 MW	Market – 50 MW	Market - 125MW
2023	Market – 75 MW	Market – 50 MW	30 MW Wind Market - 125 MW
2024	100 MW Coal Market – 25 MW	Market – 50 MW	180 MW CT Market -50MW
2025	Market – 25 MW	Market – 50 MW	Market - 50MW
2026	Market – 50 MW	36 MW CT Market – 25 MW	Market - 75MW
2027	Market – 50 MW	Market – 25 MW	Market - 100MW
2028	36 MW CT Market – 25 MW	Market – 50 MW	Market - 100MW
2029	Market – 50 MW	Market – 50 MW	Market - 25MW Coal - 100 MW
2030	Market – 50 MW	Market – 50 MW	Market - 50MW
2031	Market – 75 MW	36 MW CT Market – 25 MW	Market - 75MW 30 MW Wind
2032	36 MW CT Market – 50 MW	Market – 25 MW	Market - 100MW
2033	Market – 50 MW	Market – 50 MW	Market - 100MW
2034	Market – 75 MW	Market – 50 MW	Market - 125MW
PVRR	**$2,056.64**	**$1,196.86**	**$3,194.82**

Table 3-7
Resource Portfolios for Planning Reserve Capacity Agreement and Joint Planning Cases (Low Load Scenario)

Year	BHP Standalone	Cheyenne Light Standalone	Combined System with Independent Peaks
2015		Market – 25 MW	Market - 25MW
2016		Market – 25 MW	Market - 25MW
2017		Market – 25 MW	Market - 25MW
2018		Market – 25 MW	Market - 25MW
2019		Market – 25 MW	Market - 25MW
2020		Market – 50 MW	Market - 25MW
2021		Market – 50 MW	Market - 25MW
2022		Market – 50 MW	Market - 50MW
2023		Market – 50 MW	Market - 25MW
2024	Market – 50 MW	Market – 50 MW	Market - 75MW
2025	Market – 50 MW	Market – 50 MW	Market - 100MW
2026	Market – 50 MW	Market – 50 MW	Market - 100MW
2027	Market – 50 MW	36 MW CT Market – 25 MW	Market - 100MW
2028	Market – 50 MW	Market – 25 MW	Market - 100MW 30 MW Wind
2029	Market – 50 MW	Market – 25 MW	Market - 100MW
2030	Market – 50 MW	Market – 25 MW	Market - 125MW
2031	36 MW CT Market – 25 MW	Market – 25 MW	Market - 125MW
2032	Market – 25 MW	Market – 50 MW	Market - 125MW
2033	Market – 25 MW	Market – 50 MW	Market - 125MW
2034	Market – 25 MW	Market – 50 MW	Market - 125MW
PVRR	**$1,632.86**	**$1,037.13**	**$2,639.21**

Table 3-8
Resource Portfolios for Planning Reserve Capacity Agreement and Joint Planning Cases (Step Load Scenario)

Year	BHP Standalone	Cheyenne Light Standalone	Combined System with Independent Peaks
2015	36 MW CT Market – 25 MW	36 MW CT Market – 50 MW	180 MW CT
2016	Market – 50 MW	Market – 50 MW	
2017	Market – 50 MW	36 MW CT Market – 25 MW	
2018	Market – 50 MW	Market – 25 MW	Market - 25MW
2019	Market – 50 MW	Market – 25 MW	Market - 25MW
2020	Market – 50 MW	Market – 50 MW	30 MW Wind Market - 25MW
2021	Market – 50 MW	Market – 50 MW	Market - 50MW
2022	Market – 75 MW	Market – 50 MW	Market - 50MW
2023	Market – 50 MW	Market – 50 MW	Market - 50MW
2024	100 MW Coal Market – 25 MW	100 MW Coal	Market - 125MW
2025	Market – 25 MW		Market - 125MW
2026	Market – 25 MW		Market - 125MW
2027	Market – 25 MW		Market - 50MW Coal - 100MW
2028	Market – 50 MW		Market - 50MW
2029	Market – 50 MW		Market - 75MW
2030	Market – 50 MW		Market - 100 MW 30 MW Wind
2031	Market – 75 MW		Market - 100MW
2032	36 MW CT Market – 25 MW		Market - 125MW
2033	Market – 50 MW	Market – 25 MW	Market - 125MW
2034	Market – 50 MW	Market – 25 MW	36 MW Simple Cycle Market - 100MW
PVRR	**$2,033.02**	**$1,466.55**	**$3,412.97**

In summary, the potential planning reserve capacity agreement and joint resource planning benefits include:

- Providing an economic option for meeting planning reserve requirements rather than purchasing firm energy for short-term contingencies on the market at a higher price.
- The selling party benefits by receiving a capacity payment.
- The procuring party can purchase economy energy to meet its energy needs.

- The agreement does not obligate utilities to sell capacity to each other.
- The agreement expands both parties' ability to acquire needed capacity.
- Future resource acquisitions may "fit" the resource need because resources are sized for a larger system.

3.2.4 Economy Energy Service Agreement Analysis

The existing Economy Energy Service Agreement allows BHP and Cheyenne Light to voluntarily sell and buy economy energy services among themselves. To determine the benefits of this agreement, three cases were compared in production cost modeling. These three cases were:

- BHP standalone system;
- Cheyenne Light standalone system;
- Combined System with Independent Company Peaks case
    - The combined system resource portfolio included the future resources included in the BHP standalone portfolio plus the future resources included in the Cheyenne Light standalone portfolio.

In order to determine the savings from the existing Economy Energy Service Agreement, the difference in the purchased power costs as well as the differences incurred in fuel expense and variable O&M expense were calculated. The total savings due to the agreement can be expressed as shown in the formula below:

> Savings due to Economy Energy Service Agreement = Total difference in purchased power cost minus (the sum of the difference in variable O&M expense plus the difference in fuel expense).

The savings in the base load scenario are expected to be $16.19 million. The savings for each of the load scenarios are shown in Table 3-9.

Table 3-9
Scenario Results – Benefits of Economy Energy Service Agreement
(PVRR – $ millions)

	Base Load	High Load	Low Load	Step Load
Purchased Power Savings for Combined System	$121.36	$141.11	$111.69	$111.91
Additional Fuel Costs for Combined System	($75.63)	($90.07)	($71.40)	($70.96)
Additional Variable O&M Costs for Combined System	($29.54)	($26.59)	($21.72)	($22.76)
Benefits of Economy Energy Service Agreement	**$16.19**	**$24.45**	**$18.57**	**$18.19**

3.3 Generation Holding Company

The primary incremental benefit of creating a generation holding company is to combine the loads of BHP and Cheyenne Light into one forecast, thus creating potential for diversity benefits in addition to the benefits of reserve sharing and joint planning. Studies were performed to evaluate the potential benefits of a seamless combination of BHP and Cheyenne Light. In addition, the issues related to the creation of a generation holding company were examined and discussed in depth in the stakeholder process and a list of potential implementation requirements was presented. This list of issues involves numerous financial, legal and regulatory steps which could impose substantial additional costs and uncertainty as to when such a process might be completed. In light of the concerns related to the cost differential between BHP and Cheyenne Light, it was determined that the collaborative's efforts should focus on quantifying the potential benefits of joint planning and the reserve sharing agreement. However, the sections below document what the company expects are issues that will need to be addressed to create a generation holding company.

A generation holding company (GenCo) would own the BHP and Cheyenne Light generation assets and jointly operate them for the benefit of both companies.

Such a GenCo could be structured in one of two ways:

1. Partially owned by each utility based on the value of contributed assets.
2. An affiliate of BHP and Cheyenne Light.

Both companies would enter into an arrangement whereby they make a capital contribution to a newly formed entity (GenCo) in exchange for an equity interest. The new entity would most likely be in the form of a limited liability company (LLC). The formation of GenCo would be accomplished by a cash contribution as its initial equity capital. However, the lion's share of equity capital would come in the form of the generation assets being contributed. This property contribution would be treated for income tax purposes as a contribution to capital and as a result there is no tax consequence. Forming a GenCo in this manner is the most efficient approach from both a business and tax perspective. The initial ownership share would most likely be determined based on the net book value of the assets contributed. An agreement would be entered into that, among other things, would govern operation of the plant facilities and allocate plant capacity and energy produced. All relevant existing contracts (e.g., fuel contracts) would be assigned to the GenCo or consents obtained where necessary from all applicable parties agreeing to such assignment. The time and cost associated with the formation of a GenCo including determining the appropriate ownership structure, drafting agreements and completing the necessary transactions and filings with FERC and state regulatory agencies is expected to take a significant amount of time and be costly.

A myriad of issues need to be examined for the generation holding company alternative including legal and tax, financial, regulatory, power marketing (including existing contracts), transmission, environmental, and operational.

3.3.1 Legal and Federal Tax Issues

Prior to establishing a GenCo, a comprehensive review of all existing contracts and agreements would be required to ensure that transferring the generation assets to a GenCo did not violate any of the terms of these agreements or contracts. In the event that a contract or agreement precluded the transfer of an asset, the risk associated with opening the contract and re-establishing terms with the GenCo would need to be evaluated. It is estimated that this review would take a significant amount of time and require legal resources to complete the review.

As mentioned above, the transfer of assets to a GenCo could be made on a tax-free basis for federal income tax purposes. Tax basis original cost of the assets contributed and accumulated depreciation including any prior bonus depreciation would carry over to GenCo along with the prescribed depreciable lives and methods. In essence, GenCo would be “stepping into the shoes” of BHP and Cheyenne Light. Bonus depreciation is simply an acceleration of tax depreciation that would have otherwise occurred over the tax life of the property. Recently, 50% bonus depreciation was extended by Congress and signed into law by the President for qualified plant investments placed in service by December 31, 2013, with certain exceptions applicable to qualified projects that are placed in service by December 31, 2014. Thus, 50% of the cost of qualified projects can be deducted for tax purposes in 2013 when they are placed in service. The other 50% is depreciated over the life of the property as prescribed under tax law.

Accelerated tax depreciation including bonus depreciation will exceed depreciation recorded for book/regulatory purposes producing a temporary difference to which the federal income tax rate is applied, resulting in deferred income taxes. The cumulative effect of these deferred income taxes results in accumulated deferred income taxes (ADIT). ADIT would follow the related assets as a result of the tax-free transfer and be carried over to the books and records of GenCo. Thus, there would be no re-setting of the applicable ADIT.

From a tax perspective, the cost to complete the transfer of assets would not be significant.

3.3.2 Financial Issues

One of the many decisions that would need to be made for the GenCo is the manner in which capacity and energy would be priced. One alternative is the Generation Company Formula Rate; the other is the Combined Company Formula Rate.

- Generation Company Formula Rate. A combined capacity and energy rate that passes the system cost to the two utilities based on usage. The capacity rate would be based on the contributed assets with its own return on Equity (ROE) that is independent from the ROEs for BHP and Cheyenne Light. This rate is likely to require FERC approval.
- Combined Company Formula Rate. This rate would be similar to the Generation Company Formula Rate; however, the capacity rate would be established based on each utility's contributed assets and their respective ROE (revenue requirement). The two utilities' revenue requirement would be used for the capacity rate. This rate is likely to require FERC approval.

There would be an "All Requirements" long-term contract between the GenCo and each of BHP and Cheyenne Light to provide all of the energy resources.

3.3.3 Regulatory Issues

We anticipate that rate cases would be required in both South Dakota and Wyoming to transfer the generation assets to the GenCo and to rate base the investment in that company based on the contributed assets. Creating a GenCo with rates to the two utilities is expected to require FERC approval. These dockets can take a significant amount of time and be costly to complete.

3.3.4 State and Local Tax Issues

With respect to other taxes that are related primarily to sales and use taxes, the formation of GenCo would be completed on a tax-free basis. Subsequent transactions involving sales and use tax could be handled in a manner that is consistent with such treatment pre-formation. That is to say, if a transaction was sales taxable pre-formation of GenCo, that same transaction would be taxable post formation. Use tax is applied by the purchaser or user of an item in the event the vendor doesn't charge sales tax. Thus, when the transaction is taxable, a tax cost is incurred whether imposed by the seller or provider of goods and services or self-imposed by the buyer or user.

From a property tax standpoint, there would essentially be a shift of the liability from BHP, particularly in Wyoming, to GenCo and similarly a shift from Cheyenne Light to GenCo for the contributed generation assets. GenCo would require two additional state-assessed property tax returns to be filed:

1) one to South Dakota for the Ben French CTs, the diesel-powered portable generators, and the Lange CT
2) one to Wyoming for Wygen I, II and III, CPGS, Neil Simpson #2, Wyodak and the Neil Simpson CT.

These returns are not required to be filed currently as the generation properties are now incorporated in the returns filed by BHP and Cheyenne Light along with all of their other assets. Additional staff may be required to complete these two new returns.

As mentioned above, there would be a shifting of the property tax liability from BHP and Cheyenne Light to GenCo without any measurable difference between pre- and post-formation. Our current estimate is there would be no material change in overall property tax expense.

3.3.5 Power Marketing Issues

Currently, power marketing proceeds are split between BHP and the customers in BHP's service territory. The formation of a GenCo would likely not change this method of allocation of proceeds; however, it is likely that the opportunity to sell power to the market will be reduced as a result of the formation of a generation pool reducing revenue to BHP and its customers. An analysis to determine the amount of revenue that would be lost and the method of compensating BHP and its customers for this loss would need to be completed.

In addition to selling power that is generated by BHP's assets, Generation Dispatch and Power Marketing trade non-asset power. How the proceeds from this trading activity are allocated would need to be determined.

3.3.6 Transmission Issues

The formation of a GenCo between BHP and Cheyenne Light would likely have no impact on current transmission assets and tariffs. Because FERC approval would be required if transmission assets or contracts were transferred to the GenCo, the approach would be to leave the current transmission agreements and assets with the individual utilities. However, depending on how the GenCo is structured and operated, further study may be required to evaluate transmission needs under a generation pool arrangement. This study would be conducted by the transmission provider that operates the system that service is being requested of and is billed on a time and materials basis plus deposits as identified in the transmission tariff.

3.3.7 Environmental Issues

All air permits (Title V and PSD Construction permits, for those entities that have not yet received a Title V such as Wygen III and CPGS), NPDES permits and stormwater permits would need to recognize the multiple owners and identify the responsible party that will be the operator. The acid rain permit owner information would need to be updated on EPA's website. Environmental compliance plans such as SPCC (spill plan) and ammonia risk management plans would need to be updated.

For the permits, a simple letter describing the new owner is required; this process will take about two months. The acid rain permit is updated electronically. Compliance plans would need to be updated to reflect the new owners. No risk is anticipated and there are no opportunities for any party to intervene.

3.3.8 Operational Issues

Under an ownership structure where the GenCo is owned by the two utilities, future capital resources of the GenCo could be shared equally or allocated based on the resource plans of the two utilities. Based on the resource needs of the combined resource plan, each utility would be responsible for contributing its portion of the required resource. This would increase the investment of each utility in the GenCo. The GenCo would construct the required facility. Future contributions would change the revenue requirements of each of the utilities.

BHP and Cheyenne Light currently utilize first mortgage bonds to provide long-term debt financing for their utility operations. The utility assets are pledged as security under the terms of the bond indenture applicable to each utility. The pledged assets include generation currently owned by each utility. In order to transfer utility-owned generation to an affiliate (GenCo) the generation would likely need to be "purchased" and bonds repaid before it would be released from the indentures. Whether existing generation is transferred or not, under an ownership structure where the GenCo is an affiliate of the two utilities, future capital resources of the GenCo would be funded through its issuance of debt and equity that would then be recovered through the formula rates. The future cost of capital for the GenCo should be similar to that available to the utilities since the PPAs would be with the utilities.

The formula rates for each utility will vary based on the load of each system and whether or not the utility is using more or less as compared to what that utility contributed. All of the costs of the GenCo would be passed to the utilities and the profit of the GenCo would be distributed to the owners based on their revenue requirement and ownership. The respective utilities would have their portion of the revenues distributed based on their contributed assets and the cost to the utilities would be based on their portion of the system cost.

3.3.9 Combined System Analysis

To evaluate the potential savings associated with a generation holding company (combined dispatch and resource planning of both utilities), capacity expansion and production costing modeling was undertaken for three cases:

- Cheyenne Light standalone system,
- BHP standalone system

- Combined system – in this case resources are planned for both systems jointly assuming a combined load forecast and a requirement for a 15% reserve margin for the combined system.

Four scenarios were examined:

- Base Load
- High Load
- Low Load
- Step Load

The assumptions used in these analyses are shown in Volume II and the Load and Resource Balances for the four scenarios examined are included in Appendix B.

Table 3-10 shows the potential benefits of pooling in the base load case, as represented by the difference between the present value of revenue requirements (PVRR) for the combined system and the sum of the two standalone cases. This difference is estimated to be more than $105 million over the entire 20-year planning period. These cost savings are due both to differences in resources added and the efficiencies of combined operation. Resources added over the planning period for the base load cases are shown in Table 3-11. A major benefit of the pooling arrangements assumed in the combined system modeling resulted from capturing the benefit of load diversity resulting from Cheyenne Light and BHP peaking at different times. This benefit was not assumed to be present in the joint planning cases, though sharing of reserves was. BHP and Cheyenne Light will seek to identify the potential load diversity benefits stemming from joint planning in the future as discussed on page 17.

Table 3-10
Scenario Results – Combined System Analysis
(PVRR – $ millions)

	Base Load	**High Load**	**Low Load**	**Step Load**
BHP Standalone System	$1,845.28	$2,056.64	$1,632.86	$2,033.02
Cheyenne Light Standalone System	$1,115.68	$1,196.86	$1,037.13	$1,466.55
BHP Plus Cheyenne Light Standalone Cases	$2,960.96	$3,253.50	$2,669.99	$3,499.57
Combined Dispatch System	$2,855.07	$3,153.37	$2,630.97	$3,353.65
Benefits of Pooling	**$105.89**	**$100.12**	**$39.03**	**$145.93**

Table 3-11
Resource Portfolios for Base Load Cases

Year	BHP Standalone	Cheyenne Light Standalone	Combined System
2015	Market – 25 MW	Market – 25 MW	
2016	Market – 25 MW	Market – 50 MW	Market – 25 MW
2017	Market – 25 MW	Market – 50 MW	Market – 50 MW
2018	Market – 25 MW	Market – 50 MW	Market – 50 MW
2019	Market – 50 MW	Market – 50 MW	Market – 25 MW
2020	Market – 50 MW	Market – 50 MW	Market – 50 MW
2021	Market – 50 MW	36 MW CT Market – 25 MW	Market – 50 MW
2022	Market – 50 MW	Market – 25 MW	Market – 50 MW
2023	Market – 50 MW	Market – 25 MW	Market – 75 MW
2024	100 MW Coal	Market – 25 MW	Market – 125 MW Wind – 30 MW
2025		Market – 25 MW	Market – 125 MW
2026	Market – 25 MW	Market – 50 MW	Market – 125 MW
2027	Market – 25 MW	Market – 50 MW	37 MW CT Market – 100 MW
2028	Market – 25 MW	Market – 50 MW	37 MW CT Market – 75 MW
2029	Market – 25 MW	Market – 50 MW	Market – 100 MW
2030	Market – 50 MW	36 MW CT Market – 25 MW	Market – 100 MW
2031	Market – 50 MW	Market – 25 MW	Market – 125 MW
2032	Market – 50 MW	Market – 25 MW	Market – 125 MW
2033	Market – 50 MW	Market – 50 MW	Market – 125 MW
2034	Market – 75 MW	Market – 50 MW	37 MW CT Market – 125 MW
PVRR	**$1,845.28**	**$1,115.68**	**$2,855.07**

The resource portfolios for the other three scenarios are shown in Tables 3-12 through 3-14.

Table 3-12
Resource Portfolios for High Load Cases

Year	BHP Standalone	Cheyenne Light Standalone	Combined System
2015	Market – 50 MW	Market – 50 MW	Market – 25 MW
2016	Market – 50 MW	Market – 50 MW	Market – 50 MW
2017	36 MW CT Market – 25 MW	Market – 50 MW	Market – 75 MW
2018	Market – 25 MW	Market – 50 MW	Market – 75 MW
2019	Market – 50 MW	36 MW CT Market – 25 MW	Market – 75 MW
2020	Market – 50 MW	Market – 25 MW	Market – 100 MW
2021	Market – 50 MW	Market – 25 MW	Market – 100 MW
2022	Market – 75 MW	Market – 50 MW	Market – 125 MW
2023	Market – 75 MW	Market – 50 MW	30 MW Wind 180 MW CT
2024	100 MW Coal Market – 25 MW	Market – 50 MW	Market – 25 MW
2025	Market – 25 MW	Market – 50 MW	Market – 50 MW
2026	Market – 50 MW	36 MW CT Market – 25 MW	Market – 50 MW
2027	Market – 50 MW	Market – 25 MW	Market – 75 MW
2028	36 MW CT Market – 25 MW	Market – 50 MW	Market – 100 MW
2029	Market – 50 MW	Market – 50 MW	Market – 125 MW
2030	Market – 50 MW	Market – 50 MW	100 MW Coal Market – 25 MW
2031	Market – 75 MW	36 MW CT Market – 25 MW	30 MW Wind Market – 50 MW
2032	36 MW CT Market – 50 MW	Market – 25 MW	Market – 75 MW
2033	Market – 50 MW	Market – 50 MW	Market – 75 MW
2034	Market – 75 MW	Market – 50 MW	Market – 125 MW
PVRR	**$2,056.64**	**$1,196.86**	**$3,153.37**

Table 3-13
Resource Portfolios for Low Load Cases

Year	BHP Standalone	Cheyenne Light Standalone	Combined System
2015		Market – 25 MW	
2016		Market – 25 MW	
2017		Market – 25 MW	
2018		Market – 25 MW	
2019		Market – 25 MW	
2020		Market – 50 MW	
2021		Market – 50 MW	
2022		Market – 50 MW	
2023		Market – 50 MW	
2024	Market – 50 MW	Market – 50 MW	Market – 50 MW
2025	Market – 50 MW	Market – 50 MW	Market – 50 MW
2026	Market – 50 MW	Market – 50 MW	Market – 50 MW
2027	Market – 50 MW	36 MW CT Market – 25 MW	Market – 50 MW
2028	Market – 50 MW	Market – 25 MW	30 MW Wind Market – 50 MW
2029	Market – 50 MW	Market – 25 MW	Market – 75 MW
2030	Market – 50 MW	Market – 25 MW	Market – 75 MW
2031	36 MW CT Market – 25 MW	Market – 25 MW	Market – 75 MW
2032	Market – 25 MW	Market – 50 MW	Market – 75 MW
2033	Market – 25 MW	Market – 50 MW	Market – 75 MW
2034	Market – 25 MW	Market – 50 MW	Market – 100 MW
PVRR	**$1,632.86**	**$1,037.13**	**$2,630.97**

Table 3-14
Resource Portfolios for Step Load Cases

Year	**BHP Standalone**	**Cheyenne Light Standalone**	**Combined System**
2015	36 MW CT Market – 25 MW	36 MW CT Market – 50 MW	Market – 100 MW
2016	Market – 50 MW	Market – 50 MW	Market – 100 MW
2017	Market – 50 MW	36 MW CT Market – 25 MW	37 MW CT Market – 100 MW
2018	Market – 50 MW	Market – 25 MW	Market – 100 MW
2019	Market – 50 MW	Market – 25 MW	Market – 100 MW
2020	Market – 50 MW	Market – 50 MW	Market – 100 MW
2021	Market – 50 MW	Market – 50 MW	Market – 125 MW
2022	Market – 75 MW	Market – 50 MW	30 MW Wind Market – 125 MW
2023	Market – 50 MW	Market – 50 MW	180 MW CT
2024	100 MW Coal Market – 25 MW	100 MW Coal	Market – 25 MW
2025	Market – 25 MW		Market – 50 MW
2026	Market – 25 MW		Market – 50 MW
2027	Market – 25 MW		Market – 50 MW
2028	Market – 50 MW		Market – 75 MW
2029	Market – 50 MW		100 MW Coal
2030	Market – 50 MW		30 MW Wind
2031	Market – 75 MW		
2032	36 MW CT Market – 25 MW		Market – 25 MW
2033	Market – 50 MW	Market – 25 MW	Market – 25 MW
2034	Market – 50 MW	Market – 25 MW	Market – 75 MW
PVRR	**$2,033.02**	**$1,466.55**	**$3,353.65**

3.4 Environmental Scenario Analysis

During the Generation Pool Study stakeholder meeting held July 31, 2013, the issue of what results would have been obtained if an environmental scenario had been analyzed in conjunction with the Generation Pool Study was raised. If carbon costs were considered, how would the resulting resource portfolios change and what would be the difference in costs? Since an environmental scenario was run in both the 2011 Cheyenne Light IRP and the 2011 Black Hills Power IRP, it is instructive to look at those results to determine the differences in resource portfolios and costs.

3.4.1 Assumptions

The most significant assumptions for the environmental scenario include emission costs and correlated natural gas prices and market prices. The analysis that Ventyx undertoook in evaluating a carbon tax reflected that a premium would be placed on natural gas-fired resources (as compared to coal-fired generation). In addition, Ventyx projected that both market prices (which reflect natural gas resources at the margin) and the natural gas prices themselves will be higher than in the base case assumptions.

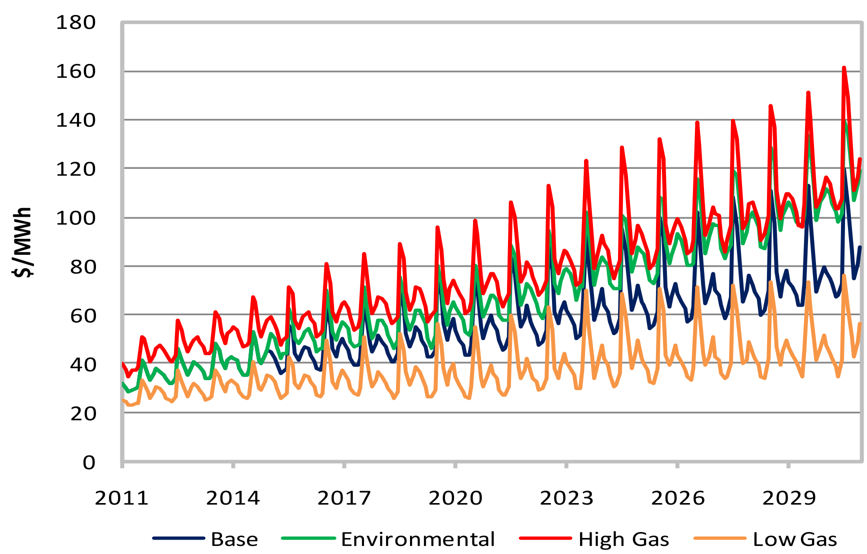
3.4.2 Natural Gas Prices

BHP used the natural gas price forecasts from the Ventyx 2011 Spring Reference Case for the base case. Natural gas prices used in the environmental scenario were correlated to markets that include emissions costs. Cheyenne Light used the natural gas price forecasts from the Ventyx 2010 Fall Reference Case for the base case and the Preferred Plan. Natural gas prices used in the environmental scenario were correlated to markets that include emissions costs.

3.4.3 Market Prices

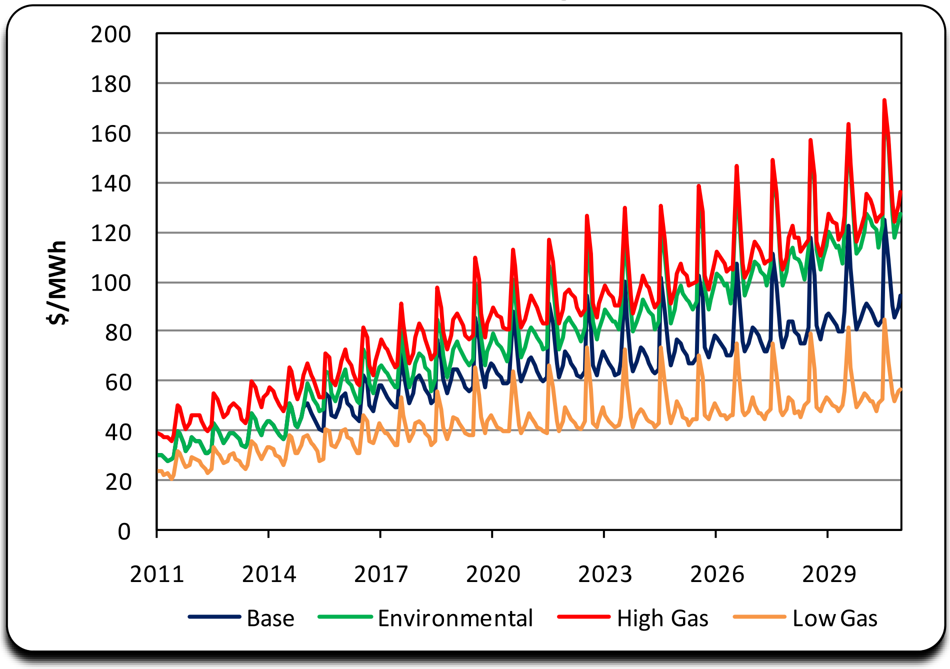
From the BHP 2011 IRP: Electricity price estimates for the Wyoming region were derived from Ventx's 2011 Spring Reference Case and are the basis on which BHP's market transactions were priced. The on-peak electricity prices for Wyoming are shown in Figure 3-2. Values are shown for the four scenarios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

Figure 3-2
Reference Case – On-Peak Electricity Prices – Wyoming Region (copy of Figure 3.2 from the BHP 2011 IRP)



From the Cheyenne Light 2011 IRP: Electricity price estimates for the Wyoming region were derived from Ventyx's 2010 Fall Reference Case and are the basis on which Cheyenne Light's market transactions were priced. The on-peak electricity prices for Wyoming are shown in Figure 3-3. Values are shown for the four scenarios that require the development of correlated natural gas and market prices – base, environmental, low gas and high gas.

Figure 3-3
Reference Case – On-Peak Electricity Prices – Wyoming Region (copy of Figure 3.2 from the Cheyenne Light 2011 IRP)



Source: Ventyx

3.4.4 Emissions Costs

Both IRPs assumed that a carbon tax would be implemented in 2015 and escalate over time. The values are based on the Ventyx assumptions which are:

- CO_2 emission tax begins in 2015
- The national requirement is an 80% reduction below 2005 CO_2 emission levels by 2050
- A national Renewable Portfolio Standard (RPS) is enacted that begins in 2015
- Under the national RPS, for 2020 and later, the target is 12% of retail sales for utilities with load greater than 4 TWh

The values used as shown in the Black Hills 2011 IRP in Section 3.6, Table 3-4 and the Cheyenne Light 2011 IRP in Section 3.6, Table 3-4 are replicated below in Table 3-15.

Table 3-15
Carbon Tax Assumptions
(Environmental Scenario Only)

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

3.4.5 Analysis

When Ventyx conducted the analyses for BHP and Cheyenne Light, they completed capacity expansion modeling and production cost modeling for a preferred plan and several scenarios, including an environmental scenario. The resource portfolios for all of the scenarios that were evaluated are reflected in Table 7-2 of the BHP 2011 IRP and Table 7-1 of the Cheyenne Light 2011 IRP. For the purposes of this document, the resource portfolios from those tables are shown in Table 3-16 only for the Preferred Plans and the Environmental Scenario. For BHP, the first year in which there is any difference in the resource portfolios between the two plans is 2024. In the Preferred Plan, a 100 MW coal unit is added in 2024. In the Environmental Scenario, two 36 MW CTs and a 30 MW Wind facility are added in 2024.

For Cheyenne Light, the first year in which there is a difference in resource portfolios is 2018. In Cheyenne Light's Preferred Plan, a 36 MW CT is installed in 2018, while in the Environmental Scenario, 30 MW of wind are installed in 2018 and a 36 MW CT is installed in 2019. Therefore, with the addition of the Cheyenne Prairie Generating Station, BHP is effectively building out the Environmental Scenario. Cheyenne Light's Preferred Plan also builds natural gas resources in a comparable manner to the Environmental Scenario.

Table 3-16
Optimal Expansion Plans
BHP 2011 IRP (from Table 7-2) and Cheyenne Light 2011 IRP (from Table 7-1)

	BHP			Cheyenne Light	
Year	**Preferred Plan**	**Environmental**		**Preferred Plan (3 CTs in 2014)**	**Environmental**
2011				Market 25 MW	Market 25 MW
2012	Market 25 MW	Market 25 MW		Market 50 MW	Market 50 MW
2013	Market 25 MW	Market 25 MW		Market 50 MW	Market 50 MW
2014	CC Conv 55 MW Market 25 MW	CC Conv 55 MW Market 25 MW		3 CTs –109 MW	CT – 90 MW
2015	Market 25 MW	Market 25 MW			Market 25 MW
2016	Market 25 MW	Market 25 MW			Market 25 MW
2017	Market 50 MW	Market 50 MW			Market 25 MW
2018	Market 50 MW	Market 50 MW			CT – 36 MW
2019	Market 50 MW	Market 50 MW		Wind 30 MW Market 25 MW	
2020	Market 50 MW	Market 50 MW		Market 25 MW	
2021	Market 50 MW	Market 50 MW		Market 25 MW	
2022	Market 50 MW	Market 50 MW		36 MW CT	
2023	Market 50 MW	Market 50 MW			Wind 30 MW
2024	Coal 100 MW	2 CTs @ 36 MW each; Wind 30 MW, Market 25 MW			Market 25 MW
2025		Market 25 MW			Market 25 MW
2026	Market 25 MW	Market 50 MW			Market 25 MW
2027	Market 25 MW	Market 50 MW			Market 25 MW
2028	Market 25 MW	Market 50 MW Wind 30 MW		Market 25 MW	Wind – 30 MW Market 25 MW
2029	Market 25 MW	Market 50 MW		Market 25 MW	CT – 36 MW
2030	CT 36 MW	2 CTs @ 36 MW Wind 30 MW		36 MW CT	

Production cost modeling completed for the IRPs provided deterministic PVRR values for each of the scenarios evaluated using base case assumptions. This means that the resource portfolio determined in the capacity expansion modeling for a specific future scenario (i.e., environmental, high load, high gas, etc.) is evaluated using the base case assumptions. Therefore the difference in the PVRR between the Preferred Plan and the Environmental Scenario reflects the difference in cost of the resource portfolios and does not include other changed costs related to environmental regulation or new taxes. Figures 3-4 and 3-5 show these results for the BHP and Cheyenne Light IRP's Preferred Plans and environmental scenarios.

Figure 3-4
BHP Deterministic PVRR for Preferred Plan and Environmental Scenario

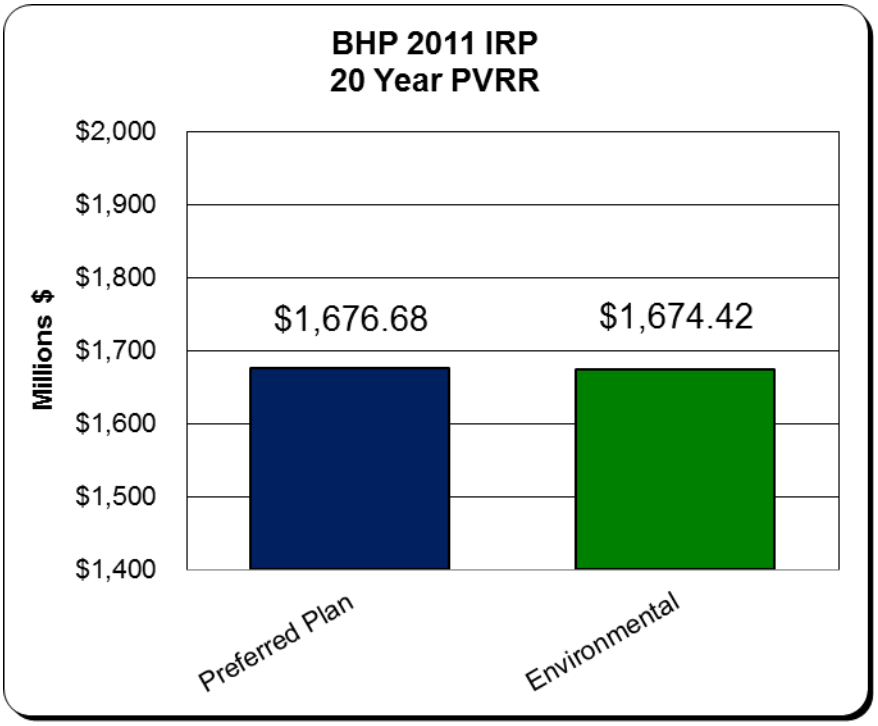


Figure 3-5
Cheyenne Light Deterministic PVRR for Preferred Plan and Environmental Scenario

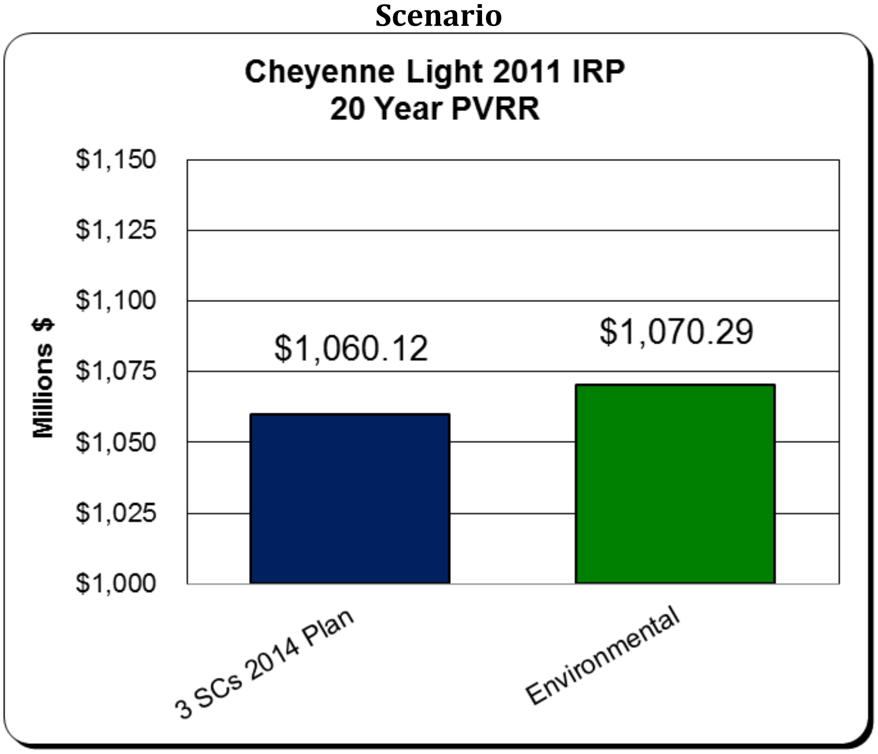


Table 3-17
20 Year PVRR Comparison of Preferred Plans versus Environmental Scenarios
BHP 2011 IRP and Cheyenne Light 2011 IRP
($ Millions)

	Preferred Plan	Environmental	% Difference
BHP	$1,676.68	$1,674.42	(.13)
Cheyenne Light	$1,060.12	$1,070.29	0.96

Table 3-17 shows that under an environmental scenario, the PVRR for BHP is expected to go down over the course of the 20-year planning period. Over that same planning period, under an environmental scenario, the PVRR for Cheyenne Light are expected to increase.

This means that the cost differential that exists today between the two utilities would remain. That cost differential would be expected to widen if a carbon tax were implemented in the manner reflected in the environmental scenario.

4.0 Conclusions and Recommendations

This generation pool study was conducted in accordance with the Stipulation and Agreement between BHP, Cheyenne Light and the Wyoming OCA. Other stakeholders that participated in the study included the Staff of the SDPUC and the Black Hills Industrial Interveners. The stakeholders met on several occasions, discussed the issues to be analyzed, agreed upon the assumptions and the methods to be used to complete the analysis and contributed comments to this report.

The collaborative completed a system cost analysis, analyzed the continued current operation of BHP and Cheyenne Light with the current agreements and with the addition of a planning reserve capacity agreement and joint planning, and examined the costs and benefits of creating a generation holding company.

The system cost analysis showed that the costs for BHP were lower than the system costs for Cheyenne Light in all years that were analyzed. If a generation pool were developed, historical power supply cost differences will need to be addressed to ensure future pricing equity (see Table 4-1).

Table 4-1
System Cost Analysis ($/MWh)

Year	BHP	Cheyenne Light
2013	44.91	51.74
2014	48.92	60.00
2015	53.78	68.01
2016	55.96	69.78
2017	55.50	68.20

Analyses were conducted to determine the savings under a combined system (dispatch and joint planning) as well as with the current and planned agreements between BHP and Cheyenne Light. This modeling showed that the agreements capture at least 60 percent of the possible savings that would be realized through a generation holding company without the legal and financial obstacles that would need to be overcome in order to form that generation pool (see Table 4-2).

Table 4-2
Base Load Scenario – Combined System Savings Versus Savings from Agreements (PVRR – $ millions)

	Base Load Scenario	Source of Number
Combined System Savings	$105.89	Table 3-10
Savings from Planning Reserve Capacity Agreement and Joint Planning Process	$51.40	Table 3-4
Savings from Economy Energy Service Agreement	$16.19	Table 3-9
Savings not realized from pooling	$38.3 or less than $2 million per year. About 1% of the total PVRR over the 20-year period.	

The resource portfolios developed for all of the Base Load Scenarios are shown in Table 4-3.

Table 4-3
Resource Portfolios for Planning Reserve Capacity Agreement and Joint Planning and Combined System Cases (Base Load Scenario)

Year	BHP Standalone	Cheyenne Light Standalone	Planning Reserve Capacity Agrmt and Joint Planning	Combined System
2015	Market – 25 MW	Market – 25 MW	Market - 50MW	
2016	Market – 25 MW	Market – 50 MW	Market - 50MW	Market – 25 MW
2017	Market – 25 MW	Market – 50 MW	Market- 75MW	Market – 50 MW
2018	Market – 25 MW	Market – 50 MW	Market - 75MW	Market – 50 MW
2019	Market – 50 MW	Market – 50 MW	Market - 75MW	Market – 25 MW
2020	Market – 50 MW	Market – 50 MW	Market - 75MW	Market – 50 MW
2021	Market – 50 MW	36 MW CT Market – 25 MW	Market - 100MW	Market – 50 MW
2022	Market – 50 MW	Market – 25 MW	Market - 100MW	Market – 50 MW
2023	Market – 50 MW	Market – 25 MW	Market - 100MW	Market – 75 MW
2024	100 MW Coal	Market – 25 MW	180 MW CT 30 MW Wind	Market – 125 MW Wind – 30 MW
2025		Market – 25 MW		Market – 125 MW
2026	Market – 25 MW	Market – 50 MW	Market - 25MW	Market – 125 MW
2027	Market – 25 MW	Market – 50 MW	Market - 25MW	37 MW CT Market – 100 MW
2028	Market – 25 MW	Market – 50 MW	Market - 50MW	37 MW CT Market – 75 MW
2029	Market – 25 MW	Market – 50 MW	Market - 50MW	Market – 100 MW
2030	Market – 50 MW	36 MW CT Market – 25 MW	Market - 75MW	Market – 100 MW
2031	Market – 50 MW	Market – 25 MW	Market - 75MW	Market – 125 MW
2032	Market – 50 MW	Market – 25 MW	Market - 75MW	Market – 125 MW
2033	Market – 50 MW	Market – 50 MW	Market - 100MW	Market – 125 MW
2034	Market – 75 MW	Market – 50 MW	Market - 100MW	37 MW CT Market – 125 MW
PVRR	**$1,845.28**	**$1,115.68**	**$2,909.56**	**$2,855.07**

The purpose of this study was to determine if a generation pool would provide benefits for the customers of both BHP and Cheyenne Light. The study allowed the parties to evaluate the benefits and risks of the operation of the utilities with agreements as compared to the formation of a generation pool. This study showed that the existing agreements between BHP and Cheyenne Light have brought significant benefits to customers and improved utility operations. The study also showed that the proposed Planning Reserve Capacity agreement and joint resource planning for future resource acquisitions may provide even further cost savings for customers. In particular, the analysis that evaluated the benefit of combining the utilities' peak demand forecasts identified additional possible savings due to load diversity.

Further savings may be possible if a generation pool were formed; however, the risks and costs of such a formation will likely outweigh the potential benefits. Given the differences in the utilities system costs and that at least 60 percent of the savings of a generation pool can be realized through agreements, BHP and Cheyenne Light recommend that the utilities enter into a Planning Reserve Capacity Agreement and utilize Joint Planning Principles for future resource acquisitions.

Appendix A

Merging BHP/Cheyenne Light

Merging BHP and Cheyenne Light into one utility requires consideration of all of the issues examined under the discussion of a generation holding company as well as additional considerations in the areas of legal, financial, regulatory, transmission, and power marketing. Additional requirements related to this issue were also presented and discussed in the stakeholder meetings.

In-depth analysis of these issues was not conducted during this study; the issues are solely being identified in the paragraphs below. In addition to FERC approval, Commission approval would be required in both South Dakota and Wyoming.

A.1 Financial Issues

In addition to those issues examined for the generation holding company, the companies would need to examine:

- How BHP's and Cheyenne Light's debt obligations would impact a merger
- Issues around goodwill recovery for Wyodak
- If a restatement would be required
- If the existing indentures allow the utilities to be merged and the associated risks

A.2 Regulatory Issues

In addition to those issues examined for the generation holding company, the companies would need to examine:

- How its rates would be structured. Would there be tariffs for different zones or would tariffs be set up for a Wyoming certificated territory and a South Dakota certified territory?
- How would adjustment clauses be structured – and are they, in fact, allowed?
- If the demand-side management programs should be combined or should they stay as separate programs
- If air permits would need to be transferred
- How BHP's SEC registrant obligations such as reporting obligations might change

A.3 Power Marketing Issues

In addition to those issues examined for the generation holding company, the companies would need to examine:

- How Power Marketing would be managed. Would there be one set of books for the merged company or a service company?

A.4 Transmission Issues

In addition to those issues examined for the generation holding company, the companies would need to examine:

- The process to combine all transmission assets and agreements under one utility.

A.5 Operational Issues

In addition to those issues examined for the generation holding company, the companies would need to examine:

- If a merger would require renegotiation of union collective bargaining agreements
- If a merger would impact Wyoming outage reporting.

Appendix B

Load and Resource Balances

Table B-1 Cheyenne Light Load and Resource Balance – Base Load
Table B-2 BHP Load and Resource Balance – Base Load
Table B-3 Combined System Load and Resource Balance – Base Load
Table B-4 Cheyenne Light Load and Resource Balance – High Load
Table B-5 BHP Load and Resource Balance – High Load
Table B-6 Combined System Load and Resource Balance – High Load
Table B-7 Cheyenne Light Load and Resource Balance – Low Load
Table B-8 BHP Load and Resource Balance – Low Load
Table B-9 Combined System Load and Resource Balance – Low Load
Table B-10 Cheyenne Light Load and Resource Balance – Step Load
Table B-11 BHP Load and Resource Balance – Step Load
Table B-12 Combined System Load and Resource Balance – Step Load

Table B-1

Cheyenne Light, Fuel & Power Load and Resource Balance - Base Load																				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Peak Demand	219	222	226	229	233	236	240	243	247	251	254	258	262	266	270	274	278	282	287	291
DSM	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	216	219	223	226	230	233	237	240	244	248	251	255	259	263	267	271	275	279	284	288
15% reserve margin	32	33	33	34	35	35	36	36	37	37	38	38	39	39	40	41	41	42	43	43
Total Demand	248	252	256	260	265	268	273	276	281	285	289	293	298	302	307	312	316	321	326	331
(including planning reserve)																				
Resources																				
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
2014 CT	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2014 CC	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
2021 CT							36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2030 CT																36.8	36.8	36.8	36.8	36.8
Total Resources	165.8	165.8	165.8	165.8	165.8	165.8	202.6	202.6	202.6	202.6	202.6	202.6	202.6	202.6	202.6	239.4	239.4	239.4	239.4	239.4
Purchases																				
Wygen 1 PPA*	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
NSCT2 PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0	0	0	0	0
Silver Sage	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0
Market	25	50	50	50	50	50	25	25	25	25	25	50	50	50	50	25	25	25	50	50
Total Resources	253.3	278.3	278.3	278.3	278.3	278.3	290.1	290.1	290.1	290.1	290.1	315.1	315.1	315.1	313.6	324.4	324.4	324.4	349.4	349.4
Reserve Margin**	2.3%	12.1%	9.8%	8.1%	6.0%	4.4%	7.4%	5.9%	3.9%	2.0%	0.6%	8.6%	6.7%	4.8%	2.5%	4.7%	2.9%	1.2%	8.2%	6.4%

*Cheyenne Light has an option to convert the Wygen 1 PPA to utility ownership and has made the assumption that the PPA is replaced in kind

**Reserve margin calculation is in excess of assumed 15% planning reserve margin.

Source: Ventyx Advisors

Table B-2

Black Hills Power

Load and Resource Balance - Base Load

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand*	442	446	450	455	459	464	468	473	478	483	488	492	497	502	507	512.4	518	523	528	533
DSM	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	439	443	447	452	456	461	465	470	475	480	485	489	494	499	504	509	515	520	525	530
15% Reserve margin	66	66	67	68	68	69	70	71	71	72	73	73	74	75	76	76	77	78	79	80
Total Demand	505	509	514	520	524	530	535	541	546	552	558	562	568	574	580	586	592	598	604	610
(including planning reserves)																				
Resources																				
Ben French 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs 1-4	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2014 CC	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
2024 Coal										100	100	100	100	100	100	100	100	100	100	100
Total BHP Resources	457	457	457	457	457	457	457	457	457	557	557	557	557	557	557	557	557	557	557	557
Purchases																				
Colstrip	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0	0	0	0	0
Silver Sage	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0
Market	25	25	25	25	50	50	50	50	50	0	0	25	25	25	25	50	50	50	50	75
Sales																				
Sales (MEAN)	20	20	20	15	15	12	12	10	0	0	0	0	0	0	0	0	0	0	0	0
Total Resources	515.5	515.5	515.5	520.5	545.5	548.5	548.5	550.5	560.5	560.5	560.5	585.5	585.5	585.5	584.0	607.0	607.0	607.0	607.0	632.0
Reserve Margin***	2.4%	1.4%	0.3%	0.2%	4.6%	4.0%	3.0%	2.1%	3.0%	1.8%	0.6%	4.7%	3.5%	2.3%	0.9%	4.2%	2.9%	1.7%	0.6%	4.2%

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

Source: Ventyx Advisors

Table B-3

Combined System

Load and Resource Balance - Base Load

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand*	626	634	654	661	656	663	671	680	701	696	703	710	720	728	751	745	754	763	773	797
DSM	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
Net Peak Demand	620	628	648	655	650	657	665	674	695	690	697	704	714	722	745	739	748	757	767	791
15% Reserve margin	93	94	97	98	98	99	100	101	104	104	105	106	107	108	112	111	112	114	115	119
Total Demand	713	722	745	753	748	756	765	775	799	794	802	810	821	830	857	850	860	871	882	910
(including planning reserves)																				
Resources																				
Ben French 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs 1-4	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
2014 CT	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2014 CC (CLFP)	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
2014 CC (BHP)	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
2027 CT													36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2028 CT														36.8	36.8	36.8	36.8	36.8	36.8	36.8
2034 CT																				36.8
Total BHP Resources	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	659.6	696.4	696.4	696.4	696.4	696.4	696.4	733.2
Purchases																				
Colstrip	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0
Silver Sage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0
2024 Wind										3	3	3	3	3	3	3	3	3	3	3
Wygen 1 PPA*	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
NSCT2 PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Market	0	25	50	50	25	50	50	50	75	125	125	125	100	75	100	100	125	125	125	125
Sales																				
Sales (MEAN)	20	20	20	15	15	12	12	10	0	0	0	0	0	0	0	0	0	0	0	0
Total Resources	718.8	743.8	768.8	773.8	748.8	776.8	776.8	778.8	813.8	816.8	816.8	816.8	828.6	840.4	862.4	859.4	884.4	884.4	884.4	921.2
Reserve Margin* **	0.9%	3.4%	3.6%	3.1%	0.2%	3.2%	1.8%	0.5%	2.1%	3.4%	2.2%	1.0%	1.1%	1.4%	0.8%	1.3%	3.2%	1.8%	0.3%	1.5%

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

Source: Ventyx Advisors

Table B-4

Cheyenne Light, Fuel & Power Load and Resource Balance - High Load																				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Peak Demand	224	229	234	238	243	248	253	258	263	268	274	279	285	290	296	302	308	314	321	327
DSM	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	221	226	231	235	240	245	250	255	260	265	271	276	282	287	293	299	305	311	318	324
15% reserve margin	33	34	35	35	36	37	37	38	39	40	41	41	42	43	44	45	46	47	48	49
Total Demand	255	260	265	271	276	282	287	293	299	305	311	318	324	331	337	344	351	358	365	373
(including planning reserve)																				
Resources																				
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
2014 CT	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2014 CC	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
2019 CT					36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2026 CT												36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2031 CT																	36.8	36.8	36.8	36.8
Total Resources	165.8	165.8	165.8	165.8	202.6	202.6	202.6	202.6	202.6	202.6	202.6	239.4	239.4	239.4	239.4	239.4	276.2	276.2	276.2	276.2
Purchases																				
Wygen 1 PPA*	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
NSCT2 PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0	0	0	0	0
Silver Sage	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0
Market	50	50	50	50	25	25	25	50	50	50	50	25	25	50	50	50	25	25	50	50
Total Resources	278.3	278.3	278.3	278.3	290.1	290.1	290.1	315.1	315.1	315.1	315.1	326.9	326.9	351.9	350.4	349.4	361.2	361.2	386.2	386.2
Reserve Margin**	10.6%	8.2%	5.7%	3.3%	5.9%	3.5%	1.1%	8.6%	6.2%	3.8%	1.4%	3.4%	1.0%	7.4%	4.5%	1.8%	3.4%	1.0%	6.6%	4.2%

*Cheyenne Light has an option to convert the Wygen 1 PPA to utility ownership and has made the assumption that the PPA is replaced in kind

**Reserve margin calculation is in excess of assumed 15% planning reserve margin.

Source: Ventyx Advisors

Table B-5

Black Hills Power

Load and Resource Balance - High Load

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand*	458	466	474	482	490	499	508	517	526	535	544	554	563	573	583	594	604	615	625	636
DSM	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	455	463	471	479	487	496	505	514	523	532	541	551	560	570	580	591	601	612	622	633
15% Reserve margin	68	69	71	72	73	74	76	77	78	80	81	83	84	86	87	89	90	92	93	95
Total Demand	523	532	542	551	561	570	580	591	601	612	622	633	645	656	667	679	691	703	716	728
(including planning reserves)																				
Resources																				
Ben French 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs 1-4	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2014 CC	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
2017 CT			36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2024 Coal										100	100	100	100	100	100	100	100	100	100	100
2028 CT														36.8	36.8	36.8	36.8	36.8	36.8	36.8
2032 CT																		36.8	36.8	36.8
Total BHP Resources	457	457	493.8	493.8	493.8	493.8	493.8	493.8	493.8	593.8	593.8	593.8	593.8	630.6	630.6	630.6	630.6	667.4	667.4	667.4
Purchases																				
Colstrip	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0	0	0	0	0
Silver Sage	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0
Market	50	50	25	25	50	50	50	75	75	25	25	50	50	25	50	50	75	50	50	75
Sales																				
Sales (MEAN)	20	20	20	15	15	12	12	10	0	0	0	0	0	0	0	0	0	0	0	0
Total Resources	540.5	540.5	552.3	557.3	582.3	585.3	585.3	612.3	622.3	622.3	622.3	647.3	647.3	659.1	682.6	680.6	705.6	717.4	717.4	742.4
Reserve Margin* **	3.8%	1.7%	2.3%	1.3%	4.5%	3.0%	1.0%	4.2%	4.1%	2.0%	0.0%	2.5%	0.5%	0.6%	2.6%	0.2%	2.4%	2.3%	0.3%	2.2%

* Peak load includes 23MW COG and MDU Sheridan load

** Included COG's and MDU's ownership share

***Reserve margin calculation is in excess of assumed 15% planning reserve margin.

Source: Ventyx Advisors

Table B-6

Combined

Load and Resource Balance - High Load

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand*	640	655	685	696	693	704	716	730	764	760	775	785	799	813	849	849	864	875	891	931
DSM	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
Net Peak Demand	634	649	679	690	687	698	710	724	758	754	769	779	793	807	843	843	858	869	885	925
15% Reserve margin	95	97	102	104	103	105	107	109	114	113	115	117	119	121	126	126	129	130	133	139
Total Demand	730	746	781	794	790	803	817	833	872	867	884	896	912	928	970	970	986	999	1018	1063
(including planning reserves)																				
Resources																				
Ben French 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs 1-4	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
2014 CT	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2014 CC (CLFP)	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
2014 CC (BHP)	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
2023 CC									180	180	180	180	180	180	180	180	180	180	180	180
2030 Coal																100	100	100	100	100
Total BHP Resources	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	802.8	802.8	802.8	802.8	802.8	802.8	802.8	802.8	802.8	802.8	802.8	802.8
Purchases																				
Colstrip	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0
Silver Sage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0
2023 Wind									3	3	3	3	3	3	3	3	3	3	3	3
2031 Wind																	3	3	3	3
Wygen 1 PPA*	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
NSCT2 PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Market	25	50	75	75	75	100	100	125	0	25	50	50	75	100	125	25	50	75	75	125
Sales																				
Sales (MEAN)	20	20	20	15	15	12	12	10	0	0	0	0	0	0	0	0	0	0	0	0
Total Resources	743.8	768.8	793.8	798.8	798.8	826.8	826.8	853.8	921.8	896.8	921.8	921.8	946.8	971.8	993.8	890.8	918.8	943.8	943.8	993.8
Reserve Margin* **	2.2%	3.5%	1.9%	0.7%	1.2%	3.5%	1.4%	2.9%	6.6%	4.0%	4.9%	3.3%	4.5%	5.4%	2.9%	-9.3%	-7.9%	-6.4%	-8.3%	-7.5%

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

Source: Ventyx Advisors

Table B-7

Cheyenne Light, Fuel & Power Load and Resource Balance - Low Load	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand	214	216	218	220	223	225	227	229	232	234	236	239	241	243	246	248	251	253	256	258
DSM	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	211	213	215	217	220	222	224	226	229	231	233	236	238	240	243	245	248	250	253	255
15% reserve margin	32	32	32	33	33	33	34	34	34	35	35	35	36	36	36	37	37	38	38	38
Total Demand	243	245	248	250	253	255	258	260	263	266	268	271	274	277	279	282	285	288	291	294
(including planning reserve)																				
Resources																				
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
2014 CT	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2014 CC	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
2027 CT													36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
Total Resources	165.8	165.8	165.8	165.8	165.8	165.8	165.8	165.8	165.8	165.8	165.8	165.8	202.6	202.6	202.6	202.6	202.6	202.6	202.6	202.6
Purchases																				
Wygen 1 PPA*	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
NSCT2 PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0	0	0	0	0
Silver Sage	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0
Market	25	25	25	25	25	50	50	50	50	50	50	50	25	25	25	25	25	50	50	50
Total Resources	253.3	253.3	253.3	253.3	253.3	278.3	278.3	278.3	278.3	278.3	278.3	278.3	290.1	290.1	288.6	287.6	287.6	312.6	312.6	312.6
Reserve Margin**	5.1%	3.9%	2.7%	1.5%	0.3%	10.4%	9.2%	7.9%	6.7%	5.5%	4.3%	3.1%	6.9%	5.6%	3.8%	2.2%	1.0%	9.9%	8.6%	7.4%

*Cheyenne Light has an option to convert the Wygen 1 PPA to utility ownership and has made the assumption that the PPA is replaced in kind
**Reserve margin calculation is in excess of assumed 15% planning reserve margin.

Source: Ventyx Advisors

Table B-8

Black Hills Power

Load and Resource Balance - Low Load

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand*	426	427	428	429	430	431	432	433	434	435	436	438	439	440	441	442	443	444	445	446
DSM	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	423	424	425	426	427	428	429	430	431	432	433	435	436	437	438	439	440	441	442	443
15% Reserve margin	63	64	64	64	64	64	64	65	65	65	65	65	65	66	66	66	66	66	66	67
Total Demand	487	488	489	490	491	492	493	495	496	497	498	500	501	502	504	505	506	507	509	510
(including planning reserves)																				
Resources																				
Ben French 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs 1-4	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2014 CC	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
2031 CT																	36.8	36.8	36.8	36.8
Total BHP Resources	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	493.8	493.8	493.8	493.8
Purchases																				
Colstrip	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0	0	0	0	0
Silver Sage	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0
Market	0	0	0	0	0	0	0	0	0	50	50	50	50	50	50	50	25	25	25	25
Sales																				
Sales (MEAN)	20	20	20	15	15	12	12	10	0	0	0	0	0	0	0	0	0	0	0	0
Total Resources	490.5	490.5	490.5	495.5	495.5	498.5	498.5	500.5	510.5	510.5	510.5	510.5	510.5	510.5	509.0	507.0	518.8	518.8	518.8	518.8
Reserve Margin***	0.9%	0.6%	0.4%	1.3%	1.1%	1.5%	1.2%	1.3%	3.4%	3.1%	2.8%	2.5%	2.2%	1.9%	1.3%	0.5%	2.9%	2.6%	2.3%	2.0%

* Peak load includes 23MW COG and MDU Sheridan load

** Included COG's and MDU's ownership share

***Reserve margin calculation is in excess of assumed 15% planning reserve margin.

Source: Ventyx Advisors

Table B-9

Combined Load and Resource Balance - Low Load	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand*	602	606	624	626	619	617	620	624	644	633	636	638	640	644	664	654	658	655	659	680
DSM	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
Net Peak Demand	596	600	618	620	613	611	614	618	638	627	630	632	634	638	658	648	652	649	653	674
15% Reserve margin	89	90	93	93	92	92	92	93	96	94	95	95	95	96	99	97	98	97	98	101
Total Demand	685	690	711	713	705	703	706	711	734	722	725	726	729	733	757	745	750	747	751	775
(including planning reserves)																				
Resources																				
Ben French 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs 1-4	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
2014 CT	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2014 CC (CLFP)	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
2014 CC (BHP)	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Total BHP Resources	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8	622.8
Purchases																				
Colstrip	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0
Silver Sage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0
2028 Wind														3	3	3	3	3	3	3
Wygen 1 PPA*	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
NSCT2 PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Market	0	0	0	0	0	0	0	0	0	50	50	50	50	50	75	75	75	75	75	100
Sales																				
Sales (MEAN)	20	20	20	15	15	12	12	10	0	0	0	0	0	0	0	0	0	0	0	0
Total Resources	718.8	718.8	718.8	723.8	723.8	726.8	726.8	728.8	738.8	738.8	738.8	738.8	738.8	741.8	763.8	760.8	760.8	760.8	760.8	785.8
Reserve Margin* **	5.6%	4.9%	1.2%	1.7%	3.0%	4.0%	3.4%	2.9%	0.8%	2.7%	2.3%	2.0%	1.5%	1.3%	1.1%	2.5%	1.7%	2.2%	1.6%	1.6%

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

Source: Ventyx Advisors

Table B-10

Cheyenne Light, Fuel & Power

Load and Resource Balance - Step Load

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand	270	274	278	282	286	291	295	300	304	309	313	318	323	328	332	337	343	348	353	358
DSM	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	267	271	275	279	283	288	292	297	301	306	310	315	320	325	329	334	340	345	350	355
15% reserve margin	40	41	41	42	43	43	44	44	45	46	47	47	48	49	49	50	51	52	52	53
Total Demand	307	312	316	321	326	331	336	341	346	351	357	362	368	373	379	385	390	396	402	408
(including planning reserve)																				
Resources																				
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
2014 CT	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2014 CC	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
2015 CT	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2017 CT			36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2024 Coal										100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total Resources	202.6	202.6	239.4	239.4	239.4	239.4	239.4	239.4	239.4	339.4	339.4	339.4	339.4	339.4	339.4	339.4	339.4	339.4	339.4	339.4
Purchases																				
Wygen 1 PPA*	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
NSCT2 PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0	0	0	0	0
Silver Sage	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0
Market	50	50	25	25	25	50	50	50	50	0	0	0	0	0	0	0	0	0	25	25
Total Resources	315.1	315.1	326.9	326.9	326.9	351.9	351.9	351.9	351.9	401.9	401.9	401.9	401.9	401.9	400.4	399.4	399.4	399.4	424.4	424.4
Reserve Margin**	3.1%	1.3%	3.8%	2.1%	0.3%	7.3%	5.5%	3.7%	1.9%	16.5%	14.5%	12.6%	10.7%	8.8%	6.5%	4.4%	2.6%	0.9%	6.3%	4.5%

*Cheyenne Light has an option to convert the Wygen 1 PPA to utility ownership and has made the assumption that the PPA is replaced in kind

**Reserve margin calculation is in excess of assumed 15% planning reserve margin.

Source: Ventyx Advisors

Table B-11

Black Hills Power

Load and Resource Balance - Step Load

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand*	482	486	491	496	501	506	511	516	521	526	532	537	542	548	553	559	564	570	576	582
DSM	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	479	483	488	493	498	503	508	513	518	523	529	534	539	545	550	556	561	567	573	579
15% Reserve margin	72	72	73	74	75	75	76	77	78	79	79	80	81	82	83	83	84	85	86	87
Total Demand	550	556	561	567	573	578	584	590	596	602	608	614	620	627	633	639	646	652	659	665
(including planning reserves)																				
Resources																				
Ben French 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs 1-4	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2014 CC	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
2015 CT	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2024 Coal										100	100	100	100	100	100	100	100	100	100	100
2032 CT																		36.8	36.8	36.8
Total BHP Resources	493.8	493.8	493.8	493.8	493.8	493.8	493.8	493.8	493.8	593.8	593.8	593.8	593.8	593.8	593.8	593.8	593.8	630.6	630.6	630.6
Purchases																				
Colstrip	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0	0	0	0	0
Silver Sage	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0
Market	25	50	50	50	50	50	50	75	50	25	25	25	25	50	50	50	75	25	50	50
Sales																				
Sales (MEAN)	20	20	20	15	15	12	12	10	0	0	0	0	0	0	0	0	0	0	0	0
Total Resources	552.3	577.3	577.3	582.3	582.3	585.3	585.3	612.3	597.3	622.3	622.3	622.3	622.3	647.3	645.8	643.8	668.8	655.6	680.6	680.6
Reserve Margin***	0.4%	4.5%	3.4%	3.0%	2.0%	1.4%	0.2%	4.3%	0.3%	3.9%	2.7%	1.5%	0.4%	3.8%	2.4%	0.8%	4.1%	0.6%	3.8%	2.6%

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

Source: Ventyx Advisors

Table B-12

Combined

Load and Resource Balance - Step Load

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand*	708	717	746	752	747	752	760	769	800	794	803	807	816	826	857	852	862	866	876	911
DSM	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
Net Peak Demand	702	711	740	746	741	746	754	763	794	788	797	801	810	820	851	846	856	860	870	905
15% Reserve margin	105	107	111	112	111	112	113	114	119	118	120	120	121	123	128	127	128	129	131	136
Total Demand	808	817	851	858	853	858	867	878	913	906	916	921	931	943	979	972	984	989	1001	1041
(including planning reserves)																				
Resources																				
Ben French 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs 1-4	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
2014 CT	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
2014 CC (CLFP)	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
2014 CC (BHP)	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
2017 CT			36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
2023 CT									180	180	180	180	180	180	180	180	180	180	180	180
2029 Coal															100	100	100	100	100	100
Total BHP Resources	622.8	622.8	659.6	659.6	659.6	659.6	659.6	659.6	839.6	839.6	839.6	839.6	839.6	839.6	939.6	939.6	939.6	939.6	939.6	939.6
Purchases																				
Colstrip	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0
Silver Sage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0
2022 Wind								3	3	3	3	3	3	3	3	3	3	3	3	3
2030 Wind																3	3	3	3	3
Wygen I PPA*	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
NSCT2 PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Market	100	100	100	100	100	100	125	125	0	25	50	50	50	75	0	0	0	25	25	75
Sales																				
Sales (MEAN)	20	20	20	15	15	12	12	10	0	0	0	0	0	0	0	0	0	0	0	0
Total Resources	818.8	818.8	855.6	860.6	860.6	863.6	888.6	893.6	958.6	933.6	958.6	958.6	958.6	983.6	1005.6	1005.6	1005.6	1030.6	1030.6	1080.6
Reserve Margin***	1.6%	0.2%	0.6%	0.3%	1.1%	0.7%	2.9%	2.1%	5.8%	3.5%	5.3%	4.7%	3.4%	4.9%	3.2%	3.9%	2.5%	4.8%	3.4%	4.4%

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

Source: Ventyx Advisors

Black Hills Power and Cheyenne Light Fuel and Power Generation Pool Study

Volume II – Generation Pool Modeling Assumptions Report

September 30, 2013

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Appendices

List of Tables

This report details the assumptions that were used to complete capacity expansion and production cost modeling for the Black Hills Power (BHP) and Cheyenne Light Fuel and Power (Cheyenne Light) Generation Pool Study. BHP and Cheyenne Light both completed Integrated Resource Plans (IRPs) in 2011 that were filed with the Wyoming Public Service Commission (WPSC) in support of a Certificate of Public Convenience and Necessity (CPCN) for the addition of generation resources to meet anticipated peak and energy growth in Cheyenne Light's and Black Hills Power's service territories. Many of the assumptions that were used in the two IRPs were also used in the Generation Pool Study such as each utility's load forecast, planning reserve requirement, financial assumptions, contract pricing and existing unit performance parameters. Some assumptions were updated to more recent forecasts such as the natural gas price and electric price forecasts. The following sections provide further detail regarding the assumptions that were used in the Generation Pool Study.

1. Planning Period

A twenty-year planning period was used for the Generation Pool Study. This covers the period 2015-2034.

2. Load Forecast

2.1. Methodology

BHP and CLFP both completed Integrated Resource Plans (IRPs) in 2011 that were filed with the Wyoming Public Service Commission (WPSC) in support of a Certificate of Public Convenience and Necessity (CPCN) for the addition of generation resources to meet anticipated peak and energy growth in Cheyenne Light's and Black Hills Power's service territories. The load forecasts from these plans will be extended to 2034 and used as the load forecast for the Generation Pool. The IRPs used the annual growth rates for peak and energy shown in the table below then annual anticipated large customer load additions were added to each year's base forecast.

2.2. Growth Rates

The following growth rates were used in the Generation Pool Study and the 2011 IRPs.

Table 2-1
BHP and Cheyenne Light Growth Rates

Utility	Peak (%)	Energy (%)
BHP	1.0	1.0
CLFP	1.5	1.5

2.3. Large Customer Projections

Energy Services representatives provided data from large customers that have indicated potential load growth in the next five years. This information includes the MW increase expected per year, the level of confidence that the load addition will actually materialize (confidence interval, CI) and the expected load factor of the load addition. The confidence interval is an indication of the level of certainty that the load addition will actually materialize. The higher the confidence factor the more certain the load will be added. The large customer projections shown below were used in both the Generation Pool Study and the 2011 IRPs.

Table 2-2
CLFP Large Customer Projections – included in 2011 IRP

Customer	2012		2013		2014		2015		2016		2017		Load Factor
	MW	CI	MW	CI	MW	CI	MW	CI	MW	CI	MW	CI	
Customer A	3.6				2.4								0.90
Customer B	5.6												0.70
Customer C	3.2				2.8								0.90
Customer D	1.05												0.70
Customer E	2.25												0.75
Customer F			2.8										0.70
Customer G			1.05										0.90
Customer H			3.5										0.90

Table 2-3
BHP Large Customer Projections – included in 2011 IRP

Customer	2012		2013		2014		2015		2016		2017		Load Factor
	MW	CI	MW	CI	MW	CI	MW	CI	MW	CI	MW	CI	
Customer A			8.05				4.6						0.85
Customer B					.15								0.70
Customer C							2.0						0.50

2.4. DSM Adjustment

A DSM Adjustment was included in Cheyenne Light's load forecast based on the DSM savings forecast approved by the Wyoming Public Service Commission in Docket 20003-108-EA-10.

Table 2-4
2015 DSM Adjustment

	Peak (MW)	Energy (MWh)
BHP	3.294	13,388
Cheyenne Light	2.911	18,252

2.5. Additional Loads

The City of Gillette's 23 MW and MDU's 25 MW ownership share of Wygen III are reflected as loads in the load forecast. BHP is contractually obligated to provide an equivalent amount of capacity and energy from its other generating facilities to Gillette and MDU when Wygen III is off-line for scheduled or forced outages.

In addition BHP has a contract with MDU to serve the remainder of the City of Sheridan's load. Though this contract expires on Dec. 31, 2016, it was assumed that the contract would be extended through the study planning period.

3. Planning Reserve Margin

For purposes of this Generation Pool Study, the Company has assumed a minimum planning reserve margin of 15%.

The tables below show the monthly load forecast, peaks and energy for BHP and Cheyenne Light.

Table 3-1
BHP Peak Demand and Energy Forecast 2015-2034
(Includes Gillette and Sheridan loads)

Year	Peak Demand (MW)	Growth in Peak Demand (%)	Annual Energy (MWh)	Growth in Annual Energy (%)	Load Factor (%)
2015	442	2.72	2,465,252	2.20	64.0
2016	446	0.94	2,504,224	1.58	64.1
2017	450	0.93	2,529,276	1.00	64.2
2018	455	1.14	2,554,576	1.00	64.1
2019	459	0.91	2,580,134	1.00	64.1
2020	464	1.00	2,605,935	1.00	64.1
2021	468	1.00	2,631,995	1.00	64.1
2022	473	1.00	2,658,315	1.00	64.1
2023	478	1.00	2,684,898	1.00	64.1
2024	483	1.00	2,711,747	1.00	64.1
2025	488	1.00	2,738,864	1.00	64.1
2026	492	1.00	2,766,253	1.00	64.1
2027	497	1.00	2,793,915	1.00	64.1
2028	502	1.00	2,821,855	1.00	64.1
2029	507	1.00	2,850,073	1.00	64.1
2030	512	1.00	2,878,574	1.00	64.1
2031	518	1.00	2,907,360	1.00	64.1
2032	523	1.00	2,936,433	1.00	64.1
2033	528	1.00	2,965,798	1.00	64.1
2034	533	1.00	2,995,456	1.00	64.1

Table 3-2
Cheyenne Light Peak Demand and Energy Forecast 2015-2034

Year	Peak Demand (MW)	Growth in Peak Demand (%)	Annual Energy (MWh)	Growth in Annual Energy (%)	Load Factor (%)
2015	219	1.5	1,416,928	1.5	73.8
2016	222	1.5	1,438,180	1.5	73.8
2017	226	1.5	1,459,755	1.5	73.8
2018	229	1.5	1,481,651	1.5	73.8
2019	233	1.5	1,503,874	1.5	73.8
2020	236	1.5	1,526,432	1.5	73.8
2021	240	1.5	1,549,328	1.5	73.8
2022	243	1.5	1,572,568	1.5	73.8
2023	247	1.5	1,596,157	1.5	73.8
2024	251	1.5	1,620,099	1.5	73.8
2025	254	1.5	1,644,401	1.5	73.8
2026	258	1.5	1,669,067	1.5	73.8
2027	262	1.5	1,694,103	1.5	73.8
2028	266	1.5	1,719,514	1.5	73.8
2029	270	1.5	1,745,307	1.5	73.8
2030	274	1.5	1,771,487	1.5	73.8
2031	278	1.5	1,798,059	1.5	73.8
2032	282	1.5	1,825,030	1.5	73.8
2033	287	1.5	1,852,405	1.5	73.8
2034	291	1.5	1,880,191	1.5	73.8

4. Load and Resource Balance

A load and resource balance is used to compare annual peak demand with the annual capability of existing resources. The load and resource balance highlights the year in which forecast load exceeds resources and indicates a need for additional generation. The load and resource balance takes into account the planning reserve requirement.

The following assumptions were included in the load and resource balance for the Generation Pool Study.

- Ben French Steam Unit is retired beginning January 1, 2013
- Neil Simpson 1 is retired December 31, 2013
- Cheyenne Prairie Generation Station comes on-line October 1, 2014

Appendix A of this report includes tables that show annual load and resource balances for BHP's and Cheyenne Light's IRP Preferred Plan the years 2015 through 2034 for each of the utilities.

5. Existing Resources

5.1. Station Data

Station Data – Black Hills Power and Cheyenne Light consider this unit level data confidential and proprietary information and does not allow the distribution of this data without express written approval. During the course of this study stakeholders that signed confidentiality agreements were provided the unit level data.

6. Spinning Reserve Requirement Assumption

6.1. BHP

- NS II carries spin - 8 MW through October 2014
- Beginning October 2014 spin requirement increases to 13 MW

6.2. Cheyenne Light

- 2012 - 2014 –Wygen II carries 12 MW spin

7. Fuel Price Assumptions

Fuel Price Forecasts –Black Hills Power and Cheyenne Light used monthly fuel price forecasts that were developed by Ventyx Advisors for the Generation Pool Study modeling. Ventyx considers these forecast confidential and proprietary information and does not allow the distribution of these forecasts without express written approval. During the course of this study stakeholders that signed confidentiality agreements were provided the fuel price forecasts.

7.1. Coal

7.1.1. BHP, CLFP and BH Wyoming

- Coal prices are internally generated values based on operating costs of the Wyodak Coal Mine.
- Future year escalation rate base on Ventyx' Fall 2012 Reference Case coal assumptions for the Northern PRB producing region.

7.2. Natural Gas

7.2.1. BHP, Cheyenne Light and BH Wyoming

- Used Ventyx's Fall 2012 Reference Case Natural Gas Price forecast for Henry Hub. The Henry Hub value was adjusted for transportation costs to reflect the price of natural gas as delivered to Cheyenne Light and BHP.
- Commodity price was adjusted to include 6% sales tax for fuel delivered in Rapid City (used for Ben French CTs and Lange CTs).

7.3. Diesel Fuel

Used Ventyx's 2012 Fall Reference Case for the cost of diesel fuel for BHP's diesel units.

8. Emission Costs

Emission costs were not included in the BHP or Cheyenne Light models.

9. Contracts

9.1. BHP Contracts

9.1.1. Pacificorp PPA (Colstrip)

- 50 MW of coal-fired base load power
- Monthly minimum energy purchase (22,500 MWh*50 MW)/75 MW=15,000
- Expires December 31, 2023
- Includes the following contract pricing components:
  - Annual fixed cost multiplied by the capacity purchased
  - Fixed Charge is eliminated in 2019
  - Adjusted variable cost payment ($/MWh)

9.1.2. MEAN Sales Contracts

- BHP supplies 20 MW of unit contingent capacity and energy to MEAN
  - Based on availability of Neil Simpson II and Wygen III with decreasing capacity purchase over the term of the contract
    - 2012-2017 – 20 MW; 10 MW contingent on Wygen III and 10 MW on NS II
    - 2018-2019 – 15 MW; 10 MW contingent on Wygen III and 5 MW on NS II
    - 2020-2021 – 12 MW; 6 MW contingent on Wygen III and 6 MW on NS II
    - 2022-2023 – 10 MW; 5 MW contingent on Wygen III and 5 MW on NS II
  - Expires May 31, 2023

- BHP supplies 10 MW of unit contingent capacity and energy to MEAN
  - 5 MW from Wygen III and 5 MW from NS II
  - Expires May 31, 2015

- Pricing for both contracts is based on the following:
  - Fixed cost segment $/MWh
  - Governmental impositions for capital expenditures
  - Variable cost segment
    - Actual percentage increase in fuel and variable operating expense, including labor of the Wygen I plant

9.1.3. Cheyenne Light PUT

Cheyenne Light and BHP's Generation Dispatch Agreement requires BHP to purchase all of Cheyenne Light's excess energy. This was modeled as a load reduction to BHP's load forecast.

9.1.4. Happy Jack Wind PPA

- Happy Jack Station capacity 14.7 MW (29.4 MW total, 50% to BHP, 50% to CLFP)
- 20 year PPA
- Happy Jack Contract Price beginning 9/2008; Price increases each year on anniversary date by 1.5%
- Contract expires August 31, 2028

9.1.5. Silver Sage PPA

- Silver Sage capacity 20 MW (30 MW total, 66.7% to BHP, 33.3% to CLFP)
- 20 year PPA
- Silver Sage Contract Price beginning 9/2009; Price increases each year on anniversary data by 2.5%
- Contract expires September 30, 2029

9.2. Cheyenne Light Contracts

9.2.1. Wygen 1 PPA (BH Wyoming)

- PPA for 60 MW of unit contingent capacity and energy
- Assumed that this contract expires December 31, 2034
- Contract price for remaining years of planning period escalated between 2.17% and 2.2%

9.2.2. Happy Jack Wind PPA

- Happy Jack Station capacity 14.7 MW (29.4 MW total, 50% to BHP, 50% to CLFP)
- 20 year PPA
- Happy Jack Contract Price beginning 9/2008; Price increases each year on anniversary date by 1.5%
- Contract expires August 31, 2028

9.2.3. Silver Sage PPA

- Silver Sage capacity 10 MW (30 MW total, 66.7% to BHP, 33.3% to CLFP)
- 20 year PPA
- Silver Sage Contract Price beginning 9/2009; Price increases each year on anniversary data by 2.5%
- Contract expires September 30, 2029

10. Economy Energy Purchases

Electric Price Forecasts –Black Hills Power and Cheyenne Light used monthly electric price forecasts that were developed by Ventyx Advisors for the Generation Pool Study modeling. Ventyx considers these forecast confidential and proprietary information and does not allow the distribution of these forecasts without express written approval. During the course of this study stakeholders that signed confidentiality agreements were provided the electric price forecasts.

10.1. BHP Economy Energy Purchase Assumptions

- Allowed to purchase up to 500 MW
- Used Ventyx's 2012 Fall Reference Case WY and AZ-PV Market Area forecasts for pricing

10.2. Cheyenne Light Economy Energy Purchase Assumptions

- Allowed to purchase up to 150 MW
- Used Ventyx's 2012 Fall Reference Case WY and AZ-PV Market Area forecasts for pricing

10.3. Seasonal Capacity Purchases

10.3.1. BHP Seasonal Capacity Purchases

- Capacity Purchases for July and August, months when a capacity deficit is expected based on Load and Resource Balance (6 days per week, 16 hours per day)
- Price for 2015 through 2034 based on Ventyx's 2012 Fall Reference Case AZ-PV market price forecast plus 10% premium

10.3.2. CLFP Seasonal Capacity Purchases

- Capacity Purchases for July and August, months when a capacity deficit is expected based on Load and Resource Balance (6 days per week, 16 hours per day)
- Price based on Ventyx's WECC Fall 2012 Reference Case AZ-PV market plus 10%

11. Electric Price Assumptions

Electric Price Forecasts – For the Generation Pool Study modeling Black Hills Power and Cheyenne Light used monthly electric price forecasts that were developed by Ventyx Advisors. Ventyx considers these forecast confidential and proprietary information and does not allow the distribution of these forecasts without express written approval. During the course of this study stakeholders that signed confidentiality agreements were provided the fuel and electric price forecasts.

12. Financial Parameters

The financial parameters used in this Generation Pool Study are summarized in the table below.

Table 12-1
Financial Parameters

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

13. New Conventional Resources

A variety of conventional supply-side resources were examined and considered in preparing this Generation Pool Study. These include coal, different configurations of natural gas-fired combined cycle, and several types of natural gas-fired simple cycle combustion turbines. The performance parameters of the supply-side resources that were available for selection in the capacity expansion modeling are included in the tables below.

Table 13-1
Coal-Fired Power Plant Performance Parameters

Parameter	Value
Size, MW (net) – summer	100
Full load heat rate, Btu/kWh	11,500
SO_2 Emission Rate, lb/MMBtu	0.03
NO_x Emission Rate, lb/MMBtu	0.05
CO_2 Emission Rate, lb/MMBtu	210
Fixed O&M, $/kW-year (2015 $)	30.49
Variable O&M, $/MWh (2015 $)	4.53
Forced Outage Rate, %	2.00
Maintenance Outage Rate, %	2.00
Capital Cost, $/kW (2015 $)	2,972

Table 13-2
Combined Cycle Combustion Turbine Power Plant Performance Parameters

Parameter	NS CT Conv to CC – Air/Water	CC Conversion	1 x 1 with Duct Firing	2 x 1	3 x 1
Size, MW (net) – summer	45/55	55	55.7	91.8	137.4
Full load heat rate, Btu/kWh	7,947/7,547	7,947	8,168	7,547	7,562
SO_2 Emission Rate, lb/MMBtu	0.00	0.00	0.00	0.00	0.00
NO_x Emission Rate, lb/MMBtu	0.009	0.009	0.01	0.01	0.01
CO_2 Emission Rate, lb/MMBtu	120	120	117	120	120
Fixed O&M, $/kW-year (2015 $)	14.71	14.71	14.71	14.71	14.71
Variable O&M, $/MWh (2015 $)	2.43	2.43	2.43	2.43	2.43
Forced Outage Rate, %	2.00	2.00	2.00	2.00	2.00
Maintenance Outage Rate, %	2.00	2.00	2.00	2.00	2.00
Capital Cost, $/kW (2015 $)	1,867	1,471	1,615	1,552	1,334
Notes: 1x1 with Duct Firing reflects one combustion turbine and one steam generator 2x1 reflects two combustion turbines feeding one steam generator 3x1 reflects three combustion turbines feeding one steam generator CC conversion represent the incremental net capacity addition of converting a simple cycle to a combined cycle.					

Table 13-3
Simple Cycle Combustion Turbine Power Plant Performance Parameters

Parameter	Small CT	Aeroderivative CT
Size, MW (net) – summer	36.2	90
Full load heat rate, Btu/kWh	9,566	9,000
SO_2 Emission Rate, lb/MMBtu	0.00	0.00
NO_x Emission Rate, lb/MMBtu	0.01	0.03
CO_2 Emission Rate, lb/MMBtu	120	120
Fixed O&M, $/kW-year (2015 $)	12.39	12.39
Variable O&M, $/MWh (2015 $)	3.73	3.73
Forced Outage Rate, %	2.00	3.60
Maintenance Outage Rate, %	2.00	4.10
Capital Cost, $/kW (2015 $)	1,150	1,154

Table 13-4
PV Performance Parameters

Parameter	Value
Size, MW (net) – summer	10
Full load heat rate, Btu/kWh	N/A
SO_2 Emission Rate, lb/MMBtu	N/A
NO_x Emission Rate, lb/MMBtu	N/A
CO_2 Emission Rate, lb/MMBtu	N/A
Fixed O&M, $/kW-year (2015 $)	14.20
Variable O&M, $/MWh (2015 $)	0.00
Forced Outage Rate, %	0.00
Maintenance Outage Rate, %	0.00
Capital Cost, $/kW (2015 $)	6,902

Table 13-5
Wind Performance Parameters

Parameter	Value
Size, MW (net) – summer and winter	30
Fixed O&M, $/kW-year (2015 $)	33.43
Capital Cost, $/kW (2015 $)	1,731

Appendix A – Annual Load and Resource Balances

Black Hills Power
Load and Resource Balance - Preferred Plan

1.01

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand*	408	414	426	430	442	446	450	455	459	464	468	473	478	483	488	492	497	502	507	512	518	523	528	533
DSM	0	(1)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	408	413	424	427	439	443	447	452	456	461	465	470	475	480	485	489	494	499	504	509	515	520	525	530
15% Reserve margin	61	62	64	64	66	66	67	68	68	69	70	71	71	72	73	73	74	75	76	76	77	78	79	80
Total Demand	469	475	488	491	505	509	514	520	524	530	535	541	546	552	558	562	568	574	580	586	592	598	604	610
(including planning reserves)																								
Resources																								
Ben French 1	22	22	22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson I	16	16	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs 1-4	100	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Combined Cycle Conversion				55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
New Coal														100	100	100	100	100	100	100	100	100	100	100
New Combustion Turbine																				36	36	36	36	36
Total BHP Resources	468	440	440	457	457	457	457	457	457	457	457	457	457	557	557	557	557	557	557	593	593	593	593	593
Purchases																								
Colstrip	50	50	50	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0	0	0	0	0
Silver Sage	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0
Capacity	0	25	25	25	25	25	50	50	50	50	50	50	50	0	0	25	25	25	25	0	0	0	0	0
Sales																								
Sales (MEAN)	30	30	30	30	20	20	20	15	15	12	12	10	10	0	0	0	0	0	0	0	0	0	0	0
Total Resources	491.5	488.5	488.5	505.5	515.5	515.5	540.5	545.5	545.5	548.5	548.5	550.5	550.5	560.5	560.5	585.5	585.5	585.5	584.0	593.0	593.0	593.0	593.0	593.0
Reserve Margin***	5.5%	3.3%	0.2%	3.4%	2.4%	1.4%	5.9%	5.7%	4.6%	4.0%	3.0%	2.1%	0.9%	1.8%	0.6%	4.7%	3.5%	2.3%	0.9%	1.4%	0.3%	-0.9%	-2.0%	-3.2%

Cheyenne Light, Fuel & Power

Load and Resource Balance - Preferred Plan

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Peak Demand	180	197	208	216	219	222	226	229	233	236	240	243	247	251	254	258	262	266	270	274	278	282	287	291
DSM	(1)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	179	195	205	213	216	219	223	226	230	233	237	240	244	248	251	255	259	263	267	271	275	279	284	288
15% reserve margin	27	29	31	32	32	33	33	34	35	35	36	36	37	37	38	38	39	39	40	41	41	42	43	43
Total Demand	206	224	236	245	248	252	256	260	265	268	273	276	281	285	289	293	298	302	307	312	316	321	326	331
(Including planning reserve)																								
Resources																								
Wygen II	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
2014 CT 1	0	0	0	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2
2014 30 MW CC	0	0	0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
2023 CT 2													36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2
2030 CT 3																				36.2	36.2	36.2	36.2	36.2
2030 CT 4																				36.2	36.2	36.2	36.2	36.2
Total Resources	90.0	90.0	90.0	165.2	165.2	165.2	165.2	165.2	165.2	165.2	165.2	165.2	201.4	201.4	201.4	201.4	201.4	201.4	201.4	273.8	273.8	273.8	273.8	273.8
Purchases																								
Wygen 1 PPA*	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
NSCT2 PPA	40	40	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0	0	0	0	0
Silver Sage	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0
Market	25	50	50	0	25	50	50	50	50	50	50	50	25	25	50	50	50	50	50	0	0	0	0	0
Total Resources	217.5	242.5	242.5	267.7	252.7	277.7	277.7	277.7	277.7	277.7	277.7	277.7	288.9	288.9	313.9	313.9	313.9	313.9	312.4	333.8	333.8	333.8	333.8	333.8
Reserve Margin**	5.7%	8.1%	2.9%	9.3%	1.7%	10.3%	8.3%	6.8%	5.0%	3.6%	1.9%	0.6%	3.0%	1.3%	8.7%	7.0%	5.4%	3.8%	1.7%	7.1%	5.5%	3.9%	2.4%	0.9%

*Cheyenne Light has an option to convert the Wygen 1 PPA to utility ownership and has made the assumption that the PPA is replaced in kind

**Reserve margin calculation is in excess of assumed 15% planning reserve margin.

Black Hills Power and Cheyenne Light Fuel and Power Generation Pool Study

Volume III – Stakeholder Meetings and Education

September 30, 2013

Stakeholder Meetings and Education

1. Agenda for Stakeholder Meeting September 27-28, 2012
2. BHP/CLFP Generation Fleet Powerpoint Presentation for September 27, 2012 Stakeholder Meeting
3. Meeting Notes for September 27-28, 2012 Stakeholder Meeting
4. Agenda for Stakeholder Meeting November 15, 2012
5. BHP/CLFP Transmission Powerpoint Presentation for November 15, 2012 Stakeholder Meeting
6. Meeting Notes for November 15, 2012 Stakeholder Meeting
7. Outline for Environmental Issues Impacting Generation meeting December 3, 2012
8. Meeting Notes for December 3, 2012 Stakeholder Meeting
9. Agenda for December 5-6, 2012 Stakeholder Meeting
10. Generation Dispatch and Power Marketing Powerpoint Presentation for December 5, 2012 Stakeholder Meeting
11. Generation Pool Modeling Powerpoint Presentation for December 6, 2012 stakeholder meeting
12. Meeting Notes for December 5-6, 2012 Stakeholder Meeting
13. Agenda for May 30, 2013 Stakeholder Meeting
14. Generation Pool Modeling Powerpoint presentation for May 30, 2013 Stakeholder Meeting
15. Meeting Notes, May 30, 2013 Stakeholder Meeting
16. Agenda for July 2, 2013 Stakeholder Meeting
17. Powerpoint Presentation for July 2, 2013 Stakeholder Meeting
18. Meeting Notes for July 2, 2013 Stakeholder Meeting
19. Powerpoint Presentation for July 31, 2013 Stakeholder Meeting
20. Meeting Notes for July 31, 2013 Stakeholder Meeting
21. Powerpoint Presentation for August 20, 2013 Stakeholder Meeting
22. Meeting Notes for August 20, 2013 Stakeholder Meeting
23. Agenda, August 26, 2013 Stakeholder Meeting
24. Meeting Notes for August 26, 2013 Stakeholder Meeting
25. Meeting Notes for September 3, 2013 Stakeholder Meeting
26. Meeting Notes for September 20, 2013 Stakeholder Meeting

Meeting Agenda – September 27 and 28, 2012

Where: Administration Building at BHC Gillette Energy Complex

Thursday, September 27, 2012, 3:00 pm

3:00 p.m.	Introductions	Kyle White
	Brief History	Kyle White
	Power Generation (existing and planned)	Greg Hagar
	Generation Dispatch Agreements	Andy Butcher
5:00 p.m.	Adjourn	
6:30 p.m.	Group Dinner (location TBD)	

Friday, September 28, 2012

8:00 a.m.	Study Scoping Session (possible topics)	All
	Set objectives	
	Define final work product	
	Set participant expectations	
	Define work (steps, priorities, timing)	
	Communications (frequency of meetings, calls, etc.)	
10:45 a.m.	Final Comments	
11:00 a.m.	Adjourn	

Generation Pool Study Background

Since the acquisition of Cheyenne Light, Fuel and Power Company by Black Hills Corporation in 2005 various levels of joint operations and resource planning between Cheyenne Light and Black Hills Power have occurred. Most recently the utilities jointly applied for and received a CPCN from the Wyoming Public Service Commission to construct jointly-owned generation in Cheyenne, Wyoming. The Commission approved stipulation and agreement with the Wyoming Office of Consumer Advocate included the following provision:

"1. Black Hills Power And Cheyenne Light Generation Pool Study. The Parties acknowledge that the Utilities own and operate affiliated vertically integrated electric utility systems and that these systems have both similar and unique operating characteristics. The Applicants have made efforts to achieve efficiencies through both joint and centralized efforts, and have at times considered whether there would be advantages to customers from a jointly-owned and operated generation pool that combines their respective power supply resources and capabilities. The Parties agree that with the construction of the Cheyenne Prairie Generating Station it is an appropriate time to seriously evaluate the potential costs and benefits of a combined generation pool for the Utilities. The potential benefits of such a pool arrangement could include among other things, more efficient and comprehensive resource planning and acquisition and the potential for more efficient and transparent operation of the combined system. Therefore, a collaboration will be formed between Black Hills Power, Cheyenne Light, the OCA and the Staff of the South Dakota Public Utilities Commission (to be invited, but not required to

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participate) for the purpose of thoughtfully evaluating the creation of a generation pool for the Applicants. The OCA and the Staff of the South Dakota Public Utilities Commission could become parties in any future proceeding before either the Wyoming Public Service Commission or the South Dakota Public Utilities Commission regarding any agreements that are reached among the parties to the collaborative. The first meeting of the collaborative will be held on or before October 1, 2012 at which time the parties to the collaborative will begin to jointly develop the study scope. The parties to the collaborative agree to meet thereafter as necessary to complete the study. Participation in this collaborative is not restricted to the parties to this CPCN proceeding but shall be open to any interested stakeholder or customer whose interests could be affected by the outcome of the collaborative. The Applicants shall be principally responsible for conducting the study with periodic review and comment by the other collaborators.

Possible considerations for study include:

- Existing power supply costs
- Expected power supply costs
- Off-system sales opportunities
- Transmission requirements
- Load characteristics
- Planning and operating reserves
- State and federal regulatory considerations and restrictions
- Structure of generation pool and related agreements
- Timing of implementation (if appropriate)
- Balancing purchases and sales
- Increased market access
- Plant dispatch
- Plant fuel requirements
- Other considerations as necessary

The study shall be conducted and completed by September 30, 2013. Should outside expertise be required to complete the study the Applicants agree to incur up to $100,000 of outside consulting or legal support costs at shareholder expense. Prior to the completion and publication of the report a draft shall be provided to the OCA and the Staff of the South Dakota Public Utilities Commission for review and comment. The final report shall be provided to each utility's respective state regulatory bodies on an informational basis. The parties to the collaborative will endeavor to reach agreements regarding the development of a power pool or other mechanisms to promote the efficient planning and operation of the Companies' electric generation resources and will identify, in the report, any agreements reached. However, any agreements reached by the parties to the collaborative would be subject to review and approval by the Commission in subsequent proceedings before the Commission."

Black Hills Corporation Gen-Fleet Operations

Black Hills Power & Cheyenne Light
Generation Pool Study
September 27-28, 2012

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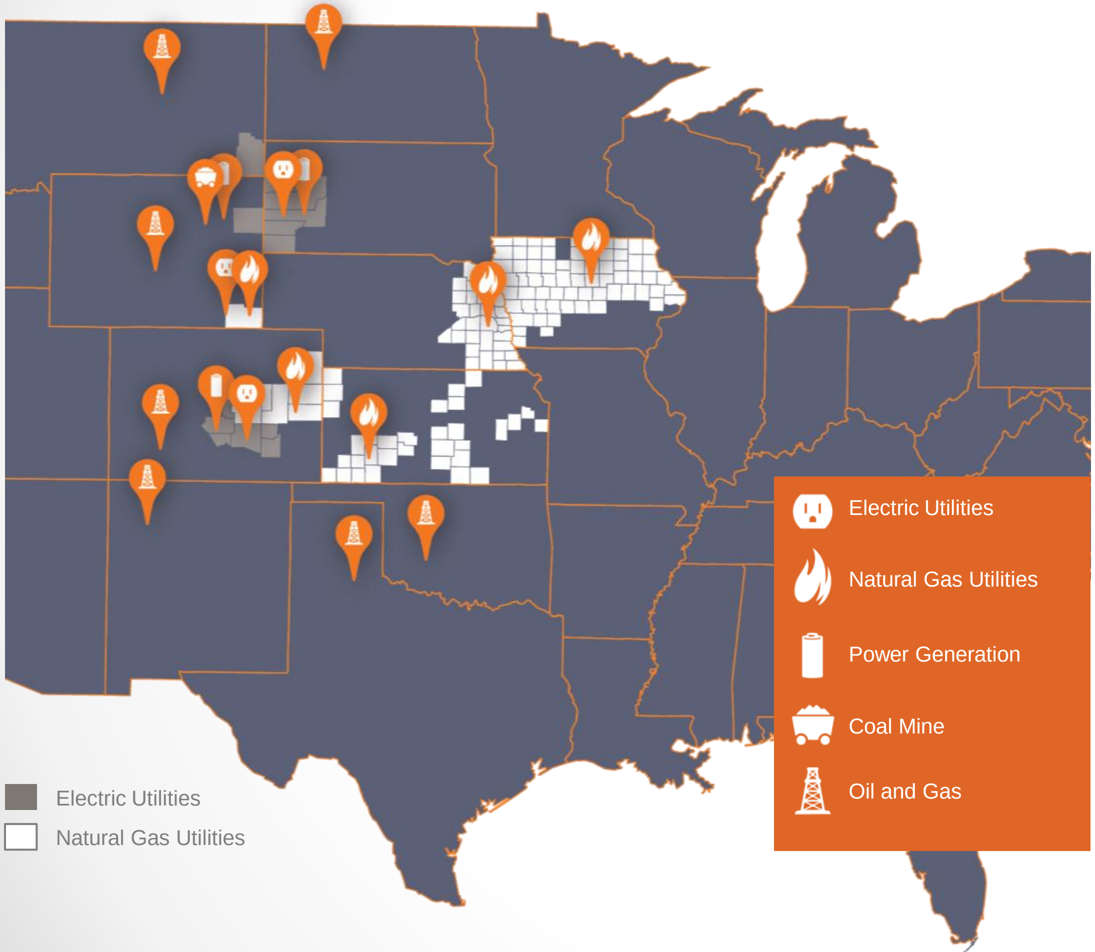
Black Hills Corporation – Diversified Energy



Utilities, Power Generation & Fuel Production

Utilities

Gas Utilities
- Colorado Gas
- Kansas Gas
- Nebraska Gas
- Iowa Gas

Electric Utilities
- Black Hills Power
- Cheyenne Light*
- Colorado Electric

Non-Regulated Energy

Power Generation
- Black Hills Electric Generation

Coal Mining
- Wyodak Resources

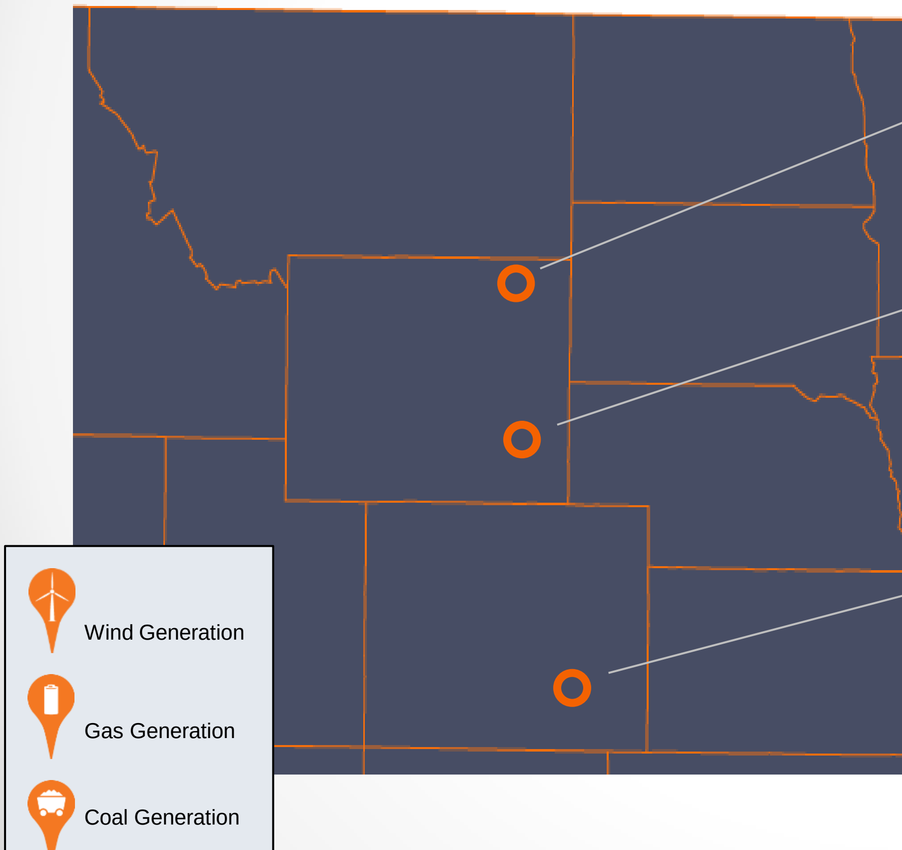
Oil and Gas
- Black Hills Exploration and Production

* Utility supplies electric and gas service to Cheyenne, Wyoming and vicinity

BHC Generation Sites

Mine Mouth Generation at our Gillette, Wyoming Energy Complex Provides Cost Effective Electricity to our Customers:

- Shared staff, facilities, land, infrastructure
- Each location has advantageous fuel supply logistics and/or wind potential
- Reduces asset concentration risk



Gillette Energy Complex

- 405 MW coal generation *
- 80 MW gas generation
- Future expansion opportunities

Cheyenne Complex

- Cheyenne Prairie Generating Station's 132 MW of gas generation online 2014 with future expansion opportunities
- Wind energy available through purchase agreements

Pueblo Complex

- 409 MW gas generation **
- 2012 - 29 MW wind generation with expansion opportunity

* Neil Simpson I with 21.8 MW scheduled for retirement on 3-21-14

**Pueblo #5 and #6 with 29 MW scheduled for operation suspension on 12-31-12

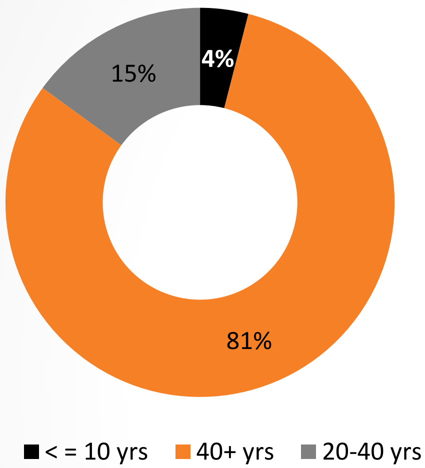
Gillette Complex

Aerial Photo of Gillette Complex

Source: Google Maps

Generation Coal Fleet

U.S.'s Aging Coal Fleet



BHC's Modern Operating Coal Fleet

NSII	- 17 years old
Wygen I	- 9 years old
Wygen II	– 5 years old
Wygen III	– 2 years old

96% of US Coal Fleet is older than 20 years
Approximately 35 coal plants < 20 Years Old
BHC Constructed and Operates Four (4) of these Newer Plants

Pueblo Airport Generating Station (PAGS)

State of the Art Natural Gas-Fired Generating Facility

Outlook for BHC - New Generation Projects

2012 -Pueblo Wind Project

- $52 million
- 29 MW wind site
- South of Pueblo, CO

Artist Rendering of the proposed:

2014 -Cheyenne Project

- $237 million
- 132 MW Gas Fired

Cheyenne Prairie Generating Station (Artist Rendering)

Generation Gross Capacity & Ownership

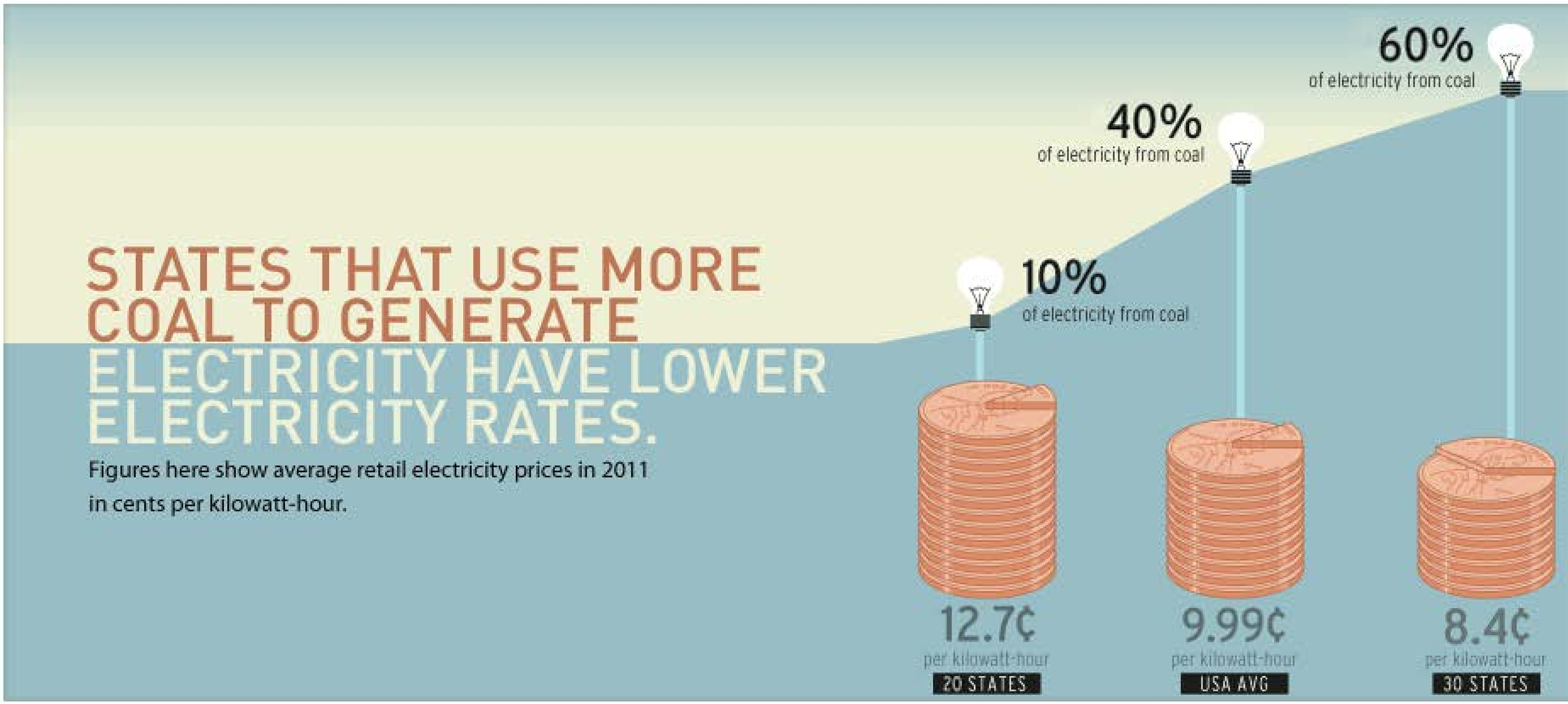
Plant	Year Commissioned	Owner	Location	Type of Unit	Planned Gross Capacity	Plant Utilization		Plant Status
NS I	1969 (May 22)	BHP	Gillette	Coal	22	Base Load	Regulated	Retire 2014 EPA MACT
NS II	1995 (Sept 5)	BHP	Gillette	Coal	90	Base Load	Regulated	
Wygen I	2003 (Jan 23)	BHW - 76.5%	Gillette	Coal	90	Base Load	Unregulated	
		MEAN - 23.5%	Gillette	Coal				
Wygen II	2008 (Jan 1)	CLF&P	Gillette	Coal	95	Base Load	Regulated	
Wygen III	2010 (Apr 1)	BHP - 52%	Gillette	Coal	110	Base Load	Regulated	
		MDU - 25%						
		COG - 23%						
CT I	2000 (June 19)	BHP	Gillette	Natural Gas	40	Peak	Regulated	
CT II	2001 (Apr 26)	BHW	Gillette	Natural Gas	40	Peak	Unregulated	
BF Steam	1960 (Apr 1)	BHP	Rapid City	Coal	25	Base Load	Regulated	Retire 2014 EPA MACT
BF Diesels (5)	1965 (Nov 25)	BHP	Rapid City	Diesel	10	Peak	Regulated	
BF CTs (1&2)	1977 (Aug 1)	BHP	Rapid City	Natural Gas	50	Peak	Regulated	
BF CT (3)	1978 (June 27)	BHP	Rapid City	Natural Gas	25	Peak	Regulated	
BF CT (4)	1979 (June 28)	BHP	Rapid City	Natural Gas	25	Peak	Regulated	
Lange CT	2002 (Mar 10)	BHP	Rapid City	Natural Gas	40	Peak	Regulated	
Osage 1	1948	BHP	Osage	Coal	11.5	Base Load	Regulated	Retire 2014 EPA MACT
Osage 2	1950	BHP	Osage	Coal	11.5	Base Load	Regulated	Retire 2014 EPA MACT
Osage 3	1952	BHP	Osage	Coal	11.5	Base Load	Regulated	Retire 2014 EPA MACT
Wyodak plt			Gillette				Regulated	

Wygen I - Joint Ownership Agreements

- Ownership
  - Black Hills Wyoming - 76.5%
  - Municipal Energy Agency of Nebraska - 23.5%
- Primary operating arrangements for BHW with MEAN:
  - Operating expenses - MEAN reimburses BHW for 23.5% of all operating expenses incurred for Wygen I, plus 23.5% of BHC's indirect corporate costs allocated to Wygen I and pro rata share of NSC common costs
  - Capital expenditures - as 23.% owner in undivided interest in Wygen I, MEAN contributes 23.5% of Wygen I's capital expenditures
  - Shared capital asset fee - MEAN is annually charged a fee representing its share of using certain NSC common site assets
  - Ash reclamation fee - MEAN is charged for its pro rata share of ash placed in the Peerless Pit which is owned by WRDC, BHC's coal mine supplying all coal to the NSC plants
  - Administrative fee

Wygen III - Joint Ownership Agreements

- Ownership:
  - Black Hills Power - 52%
  - Montana Dakota Utilities - 25%
  - City of Gillette - 23%
- Primary operating arrangements for BHP with MDU and COG:
  - Operating expenses - MDU and COG reimburses BHP for their respective shares of all operating expenses incurred for Wygen III, plus their respective shares of BHC's indirect corporate costs allocated to Wygen III and pro rata shares of NSC common costs
  - Capital expenditures - as owners of undivided interests in Wygen III, each contributes its share of Wygen III's capital expenditures
  - Shared capital asset fee - MDU and COG are annually charged fees representing their share of using certain NSC common site assets
  - Ash reclamation fee - MDU and COG are charged for their pro rata shares of ash placed in the Peerless Pit which is owned by WRDC, BHC's coal mine supplying all coal to the NSC plants
  - Administrative fee


STATES THAT USE MORE COAL TO GENERATE ELECTRICITY HAVE LOWER ELECTRICITY RATES.
Figures here show average retail electricity prices in 2011 in cents per kilowatt-hour.
10%
of electricity from coal
40%
of electricity from coal
60%
of electricity from coal
12.7¢
per kilowatt-hour
20 STATES
9.99¢
per kilowatt-hour
USA AVG
8.4¢
per kilowatt-hour
30 STATES

Thank You

Meeting Notes – September 27 - 28, 2012

Attendees:

In person: Kyle White, Lisa Seaman, Greg Hager, Mike Theis, Monni Karim, Brent Voorhees, Keith Miller, Jon Thurber (SD PUC staff), Greg Rislov (SD PUC staff), Randy Falkenberg (BH II – RFI Consulting, Inc.), Denise Parrish (WY OCA), Bryce Freeman (WY OCA),

Phone: Kenna Hagan, Andrew Moratzka (BH II – Mackall, Croune & Moore, PLC)

1. Reviewed Generation Pool Study background information
    a. A stipulation of the recently approved CPCN for CLFP and BHP jointly-owned generation in Cheyenne, Wyoming requires that BHP and CLFP conduct a generation pool study.

    b. Discussed CLFP, BHP and BHE Colorado Electric's generation fleet
        i. Greg Hager presented an overview of Black Hills Corp. generation fleet operations

    c. Discussed Existing and Pending Agreements
        i. Generation Dispatch and Energy Management Agreement (GDEMA)
        ii. Spinning Reserve Service Agreement
        iii. Economy Energy Service Agreement (pending with FERC)

    d. During the meetings several issues were raised and topics discussed that require further education, understanding and discussion and as a result Black Hills will facilitate a series of meetings that will include subject matter experts on the following topics.
        i. Transmission
        ii. Environmental Regulations
        iii. Generation Dispatch and Power Marketing operation
        iv. Production Cost Modeling – assumptions, scenarios, interpretation of results

    e. Objective of the study was defined
        i. To assess cost/benefit of utility power supply integration for an uncertain future.

2. Next Meetings
    a. Transmission System overview
    b. Environmental Regulations
    c. Generation Dispatch and Power Marketing Operation
    d. Production Cost Modeling

Meeting Agenda – November 15, 2012, 9:00 am

1. Review Sept 27 and 28, 2012 Meetings
    a. A stipulation of the recently approved CPCN for CLFP and BHP jointly-owned generation in Cheyenne, Wyoming requires that BHP and CLFP conduct a generation pool study.

    b. Discussed CLFP, BHP and BHE Colorado Electric's generation fleet

    c. Discussed Existing and Pending Agreements
        i. Generation Dispatch and Energy Management Agreement (GDEMA)
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    e. Objective of the study was defined
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2. Transmission System
    a. Common Use System
    b. CLFP Transmission System
    c. Transmission Paths
    d. Potential Transmission Expansion
    e. Reliability Impacts

3. Next Meetings
    a. Environmental Regulations – November 26th, 9:00 am
    b. Generation Dispatch and Power Marketing Operation - December 5th, 12:00 pm
    c. Production Cost Modeling - December 6th, 8:00 am

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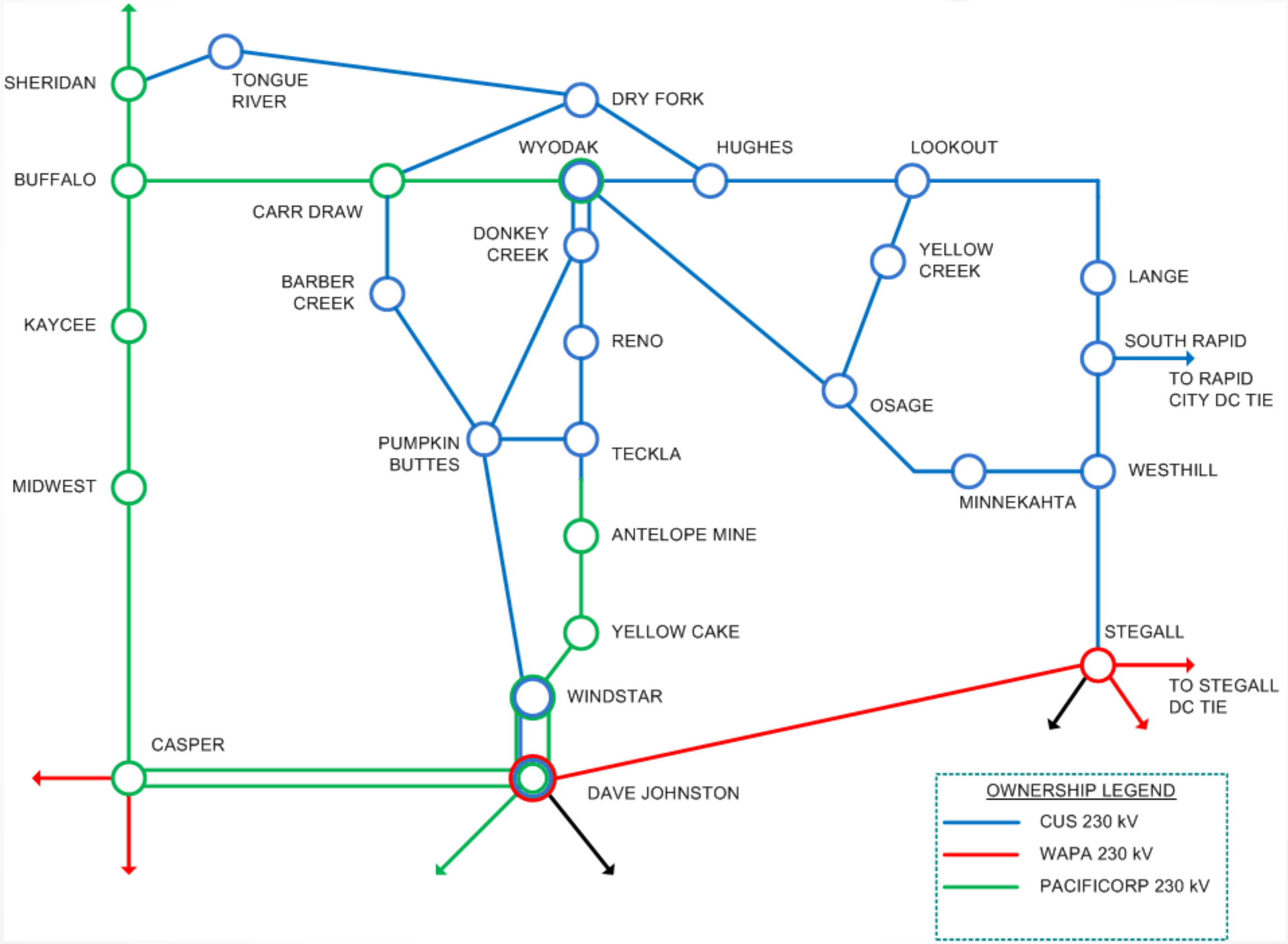
BHP/CLFP Transmission

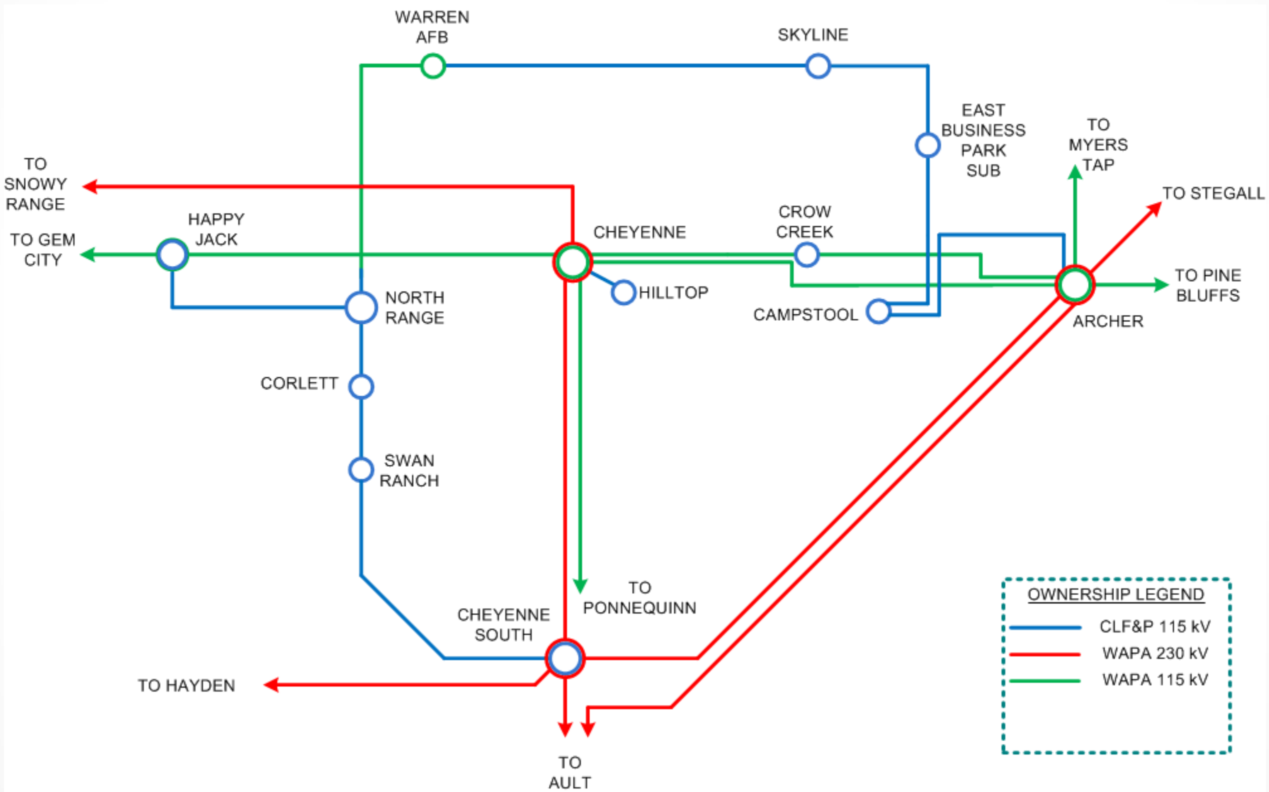
Common Use System

- Jointly owned and operated
  - Black Hills Power
  - Basin Electric Power Cooperative
  - Powder River Energy Corporation
- Joint Open Access Transmission Tariff
  - On file and approved by FERC
  - Joint Operating Agreement designates Black Hills as tariff administrator
  - Governed through the Common Use System Coordinating Committee
- Interconnections
  - WAPA-Rocky Mountain Region (Stegall, Dave Johnston)
  - WAPA-Upper Great Plains (Rapid City DC Tie)
  - PacifiCorp (Wyodak, Sheridan, Dave Johnston, Windstar)
  - Missouri Basin Power Project (Stegall, Dave Johnston)
- Loads & Resources
  - 865 MW peak load
  - ~ 1319 MW designated resources

Common Use System



CLFP System


WARREN AFB
SKYLINE
EAST BUSINESS PARK SUB
TO MYERS TAP
TO STEGALL
TO SNOWY RANGE
HAPPY JACK
TO GEM CITY
CHEYENNE
CROW CREEK
HILLTOP
CAMPSTOOL
TO PINE BLUFFS
ARCHER
NORTH RANGE
CORLETT
SWAN RANCH
CHEYENNE SOUTH
TO PONNEQUINN
TO HAYDEN
TO AULT
OWNERSHIP LEGEND
CLF&P 115 kV
WAPA 230 kV
WAPA 115 kV

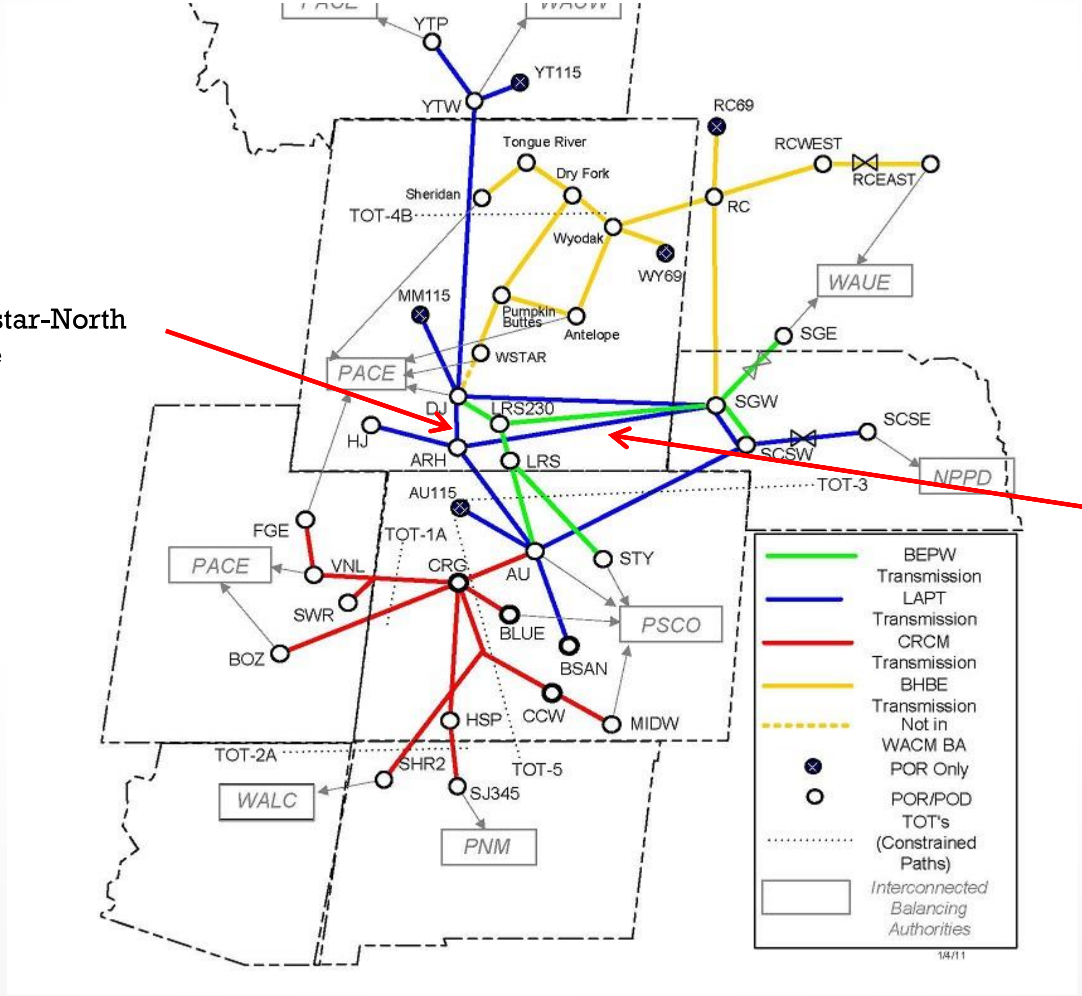
CLFP Transmission

- Load & Resources
  - 187 MW peak load
  - ~252 MW designated resources
  - All non-wind generating resources located off-system

- Transmission for Resource Delivery
  - CUS Network Customer
    - Full output of Wygen2 ~ 80 MW
  - CUS Point-to-Point Customer
    - 60 MW – Wyodak-Stegall Path
  - WAPA-LAPT Network Customer
    - 75 MW delivery from Stegall
    - 90 MW delivery from Dave Johnston
    - 170 MW delivery from Ault
    - Approximately $5.5 - $6.0 million annually

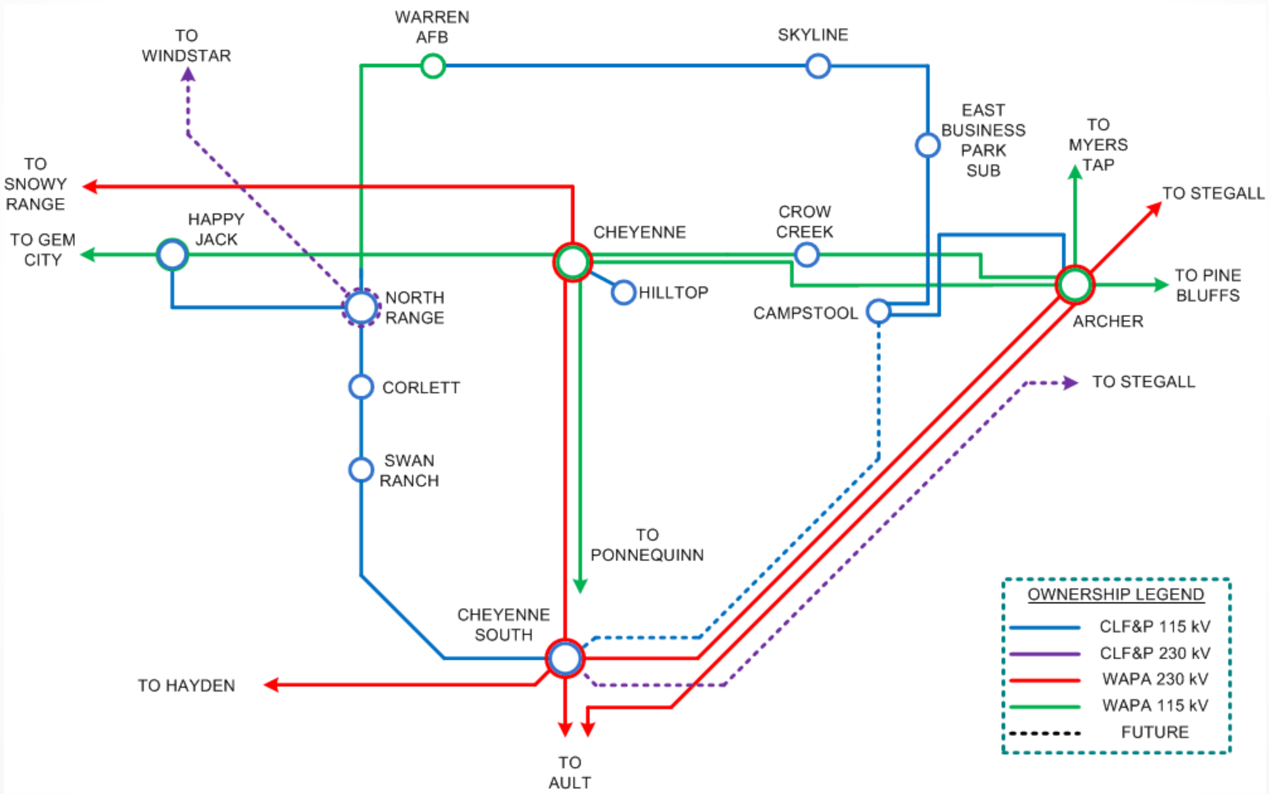
Transmission Paths

Windstar-North Range



Stegall-Terry Ranch Road

CLFP Expansion



Reliability Impacts

- No Impacts
  - Long-range transmission planning (1-10+ years)
    - Unit outage (N-1)
    - Prior outage + unit outage (N-1-1)
    - Breaker failure (N-2)
    - Annual study process
  - Operations transmission planning (0-1 years)
    - Planned outages (N-0)
    - Next contingency (N-1)
    - Based upon outage schedule

Transmission vs. Generation

- No “right” answer
  - Price of resource
  - Location of resource
  - Nature of transmission constraints

Questions

Meeting Notes – November 15, 2012, 9:00 am

Meeting attendees: Eric Egge, Kyle White, Andy Butcher, Lisa Seaman, Dory Batka, Brent Voorhees, Mike Theis, Dale Cottam (Hirst Applegate), Bryce Freeman (WY OCA), Denise Parrish (WY OCA), Jon Thurber (SD PUC staff), Katie Iverson, Randy Falkenberg (BH II - RFI Consulting, Inc.), Andrew Moratzka (BH II - Mackall, Croune & Moore, PLC)

1. Roll Call and Introductions

2. Reviewed topics discussed at September 27 and 28, 2012 Meetings
   a. The stipulation of the recently approved CPCN for CLFP and BHP jointly-owned generation in Cheyenne, Wyoming requires that BHP and CLFP conduct a generation pool study.

   b. Discussed CLFP, BHP and BHE Colorado Electric's generation fleet
      i. Greg Hager provided a PPT presentation that included information about the generation resources utilized by BHP and Cheyenne Light.

   c. Discussed Existing and Pending Agreements
      i. Generation Dispatch and Energy Management Agreement (GDEMA)
      ii. Spinning Reserve Service Agreement
      iii. Economy Energy Service Agreement (pending with FERC)

   d. During the meetings several issues were raised and topics discussed that require further education, understanding and discussion and as a result Black Hills will facilitate a series of meetings that will include subject matter experts on the following topics.
      i. Transmission
      ii. Environmental Regulations
      iii. Generation Dispatch and Power Marketing operation
      iv. Production Cost Modeling – assumptions, scenarios, interpretation of results

   e. Objective of the study was defined
      i. To assess cost/benefit of utility power supply integration for an uncertain future.

3. BHP and CLFP Transmission Systems
   a. Eric Egge, BH Transmission Planning, provided an overview of BHP's and CLFP's transmission systems. He discussed the following topics:
      i. Common Use System
      ii. CLFP Transmission System
      iii. Transmission Paths
      iv. Potential Transmission Expansion
      v. Reliability Impacts

4. Reviewed Schedule for next stakeholder meetings
   a. Environmental Regulations – November 26th, 9:00 am
   b. Generation Dispatch and Power Marketing Operation - December 5th, 12:00 pm
   c. Production Cost Modeling - December 6th, 8:00 am

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BHP/CLFP Generation Pool Study

Discussion of Environmental Issues Impacting Generation

New Environmental Regulations Impacting Power Generation

1. EPA—National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial and Institutional Boilers (aka Boiler MACT, aka Area Source Rules).
   a) Impacts coal fired boilers $\leq$ 25 MW.
   b) Deadline to comply = March 21, 2014
   c) Applicable to Ben French, Osage, NS 1
   d) Requirements; Hg, CO, coal quality, startup/shutdown, efficiency assessments, Hg sorbent injection rates, continuous monitoring, compliance testing.
   e) Impacts; addition of emission controls, restrictions on coal received based on parameters set during emission tests, adherence to operating parameters set during each compliance test
2. EPA—MATS or Mercury and Air Toxics Rule (aka Utility MACT Rule)
   a) Impacts boilers >25 MW
   b) Deadline to comply = April 17, 2015
   c) Applicable to Neil Simpson II, Wygens I, II and III
   d) Well positioned to comply; adding Hg absorbent injection systems
   e) Hg, PM, CO limitations; monitoring requirements, emission testing,
3. EPA---Regional Haze Rules (mandated by Clean Air Act). First implemented July 1, 1999
   a) Requires continuous reduction in man caused visual impairment in National Parks so as to achieve natural conditions by 2064. Primary targeted pollutants are NO_x, SO_2 and PM
   b) States mandated to review BART (Best Available Retrofit Technology) eligible sources (commenced operation between 8-7-1962 and 8-7-1977) for evaluations of new emission controls and submit an implementation plan to EPA demonstrating continuous visibility improvement on a "reasonable schedule" so as to eventually meet the 2064 goal.
   c) Once EPA approves the initial state plan, revisions and progress reports are due every 5 years, to include plans for addressing facilities not included in the first round.
   d) All emission sources with >250 tons per year of one of the targeted pollutants are included in the evaluation list---although the initial target is BART eligible sources for the first round.
   e) BHP/CLFP facilities not included in first round. Primary targets for 2nd round (WY and SD plans due to EPA in 2016) are Ben French, Osage, NS 1 and NS 2.
   f) Current status—SD's first plan approved by EPA; EPA has proposed rejection of the NO_x portion of WY's plan and wants to impose a federal implementation plan.
4. EPA---Greenhouse Gas (GHG) Tailoring Rule; permitting requirements effective July 1, 2011.
   a) Upon renewal of existing Title V operating permits, GHG emissions must be addressed (at this point we don't know specifics—EPA is developing guidelines)
   b) Title V expirations; Ben French = 7-8-2016; NS 1 = 3-10-2014; Osage = 8-6-2013
   c) WY currently not authorized to regulate GHG—anticipated for early 2014

5. EPA---National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)
   a) Applicable to all BHP diesel generators
   b) Deadline to comply = May 3, 2013
   c) Impacts; requires addition of oxidation catalysts to all diesel generators, emission tests, work practice requirements, recordkeeping

<u>Proposed Environmental Regulations Impacting Power Generation</u>

1. EPA---Proposed GHG New Source Performance Standards For Steam Utility Units
   a) Expect final rule by end of 2012
   b) Imposes GHG emission standards on new combined cycle combustion turbines and coal fired power plants
   c) Will be applicable to CPGS and any new coal fired unit or expansion of an existing unit
   d) Eliminates new coal fired generation—CO2 capture/sequestration is required in this proposed rule
2. EPA---will be developing a proposal for GHG emission standards for existing steam utility units
   a) Coal plants are the target
   b) Expect movement in 2013
3. EPA---Proposed changes to combustion turbine emission standards, operating requirements, define turbine overhauls.
   a) Public comment period ends December 29, 2012
   b) Main anticipated impact---define when existing units become subject to new standards as a result of engine overhauls
   c) Still reviewing proposal and will provide comments to EPA
4. EPA---Proposed revision of Ozone Ambient Air Quality Standard
   a) Scheduled for issuance of proposal in 2013
   b) Anticipate tightening of the standard. EPA maps indicate potential for nonattainment designations for counties in which our current SD and WY power generation is located.
   c) States required to submit plans to EPA for approval, detailing emission reductions necessary to return area to attainment status (primary target is NO_x).
5. EPA---Proposed revision of PM 2.5 Ambient Air Quality Standard
   a) Anticipate a final rule tightening the standard by December 14, 2012
   b) No initial projected impacts in our counties—may impact Wyodak Mine monitoring. Will impact future generation additions/modifications via emission modeling to demonstrate no impact on the ambient standard. Another step forcing the selection of natural gas over coal.
   c) If attainment issues arise—state develops plan to mitigate—to include PM emission reductions in the target area
6. EPA---Revision of effluent limitation guidelines for coal fired units
   a) Expect proposal by December 14, 2012 and a final rule by May 22, 2014
   b) Expect extensive list of metals, etc. to test for and restrictive concentration requirements

c) Would impact Ben French and Osage if operational when rule is finalized
d) Will affect Wyodak Plant ash pond and wastewater discharge permit. The Wyodak Plant holds the permit but we are named as contributing sources. Will need to evaluate proposal for potential impacts when issued.

7. EPA---Proposed coal ash disposal management standards
   a) Expect final determination in 2013
   b) Hazardous vs non-hazardous; federal vs state control
   c) Not applicable to mine backfill—OSM initiating reg development process—intent is to mirror EPA's final rule

<u>Future of Coal Fired Power Generation and Potential Election Impacts</u>

1. Court rulings on EPA's GHG Endangerment Finding and subsequent development of GHG regulations have so far been upheld. Absent a complete change of heart in Congress and the White House, resulting in laws overturning the GHG program, current regulations will go forward.
2. MATS rule is being challenged but don't expect any changes.
3. Outlook for future development of coal fired generation in U.S., at least for the next several years, is not positive. Will require an about face in the White House and Congress. Coal exports will help make up the slack but probably not to the extent of past coal sales.

Meeting Notes – December 3, 2012, 9:00 am

Meeting attendees: Fred Carl, Kyle White, Andy Butcher, Lisa Seaman, Brent Voorhees, Mike Theis, Bryce Freeman (WY OCA), Denise Parrish (WY OCA), Jon Thurber (SD PUC staff), Randy Falkenberg (BH II - RFI Consulting, Inc.)

1. Roll Call and Introductions

2. Environmental Issues Impacting BHP and CLFP Generation
    a. Fred Carl, BH Environmental Services, provided an overview of the environmental issues impacting BHP's and CLFP's generation facilities. He discussed the following topics:
        i. New Environmental Regulations Impacting Power Generation
        ii. Proposed Environmental Regulations Impacting Power Generation
        iii. Future of Coal Fired Power Generation and Potential Election Impacts

3. Reviewed Schedule for next stakeholder meetings
    a. Generation Dispatch and Power Marketing Operation - December 5th, 12:00 pm
    b. Production Cost Modeling - December 6th, 8:00 am

BHP & CLFP Generation Pool Study

Meeting Agenda – December 5, 2012, 1:00 pm
2828 Plant Street, Suite B
Lisa Seaman – 605-721-2278, cell phone 605-393-7202

Wednesday, December 5, 2012

1:00 pm	Introductions Brief Review of Project Progress Generation Dispatch and Power Marketing Presentation Break Generation Dispatch and Power Marketing Tour
5:30 pm	Dinner at Botticelli's Restaurant 523 Main Street, Rapid City

Thursday, December 6, 2012

8:00 am	Generation Pool Modeling Discussion Modeling Approach Load Forecast Production Cost Modeling Modeling Assumptions Scenarios
11:30	Generation Pool Study Next Steps

Once you arrive at 2828 Plant Street, Suite B

The portion of the Plant Street building that the Generation Dispatch and Power Marketing group works in is a secure area that requires guests to be registered with BHC security and accompanied by a BHC employee while in the building. When you arrive at the Plant Street building enter the Suite B door and if I am not waiting for you please knock on the inside door to get my attention or call my phone at 605-721-2278 or 605-393-7202.

Black Hills Corporation
Improving life with energy

Driving Directions

DRIVING DIRECTIONS from Holiday Inn RAPID CITY-RUSHMORE PLAZA, 505 North Fifth St, Rapid City, SD to 2828 Plant Street

----

1. Start out going southwest on N 5th St toward New York St. (go 0.35 miles)
2. Take the 1st right onto Omaha St/SD-44 W. Continue to follow Omaha St.
   - Omaha St is 0.1 miles past New York St
   - If you reach Rapid St you've gone about 0.1 miles too far (go 1.5 miles)
3. Omaha St becomes W Chicago St. (go 0.13 miles)
4. W Chicago St becomes Deadwood Ave N. (go 0.69 miles)
5. Turn left onto Plant St.
   - Plant St is 0.2 miles past Cement Plant Rd
   - If you reach Lien St you've gone about 0.2 miles too far

   (go 0.06 miles)
6. 2828 PLANT ST. - If you reach Industrial Ave you've gone a little too far (go 0 miles)

>> TOTAL ESTIMATED TIME: 5 minutes | DISTANCE: 2.73 miles

To view your map, click on the link below or copy and paste it to your browser:
http://mapq.st/VgPlLJ

DRIVING DIRECTIONS

A) Rapid City Regional Airport (RAP), 4550 Terminal Rd # 102, Rapid City to 2828 Plant Street

----

1. Start out going northwest on Terminal Rd. (go 0.15 miles)
2. Turn right toward Rental Car Return.
   - If you reach RTR Rd you've gone about 0.2 miles too far

   (go 0.18 miles)
3. Turn left onto Airport Rd. (go 1.19 miles)
4. Turn right onto SD-44 W.
   - SD-44 W is 0.2 miles past Aviation Rd (go 9.4 miles)
5. SD-44 W becomes W Omaha St. (go 0.98 miles)
6. W Omaha St becomes W Chicago St. (go 0.13 miles)
7. W Chicago St becomes Deadwood Ave N. (go 0.69 miles)
8. Turn left onto Plant St.
   - Plant St is 0.2 miles past Cement Plant Rd
   - If you reach Lien St you've gone about 0.2 miles too far (go 0.06 miles)
9. [2601-2704] PLANT ST. - If you reach Industrial Ave you've gone a little too far (go 0 miles)

>> TOTAL ESTIMATED TIME: 21 minutes | DISTANCE: 12.78 miles

To view your map, click on the link below or copy and paste it to your browser:
http://mapq.st/VrKM39

Generation Dispatch and Power Marketing

BHP, CLFP, BHCE, BHW

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Processes and Activities

GDPM Customers

- **Black Hills Power**
  - Serve Load: Peak Load 452 MW. (July 19, 2011 HE16)
  - Generation Dispatch for 8 Coal Units, 6 Gas Turbines and 5 Diesels. Total Capacity of over 500 MW of Generation.
  - 20 MW and 15 MW Contract of Wind Energy.
  - 50 MW Contract of Firm Energy Capacity.
  - Generation Dispatch and Energy Management Services. Budget of over $3,000,000 for 2012
    - Shared amongst all GDPM customers by the FERC Filed Schedule B of GDEMAs
  - Manage System Reserves.

- **Cheyenne Light, Fuel and Power**
  - Serve Load: Peak Load 187 MW. (July 20, 2012 HE16)
  - Generation Dispatch for 1 Coal Unit of 92MW.
  - 60 MW Contract from Wygen 1 and 40 MW Contract from BHW Gas Combustion Turbine.
  - 10 MW and 15 MW Contract of Wind Energy
  - Upcoming 132 MW Cheyenne Prairie Generation Station – NEW Gas Combustion Turbines
  - Manage System Reserves.

- **Black Hills Wyoming**
  - Generation Dispatch for a Coal Unit and a Gas Combustion Turbine.

GDPM Customers

- **Black Hills Colorado Electric**
  - Serve Load: Peak Load 400 MW. (June 26, 2012 HE17)
  - Generation Dispatch for 2 Coal Units, 2 Gas Boilers, 14 Diesels, 2 LMS100 Gas Combustion Turbines, and 2 Combined Cycle LM6000 Gas Combustion/Steam Turbines. Total Capacity of over 480 MW of Generation.
  - 29 MW Wind Energy – on-line October 2012.
  - Call option on 3 Customer Owned Diesels.
  - 100 MW in Firm Energy Capacity Contracts
  - Manage System Reserves

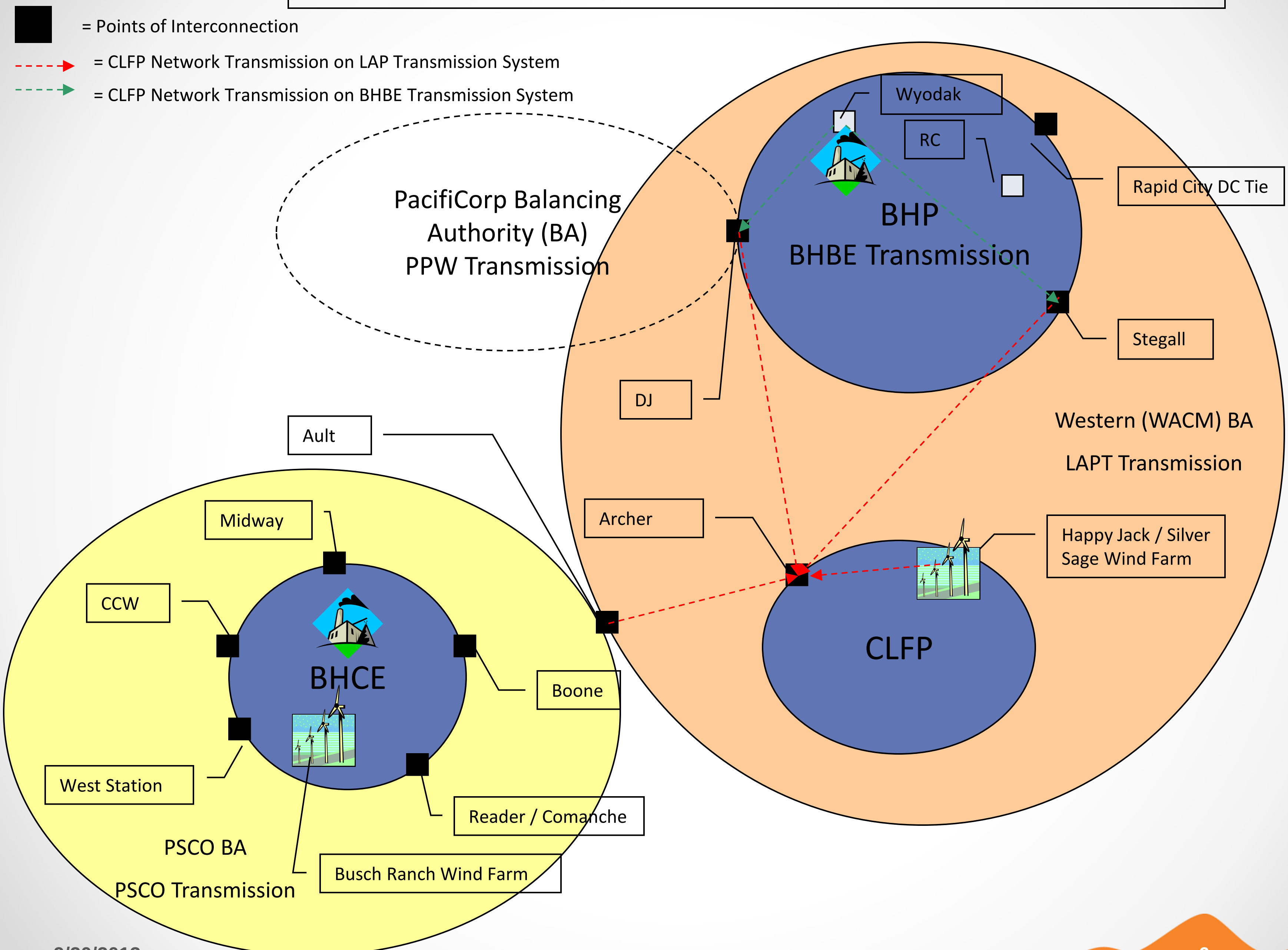
- **Generation Dispatch Energy Management Agreements**
  - City of Gillette
  - MDU / Sheridan

- **Rocky Mountain Reserve Group**
  - Reserve responsibilities for BHP/CLFP and BHCE

GDPM Priorities

1. **System Reliability** of the Bulk Electric System
2. **Lowest Cost Resources** to the Customers
3. **Capture Margin** from unused Resources

BHP / CLFP / BHCE Electric Utility Interconnection Map



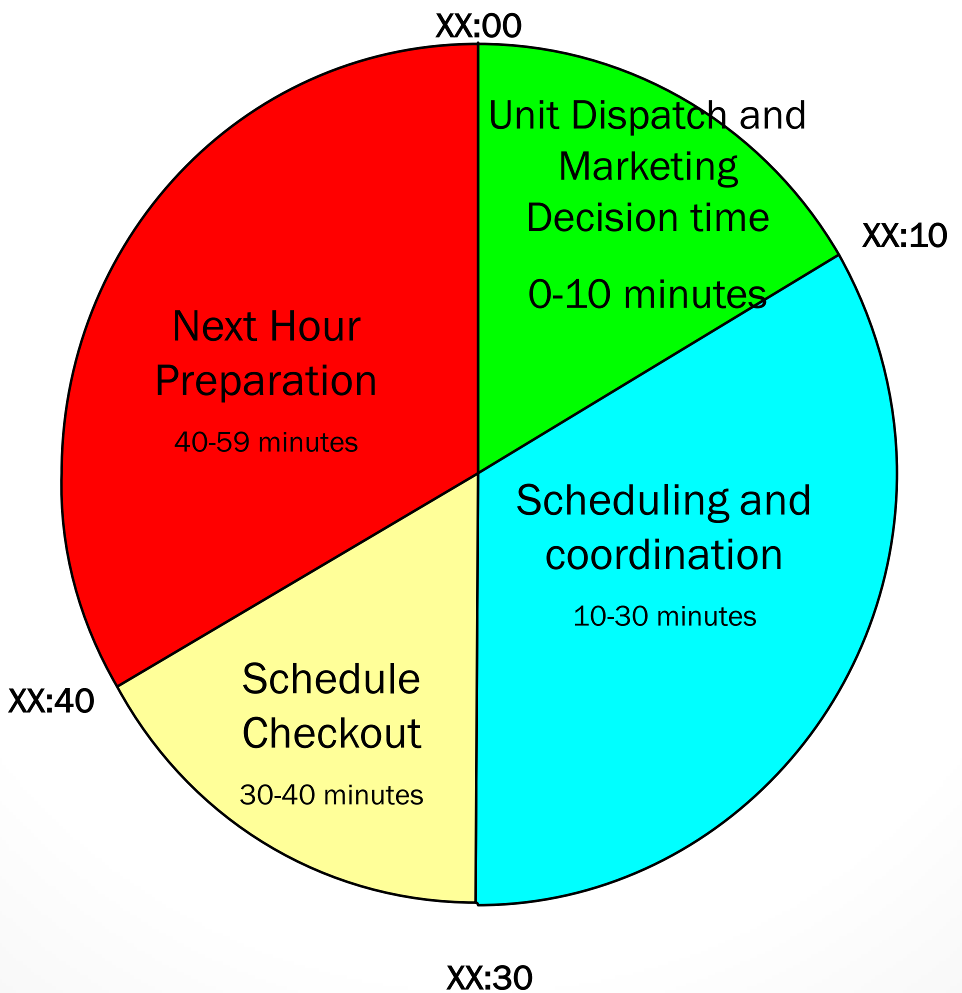
Day Ahead Activities

Daily Process

- Align duties with the Preschedule Calendar
- Check Transmission Status in various regions
- Verify Load Forecasts
- Verify Generation Forecasts and Schedules
- Determine best approach to Economic Dispatch of all units
- Perform Market exploration
- Execute Trades
- Purchase Transmission
- Tagging and Scheduling
- Daily Market Reports

Real Time Activities

Real Time Scheduling Cycle



Real Time Duties

- Load Forecast and Resource Balance for BHP/CLFP/BHCE and others for next hour
- Make decision to buy / sell energy
- Verify Transmission Availability
- Call Counterparties to make Trades
- Purchase necessary transmission
- Create e-Tag for transactions
- Enter deal information in webTrader
- Verify Load / Schedules / Last hour inadvertent
- Manage Reserves
- Monitor Generation Status and Area Control Error (ACE)

Real Time - continued

- Generation Curtailments and Outages
- Monitor Most Severe Single Contingency Reporting
- Joint Ownership Unit Coordination
- Wind Farm Load Balancing
- FERC 888 / 890 Verification
- Compliance with BHC Risk Policy

Reserves

- BHP, CLFP and BHCE must respond to RMRG reserve contingencies by deploying required spinning and non-spinning reserves in a timely manner
    - Reserves must be fully deployed within 15 minutes of the unit trip. The overall notification can take up to 5 minutes, so all reserves must be fully deployed within **10** minutes
    - Our performance will be measured based on overall interchange increase
    - During the 15 minute reserve contingency, **<u>ALL Generating units</u>** not ramping for the activation, **MUST NOT** reduce generation
- Failure to meet this reserve obligation may result in severe monetary fines and penalties levied against the participants.

How do we serve BHP and CLFP?

- Loads are served in two very different ways:
  - Physically – through hourly load and resource balancing utilizing all generation and market products available
    - Accomplished through Tags and Schedules
  - Financially – through merit stacking of resources and contracts in order to meet their load requirements
    - Accomplished through Modeling tools
- BHP and CLFP share one Area Control Error (ACE) within the Western Area Power Administration Balancing Authority
  - "ACE" is how well you predicted what was going to happen within your system, and this value is monitored and updated every six seconds
  - Since they share one ACE, what happens to the load in one entity has balancing effects on the other and vice versa
  - BHP and CLFP are partners in the Energy Imbalance Agreement with Western to regulate our system
- The following slides show a detailed comparison of the two ways of serving the loads.

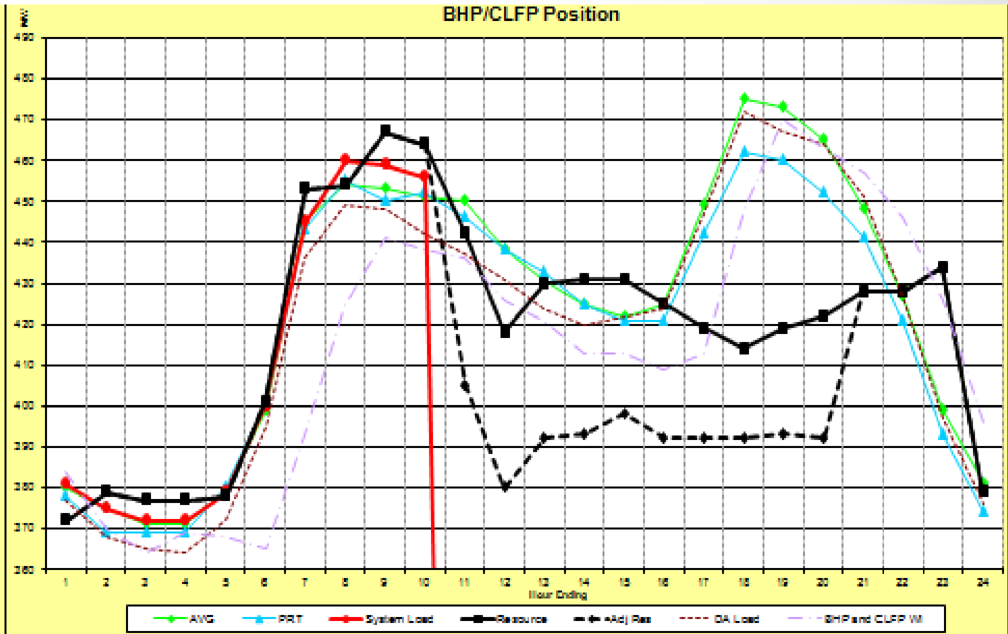
BHP/CLFP Load Chart

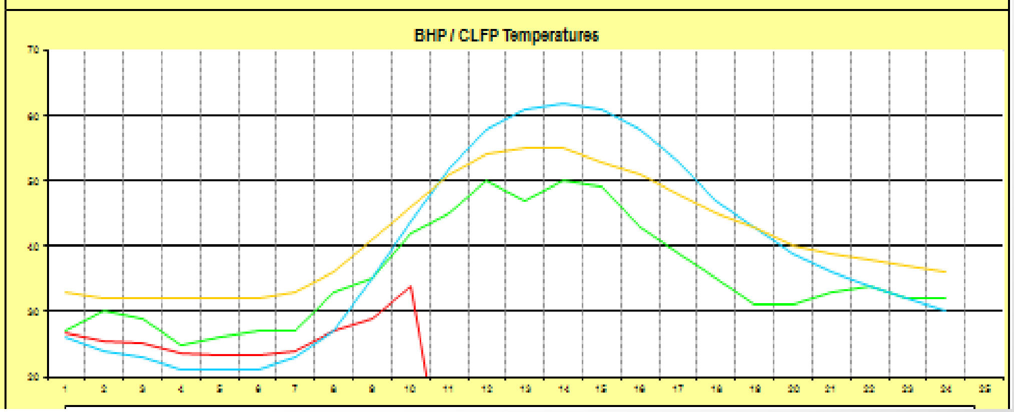
Wednesday November 28, 2012

Load Fix	HE	ADJUSTMENT 102% AVG Hourly	100% PRT	Wait Sched	Wheel Load	BHP Load	CLFP Load	System Load	ACTUAL GEN	OATi GEN	Total Resource	Position w/ HOURLY	w/ DAILY
!	1	380	378	2	32	261	120	381	406	407	372	-8	-6
!	2	375	369	-1	33	258	117	375	411	407	379	4	10
!	3	371	369	4	33	256	116	372	414	407	377	6	8
!	4	371	369	0	33	257	115	372	410	407	377	6	8
!	5	379	380	-2	35	261	118	379	411	406	378	-1	-2
!	6	399	401	-34	42	274	126	400	409	407	401	2	0
!	7	445	443	-84	46	308	137	445	415	407	453	8	10
!	8	454	455	-83	48	319	141	460	419	417	454	0	-1
!	9	453	450	-84	46	316	143	459	429	417	467	14	17
!	10	451	452	-74	45	313	143	456	435	417	464	13	12
!	11	450	446	-69	44	0	0	0	3	417	442	-8	-4
!	12	438	438	-54	43	0	0	0	3	407	418	-20	-20
!	13	431	433	-63	40	0	0	0	3	407	430	-1	-3
!	14	425	425	-64	40	0	0	0	3	407	431	6	6
!	15	422	421	-63	39	0	0	0	3	407	431	9	10
!	16	425	421	-57	39	0	0	0	3	407	425	0	4
!	17	449	442	-57	45	0	0	0	3	407	419	-30	-23
!	18	475	462	-58	51	0	0	0	3	407	414	-61	-48
!	19	473	460	-62	50	0	0	0	3	407	419	-54	-41
!	20	465	452	-66	51	0	0	0	3	407	422	-43	-30
!	21	448	441	-70	49	0	0	0	3	407	428	-20	-13
!	22	427	421	-63	42	0	0	0	3	407	428	1	7
!	23	399	393	-66	39	0	0	0	3	407	434	35	41
!	24	381	374	-6	34	0	0	0	3	407	379	-2	5

PT	HE	Pending Adj Schedule	Adj Res	Adjusted Hourly	Adjusted 4Cast	BHP only DA Load	Diff from DA Load	NEW LOAD	System [illegible]	NEW Adj Schedule	BHP RT DMR	CLFP DMR	BHP Net Gen Diff
24	1		372	-8	-6	256	-5	372	-6	2	4	0	(4)
1	2		379	4	10	250	-8	379	7	-1	10	0	(4)
2	3		377	6	8	248	-8	377	5	4	12	0	(4)
3	4		377	6	8	247	-10	377	10	0	17	0	(4)
4	5		378	-1	-2	253	-8	378	1	-2	12	0	(4)
5	6		401	2	0	268	-6	401	5	-34	0	0	(4)
6	7		453	8	10	299	-9	453	10	-84	0	0	(1)
7	8		454	0	-1	308	-11	454	-3	-83	0	0	(1)
8	9		467	14	17	306	-10	467	10	-84	15	0	(1)
9	10		464	13	12	301	-12	464	122	-74	17	0	(1)
10	11	-37	405	-45	-41	296	-7	368	69	-32	3	0	5
11	12	-38	380	-58	-58	291	-5	342	54	-16	5	0	4
12	13	-38	392	-39	-41	284	-7	354	63	-25	13	0	4
13	14	-38	393	-32	-32	282	-3	355	64	-26	35	0	4
14	15	-33	398	-24	-23	283	1	365	63	-30	34	0	4
15	16	-33	392	-33	-29	285	3	359	57	-24	8	0	4
16	17	-27	392	-57	-50	302	3	365	57	-30	0	0	4
17	18	-22	392	-83	-70	319	8	370	58	-36	0	0	4
18	19	-26	393	-80	-67	315	6	367	62	-36	0	0	4
19	20	-30	392	-73	-60	314	10	362	66	-36	0	0	4

REFRESH





BHP/CLFP Load Chart (2012 CLFP Peak)

Friday July 20, 2012

HE	ADJUSTMENT 100% AVG Hourly	ADJUSTMENT 100% Fri 7/20/12 PRT	Want Sched	Wheel Load	BHP Load	CLFP Load	System Load	ACTUAL GEN	OATi GEN	Total Resources	Position w/ HOURLY	Position w/ DAILY
1	367	426	-126	34	291	131	422	331	335	423	56	-3
2	347	401	-100	34	268	125	393	332	337	398	51	-3
3	337	389	-82	30	257	120	377	333	337	385	48	-4
4	327	376	-64	29	249	118	367	334	337	369	42	-7
5	327	370	-59	28	250	118	368	337	337	368	41	-2
6	336	375	-73	30	255	121	376	335	337	378	42	3
7	365	402	-103	33	276	126	402	335	337	405	40	3
8	407	449	-154	43	309	138	447	338	335	449	42	0
9	441	490	-204	52	335	149	484	337	337	489	48	-1
10	474	523	-238	58	359	161	520	345	336	525	51	2
11	497	551	-220	63	380	168	548	379	383	536	39	-15
12	520	572	-236	70	392	176	568	405	419	571	51	-1
13	537	587	-238	73	404	180	584	409	416	574	37	-13
14	550	600	-254	75	416	183	599	409	416	588	38	-12
15	562	606	-272	75	421	185	606	401	414	598	36	-8
16	572	605	-284	78	407	187	594	410	412	616	44	11
17	573	587	-275	77	403	187	590	398	409	596	23	9
18	560	572	-246	77	386	181	567	397	412	566	6	-6
19	543	550	-241	72	370	172	542	392	402	561	18	11
20	519	523	-237	69	346	165	511	370	370	538	19	15
21	497	496	-194	68	329	161	490	367	372	493	-4	-3
22	484	479	-176	62	326	160	486	370	374	484	0	5
23	442	446	-153	53	301	149	450	362	346	462	20	16
24	406	410	-89	44	280	138	418	356	348	401	-5	-9

HE	Pending Adj Schedule	Adj Res	Adjusted Hourly	Adjusted 4Cast	BHP only DA Load	Diff from DA Load	NEW LOAD	System Inadvertent	NEW Adj Schedule	BHP RT DHR	CLFP DHR	BHP Net Gen Diff
1		423	56	-3	277	-14	423	10	-126	0	0	(4)
2		398	51	-3	261	-7	398	12	-100	0	0	(4)
3		385	48	-4	252	-5	385	17	-82	5	0	(3)
4		369	42	-7	242	-7	369	5	-64	0	0	(1)
5		368	41	-2	243	-7	368	-1	-59	0	0	(1)
6		378	42	3	247	-8	378	11	-73	12	0	(4)
7		405	40	3	264	-12	405	9	-103	0	0	(4)
8		449	42	0	302	-7	449	0	-154	48	0	(5)
9		489	48	-1	334	-1	489	9	-204	32	0	(5)
10		525	51	2	362	3	525	8	-238	36	0	(5)
11		536	39	-15	389	9	536	-9	-220	45	0	(33)
12		571	51	-1	407	15	571	12	-236	57	0	(6)
13		574	37	-13	422	18	574	-10	-238	141	0	(34)
14		588	38	-12	431	15	588	-9	-254	139	15	(15)
15		598	36	-8	432	11	598	5	-272	146	14	(7)
16		616	44	11	434	27	616	18	-284	145	25	(6)
17		596	23	9	424	21	596	16	-275	153	14	(6)
18		566	6	-6	405	19	566	16	-246	158	0	(6)
19		561	18	11	388	18	561	20	-241	163	0	(4)
20		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]

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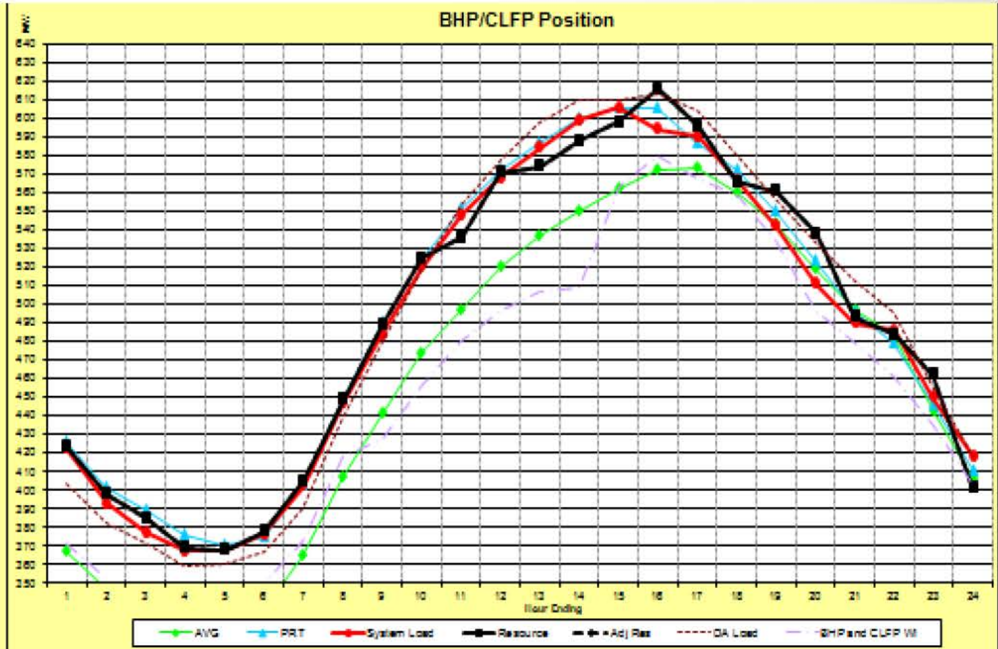
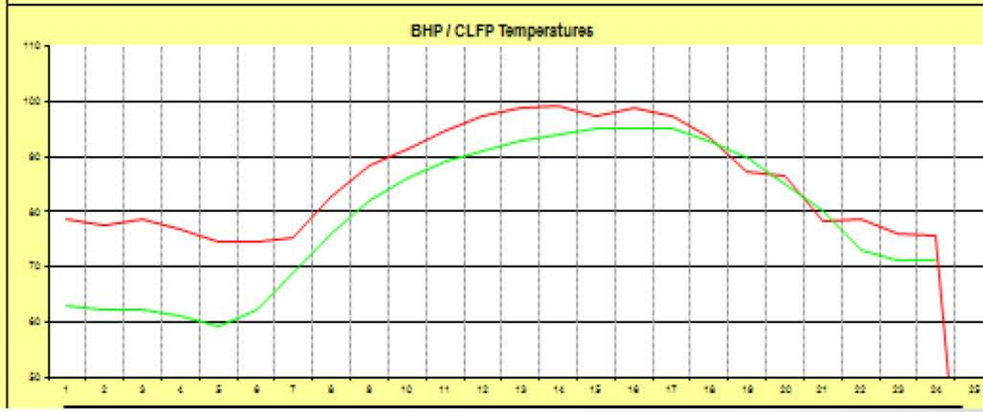




Other FERC Contracts

- Generation Dispatch Energy Management Agreements
- Economy Energy Sharing Agreement
- Spinning Reserve Sharing Agreement
- Proposed – Capacity Sharing Agreement

Value Provided

- Displacement arrangement which creates value to each utility by:
    - Savings on Transmission Losses
    - Savings on Transmission Costs
- Shared Dispatch Center costs
- Shared BA and TP Imbalance Services and Costs
- Combined purchase / sale operations creates greater economies of scale
- Combined Wind Farm operations reduces scheduling costs
- Cooperative reserve management
- Value added in entity representation with WECC, FERC, NERC, and WSPP
- Proposed Value in Capacity Sharing between Utilities

Questions?

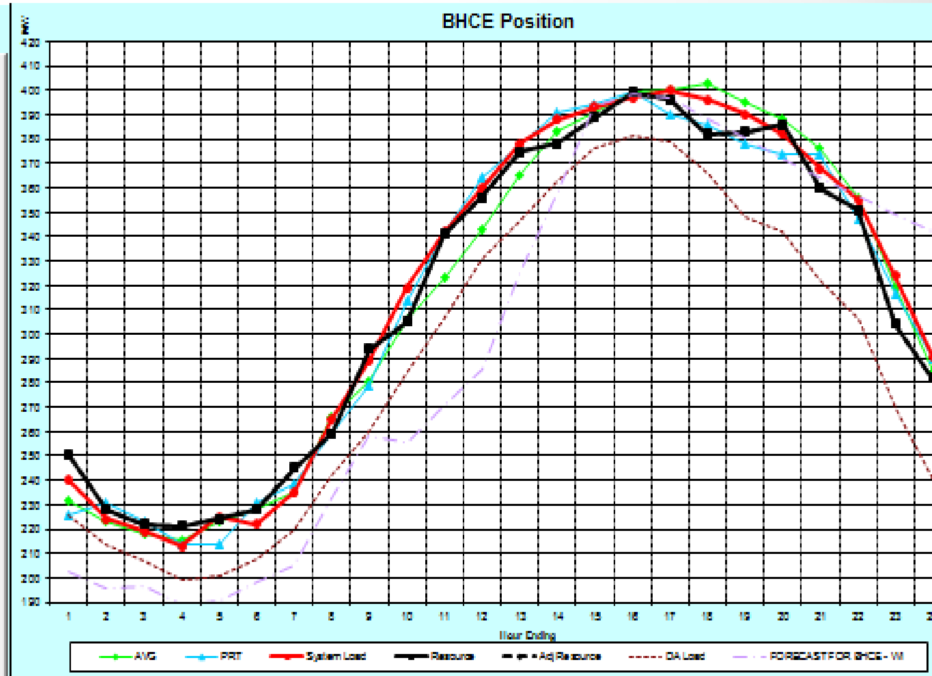
BHCE Load Chart (2012 Peak)

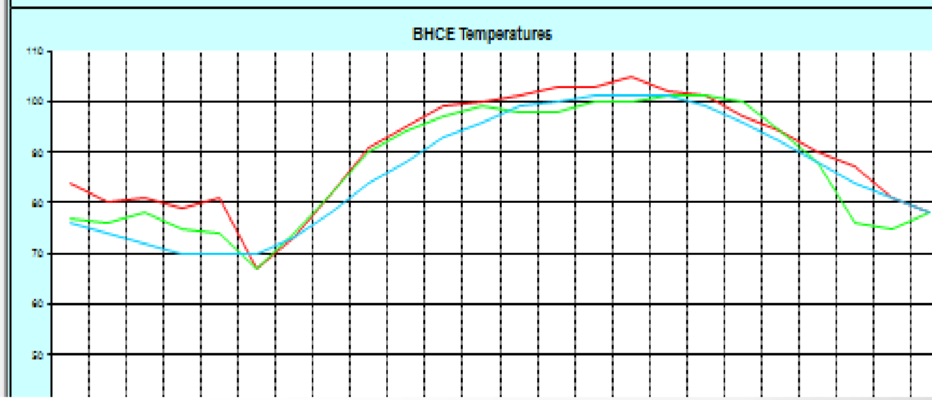
Tuesday June 26, 2012

PT	HE	ADJUSTMENT 106% AVG Hourly	100% Tue 6/26/12 PRT	GAS USAGE	GAS DIFF -786.05%	BHCE Imports	BHCE Exports	BHCE Wheel	BHCE Load	ACTUAL GEN	OATi GEN	Total Resources	Position w/ HOURLY	w/ DAILY
:4	1	232	226	136		211	0	9	240	39	42	250	18	24
1	2	223	231	0		203	2	9	224	27	27	228	5	-3
2	3	218	223	0		196	2	10	219	28	28	222	4	-1
3	4	215	214	0		196	2	9	213	27	28	221	6	7
4	5	223	214	0		196	2	10	225	30	30	224	1	10
5	6	228	231	52		201	2	9	222	29	29	228	0	-3
6	7	235	238	469		176	1	10	235	70	71	245	10	7
7	8	266	259	1161		98	2	9	265	163	162	259	-7	0
8	9	280	279	1585		103	28	10	289	219	218	294	14	15
9	10	306	314	1882		43	0	9	319	262	260	305	-1	-9
10	11	323	342	2051		49	0	10	342	292	292	341	18	-1
11	12	343	364	2162		49	0	10	360	307	318	356	13	-8
12	13	365	377	2162		64	0	10	378	311	320	375	10	-2
13	14	383	391	2210		62	0	9	388	316	321	378	-5	-13
14	15	391	394	2223		77	1	10	393	313	321	389	-2	-5
15	16	399	399	2227		82	1	9	397	318	321	399	0	0
16	17	400	390	2219		78	1	10	400	319	321	396	-4	6
17	18	403	386	2216		68	1	10	396	315	321	382	-21	-4
18	19	395	378	2222		69	1	10	390	315	321	383	-12	5
19	20	388	374	2196		74	0	10	382	312	321	386	-2	12
:0	21	376	374	2163		54	0	9	368	306	316	360	-16	-14
21	22	356	347	2121		50	0	10	355	301	306	351	-5	4
:2	23	319	316	1414		98	2	9	324	208	216	304	-15	-12
:3	24	285	290	719		161	0	10	291	121	116	282	-3	-8

REFRESH

PT	HE	Pending Adj Schedule	Adj Resources	Adjusted Hourly	Adjusted 4Cast	BHCE DA Load	Diff From DA Load	NEW LOAD	AVG LOAD	BHCE Inadvertent	BHCE Schedule	NEW Schedule	BHCE RT DHR	GAS ORDER
:4	1		250	18	24	226	-14	250	229	10	39	39	6	133
1	2		228	5	-3	214	-10	228	227	4	27	27	2	165
2	3		222	4	-1	207	-12	222	221	3	28	28	2	148
3	4		221	6	7	199	-14	221	215	8	27	27	2	126
4	5		224	1	10	201	-24	224	219	-1	30	30	2	120
5	6		228	0	-3	208	-14	228	230	6	29	29	2	126
6	7		245	10	7	220	-15	245	237	10	70	70	177	173
7	8		259	-7	0	242	-23	259	263	-6	163	163	98	127
8	9		294	14	15	260	-29	294	280	5	219	219	79	159
9	10		305	-1	-9	285	-34	305	310	-14	262	262	5	162
10	11		341	18	-1	307	-35	341	333	-1	292	292	74	168
11	12		356	13	-8	331	-29	356	354	-4	307	307	50	169
12	13		375	10	-2	346	-32	375	371	-3	311	311	35	165
13	14		378	-5	-13	363	-25	378	387	-10	316	316	15	169
14	15		389	-2	-5	376	-17	389	393	-4	313	313	5	168
15	16		399	0	0	381	-16	399	399	2	318	318	5	169
16	17		396	-4	6	379	-21	396	395	-4	319	319	5	169
17	18		382	-21	-4	366	-30	382	395	-14	315	315	14	163





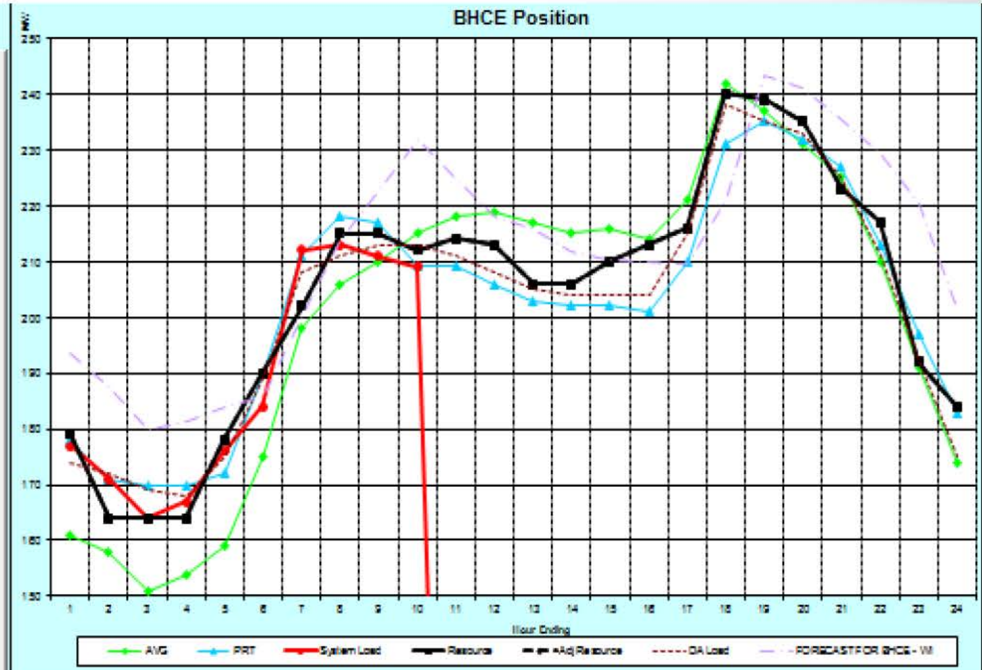
BHCE Load Chart

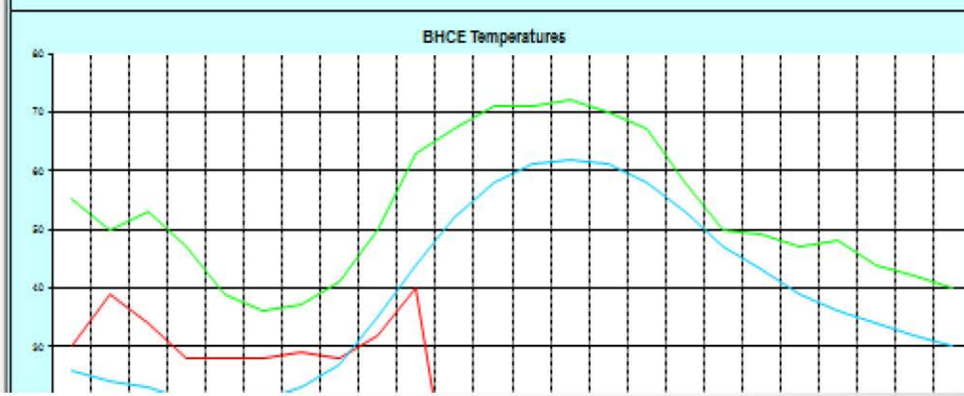
Wednesday November 28, 2012

PT	HE	ADJUSTMENT 105% AVG Hourly	100% PRT	GAS USAGE	GAS ORDER	BHCE Imports	BHCE Exports	BHCE Wheel	BHCE Load	ACTUAL GEN	OATi GEN	Total Resources	Position w/ HOURLY	Position w/ DAILY
24	1	161	178	376	0	101	0	9	177	78	83	179	18	1
1	2	158	171	307	0	101	0	9	171	63	80	164	6	-7
2	3	151	170	247	0	111	0	9	164	53	75	164	13	-6
3	4	154	170	235	0	111	1	9	167	54	76	164	10	-6
4	5	159	172	341	0	111	0	9	176	67	77	178	19	6
5	6	175	190	1071	0	101	75	9	184	164	166	190	15	0
6	7	198	211	1459	0	102	126	9	212	226	230	202	4	-9
7	8	206	218	1190	0	102	76	9	213	189	185	215	9	-3
8	9	210	217	1164	1,500	102	76	8	211	189	185	215	5	-2
9	10	215	209	1149	1,500	103	75	9	209	184	185	212	-3	3
10	11	218	209	0	1,500	104	75	8	0	0	185	214	-4	5
11	12	219	206	0	1,500	103	75	8	0	0	185	213	-6	7
12	13	217	203	0	1,500	101	100	9	0	0	205	206	-11	3
13	14	215	202	0	1,500	101	100	9	0	0	205	206	-9	4
14	15	216	202	0	1,500	101	100	9	0	0	209	210	-6	8
15	16	214	201	0	1,500	102	100	9	0	0	211	213	-1	12
16	17	221	210	0	1,500	102	100	9	0	0	214	216	-5	6
17	18	242	231	0	1,500	53	125	8	0	0	312	240	-2	9
18	19	237	235	0	1,500	54	110	9	0	0	295	239	2	4
19	20	231	232	0	1,500	54	110	9	0	0	291	235	4	3
20	21	225	227	0	1,500	53	120	8	0	0	290	223	-2	-4
21	22	210	213	0	1,500	101	110	8	0	0	226	217	7	4
22	23	191	197	0	1,500	101	50	9	0	0	141	192	1	-5
23	24	174	183	0	1,500	101	0	9	0	0	83	184	10	1

REFRESH

PT	HE	Pending Adj Schedule	Adj Resource	Adjusted Hourly	Adjusted 4Cast	BHCE DA Load	Diff from DA Load	NEW LOAD	AVG LOAD	BHCE Imbalance	BHCE Schedule	NEW Schedule	BHCE RT DMR
24	1		179	18	1	174	-3	179	170	2	-110	-110	85
1	2		164	6	-7	172	1	164	165	-7	-110	-110	84
2	3		164	13	-6	169	5	164	161	0	-120	-120	82
3	4		164	10	-6	168	1	164	162	-3	-119	-119	84
4	5		178	19	6	175	-1	178	166	2	-120	-120	78
5	6		190	15	0	189	5	190	183	6	-35	-35	88
6	7		202	4	-9	208	-4	202	205	-10	15	15	18
7	8		215	9	-3	211	-2	215	212	2	-35	-35	65
8	9		215	5	-2	213	2	215	214	4	-34	-34	62
9	10		212	-3	3	213	4	212	212	3	-37	-37	62
10	11		214	-4	5	211	2	214	214	37	-37	-37	61
11	12		213	-6	7	208	2	213	213	36	-36	-36	63
12	13		206	-11	3	205	2	206	210	10	-10	-10	42
13	14		206	-9	4	204	2	206	209	10	-10	-10	45
14	15		210	-6	8	204	2	210	209	10	-10	-10	46
15	16		213	-1	12	204	3	213	208	11	-11	-11	49
16	17		216	-5	6	215	5	216	216	11	-11	-11	41
17	18		240	-2	9	238	7	240	237	-64	64	64	39





Example of BHCE E-Tag

Time Zone: **MS**

Transaction type: **Normal**

Tag MWh at generator (original / final): **10 / 30**

CA	TP	PSE	POR	POD	SE	Contract	Misc
PNM		PNMMS1	Source: SJ345				No
	PNM	PNMMS1	SJ345	SJ345	PNM		No
		BHPM01					
	CRCM	BHCEM1	SJ345	CCW	WACM		No
	BHCT	BHCEM1	CCW	BHCE	PSCO		No
PSCO		BHCEM1	Sink: BHCE				No

Current Energy and Transmission Profiles
MW (out of)

	Energy	Transmission	
Start Time	11/28/2012 02:00	11/28/2012 02:00	☑ MW ☑ Reservation ☑ Trans Total
Stop Time	11/29/2012 00:00	11/29/2012 00:00	Enter

Date	Start	Stop	Gen	PNM			CRCM					BHCT			Ramp Dur.	
			MW	Trans	GF 7-F PNMMS1	MW	Trans	77812862 2-NH BHCEM1	77812814 2-NH BHCEM1	77813008 2-NH BHCEM1	MW	Trans	BH CA-CE 8N 6-NN BHCEM1	MW	Start	Stop
Wed 11/28	02:00	03:00	10	10	10	10	10	10			10	10	10	10		
Wed 11/28	03:00	04:00	10	10	10	10	10	0	10		10	10	10	10		
Wed 11/28	04:00	05:00	10	10	10	10	10	0	0	10	10	10	10	10		
Wed 11/28	23:00	00:00	0	0	0	0	0	0			0	0	0	0		
Display MWH Total:			30	30	30	30	30	10	10	10	30	30	30	30		

BHP/CLFP Generation Pool

Production Cost Modeling

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Agenda

- Modeling Approach
- Load Forecast
- Production Cost Modeling
- Modeling Assumptions
- Scenarios
- Next Steps

Modeling Approach

- Evaluate Three Models
  - BHP System
  - CLFP System
  - Combined BHP and CLFP System

- Planning Period
  - Short term – 5 year
  - Long Term – 20 years

Production Cost Modeling

- Load Forecast
- Modeling Assumptions
- Scenarios

Load Forecast

- Analysis uses historical load data and projected new loads
  - Trend historical data
  - Identify potential large load customer load additions for next 5 years

- Energy and Peak Demand Growth Assumptions from recent IRP
  - BHP: Peak Demand Growth 1.0%, Energy Growth 1.0%
  - CLFP: Peak Demand Growth 1.5%, Energy Growth 1.5%

- BHP Load Forecast includes City of Gillette and City of Sheridan Load

Load Forecast

- DSM assumptions
  - Both BHP and CLFP have state regulatory approved DSM programs
  - Assume program goals will be achieved

- Reserve Margin – 15%

Load and Resource Balance Assumptions

- Ben French Steam unit operation suspended September 1, 2012
- Neil Simpson 1 unit retired March 1, 2014
- BH Wyoming 65 MW ownership of Wygen 1 anticipated to be sold to CLFP October 1, 2014
- Cheyenne Prairie Generation Station comes on-line October 1, 2014

Modeling Assumptions

- Existing Unit Fixed and Variable O & M Costs
- Maintenance outages, forced outage rate
- Fuel Pricing –
  - Coal pricing based on contracts
  - Natural Gas price forecast based on NYMEX plus adders
  - Diesel Fuel pricing based on Ventyx's Fall 2012 Reference Case
- Existing Contracts

Colstrip	MDU – Sheridan	CLFP Put
MEAN	City of Gillette	Wind PPAs

Modeling Assumptions

- BHP Economy Energy purchases
  - Allow to purchase up to 150 MW
  - Use adjusted WY Market Area forecast for pricing

- CLFP Economy Energy purchases
  - Allow to purchase up to 150 MW
  - Use adjusted CO East Market Area forecast for pricing

Modeling Assumptions

- Forward Seasonal Capacity Purchases
  - Capacity Purchases for months where a capacity deficit is expected based on Load and Resource Balance.
  - BHP Forward Seasonal Capacity Purchases
    - Seasonal capacity for BHP's 2013 summer peak was purchased in early 2012
    - Price for 2014 through end of planning period based on 2013 purchase price plus 3% annual escalation
  - CLFP Forward Capacity Purchases
    - Price based on WECC Spring 2012 Reference Case AZ-PV market plus 10% premium

Modeling Assumptions

- Marketing Optimization (Sales)
  - Markets are modeled that represent the various markets that BHP sells energy into
  - Pricing for each market is based on a combination of Ventyx's short-term and long-term forecasts
  - Only model sales from energy generated by company-owned generating units

- Future Resources
  - Use Capacity Expansion Plans from BHP and CLFP 2011 IRPs

Scenarios

- High Load and Low Load
- High Gas and Low Gas Cost
- High Coal Cost
- Environmental
  - CO_2 tax pricing and timing from Ventyx's Fall 2012 Reference Case
  - Assumes tax is implemented in 2015
- Addition of a Capacity Sharing Agreement

Next Steps

- Analysis
  - Complete Production Cost Modeling
  - Evaluation of Alternatives to a Generation Pool
    - Merge utilities into one entity
    - Merge generation assets into one company and allocate costs to utilities
    - Continue current operation utilizing existing agreements but with the addition of a Capacity Sharing Agreement
    - Joint Planning Agreement

Next Steps

- Legal Review
  - State and Federal Regulatory Considerations
- Report Study Findings – September 30, 2013

Questions

Wind Resources

- Happy Jack Wind PPA - 29.4 MW
  - BHP has contract for half of output
  - CLFP has contract for half of output
- Silver Sage Wind PPA – 30 MW
  - BHP has contract for 2/3 of output
  - CLFP has contract for 1/3 of output
- Typical average capacity factor – 31.6%
- Capacity Value to be counted for Reserve Margin – 10%

Meeting Notes – December 5 and 6, 2012
2828 Plant Street, Suite B, Rapid City, SD

Attendees:

Kyle White, Todd Brink, Amanda Thames, Lisa Seaman, Brent Voorhees, Mike Theis, Andy Butcher, Dory Batka, Eric Scherr, Bryce Freeman (WY Office of Consumer Advocate), Denise Parrish (WY Office of Consumer Advocate), Jon Thurber (SDPUC Analyst), Randy Falkenberg (BH II - RFI Consulting, Inc.), Drew Moratzka (BH II - Mackall, Crounse & Moore, PLC)

Wednesday, December 5, 2012

- Generation Dispatch and Power Marketing Tour and Presentation
  - Dory and Andy presented detailed information about the operation of the Generation Dispatch and Power Marketing function
  - Presentation file - GDPM BHP CLFP Gen Pool Tour Dec 2012.ppt
  - Dory and Andy conducted a tour of the Generation Dispatch and Power Marketing Area

Thursday, December 6, 2012

- Generation Pool Modeling Discussion
  - Modeling Approach discussion
    - Discussed completing four Base models
      - BHP standalone
      - CLFP standalone
      - A model that captures the benefit of a capacity sharing and joint planning agreement
      - Combined BHP and CLFP system
    - Discussed study planning period
      - 5 year short-term period
      - 20 year long-term period
      - Start date of study will be Jan 1, 2015
    - Discussed scenarios and sensitivity analysis
      - Reviewed the typical scenarios that will be considered – high and low load, high and low gas, high coal cost and environmental
      - Discussed a scenario that shows the impact of the loss of the Sheridan load above the Wygen 3 ownership (see further notes in Load Forecast section)
      - Further discussion and determination of specific scenario analysis will be discussed and decided at future meetings based on outcome of base runs.
    - Discussed evaluation of modeling results

        - Modeling will capture operational benefits and provide a dispatch analysis
        - Initial evaluation will include comparison of the net present value of the base model that captures the benefits of capacity sharing and joint planning to the sum of the BHP standalone and CLFP standalone models.
        - Concern was expressed if the modeling results will allow us to determine the appropriate allocation of savings to each utility.

- Load Forecast
  - Reviewed the trending methodology that we have used in recent ERPs
    - Annual growth rate is calculated by trending historical data
    - Include identified large customer load additions for first 5 years of forecast
    - For the Generation Pool study we intend to use the Energy and Peak Demand Growth Assumptions from recent IRP
      - BHP: Peak Demand Growth 1.0%, Energy Growth 1.0%
      - CLFP: Peak Demand Growth 1.5%, Energy Growth 1.5%
  - BHP Load Forecast includes City of Gillette and City of Sheridan Load
    - Discussed excluding the Sheridan load above their 25 MW ownership of Wygen III in the load forecast. We assume that all other contracts expire based on terms of contract so we discussed why the expectation for this contract would be any different. Discussed modeling the loss of this load as a scenario.
  - DSM Assumptions
    - Discussed the current DSM program in Cheyenne.
  - Reserve Margin
    - Discussed and agreed to a 15% reserve margin for this study.
  - Curtailable Loads
    - Question was asked if either system has any curtailable loads. BHP has a small amount of curtailable load but not a true interruptible load therefore we will not include the interruptible load in the load and resource balance.
- Modeling Assumptions
  - Discussed sources for various forecasts that will be used in the modeling
    - Natural gas price forecast from BH Gas Services Dept. It was requested that we compare the basis for the Gas Dept forecast (Nymex) to Ventyx's forecast for Nymex
    - Forward Capacity Purchases – discussed the markets that GDPM purchases firm energy from. For the combined system analysis we will assume that the firm energy is purchased from the least expensive market.
    - Discussed using Ventyx's Fall 2012 Reference Case for fuel and energy prices rather than Spring 2013 Reference Case because Spring case will not be released until late May or early June 2013.
- Discussed Generation Pool Alternatives

    - Merge utilities into one entity
    - Merge generation assets into one company and allocate costs to utilities
    - Continue current operation with addition of a Capacity Sharing Agreement and Joint Planning Agreement
- Next Steps
    - Confidentiality Agreement – work with stakeholders to complete an agreement.
    - Define and gather assumption data and compile in a brief report for review by all stakeholders.
    - Determine cost for Ventyx to complete modeling
    - Complete outline of potential legal, regulatory and financial issues for each of the Generation Pool Alternatives and how best to evaluate the impact of these issues.
    - Complete modeling and evaluation of savings/costs of generation pool (BHP standalone, CLFP standalone, model that captures the benefit of a capacity sharing and joint planning agreement)
    - Begin drafting Generation Pool Study report
        - Complete outline of report
        - Document what has been completed to date (i.e. educational meetings)
- Schedule
    - January 4, 2013 – BH internal meeting to discuss the issues for each of the three Generation Pool options for development into an outline that documents the legal, accounting, regulatory and tax issues.
    - January 17, 2013 – BH internal meeting to review and discuss modeling assumption data
    - January 24, 2013 – Stakeholder meeting to review and discuss modeling assumption data
    - February 22, 2013 – Stakeholder meeting to review outline of potential legal, regulatory and financial issues for each of the Generation Pool Alternatives and how best to evaluate the impact of these issues.
    - April 1, 2013 - Complete modeling and evaluation of results
    - April 11, 2013 – Stakeholder meeting to review modeling results, discuss if further scenario modeling is necessary.
    - August 1, 2013 – First draft of Generation Pool Study circulated internally.
    - August 30, 2013 – Circulate draft of Generation Pool Study to stakeholders.
    - September 30, 2013 – Generation Pool Study filed with WY PSC and WY OCA.

BHP & CLFP Generation Pool Study

Meeting Agenda **May 30, 2013 10:00 am**

10:00 am Welcome and Introductions

10:15 Generation Pool Modeling

1. Modeling Approach
    a. BHP standalone
    b. CLFP standalone
    c. A model that captures the benefit of a capacity sharing and joint planning agreement
    d. Combined BHP and CLFP system
2. Study Planning Period
    a. 5 year short-term period
    b. 20 year long-term period
    c. Start date of study will be Jan 1, 2015
3. Scenarios and Sensitivity analysis
    a. Scenarios that will be considered first – high and low load
    b. Review results and determine if further scenarios are necessary
4. Modeling Assumptions
    a. Load Forecast
        i. Growth Assumptions from recent IRP
            1. BHP: Peak Demand Growth 1.0%, Energy Growth 1.0%
            2. CLFP: Peak Demand Growth 1.5%, Energy Growth 1.5%
    b. DSM Assumptions
    c. Reserve Margin - 15
    d. Fuel and Electric Price Forecasts
        i. Use Ventyx's Fall 2012 Reference Case
    e. Future Resource Capital Costs and Performance Parameters

12:00 Break for Lunch

12:30 Generation Pool Alternatives

1. Continue current operation with addition of a Capacity Sharing Agreement and Joint Planning Agreement
2. Merge generation assets into one company and allocate costs to utilities
3. Merge utilities into one entity
4. Significant Legal, Regulatory, Tax and Operational Issues related to each of the Generation Pool Alternatives – Attached outline is a preliminary list of issues and analysis that need to be completed
5. Deliverables and Timeline
    a. Production Cost Modeling
        i. Preliminary Production Cost Modeling results – July 31
        ii. Determination of additional scenarios – July 31
        iii. Final Production Cost Modeling results – August 30

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b. Legal, Financial and Regulatory review and analysis of three Generation Pool alternatives
    i. Analysis results – July 2, July 31
c. Draft Generation Pool Report – June, July and August
    i. Generation Pool Report outline – July 2
    ii. Preliminary Generation Pool report – July 15, August 15

6. Next Meetings
    a. July 2, 2013 – Conference call to review Generation Pool Report Outline and review Generation Pool alternative analysis results
    b. July 31, 2013 – Conference call to review preliminary modeling results, discuss further scenarios and review Generation Pool alternative analysis results
    c. August 12, 2013 – Conference call to review preliminary Generation Pool Study report
    d. September 9, 2013 – Conference call to review draft Generation Pool Study

BHP/CLFP Generation Pool

Stakeholder Meeting

May 30, 2013

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Agenda

- Modeling Approach
- Modeling Assumptions
- Generation Pool Alternatives
- Timeline and Deliverables

Modeling Approach

- Evaluate Three Models
  - BHP System
  - CLFP System
  - Combined BHP and CLFP System
- Scenarios
  - High Load, Low Load, Step Load
  - Evaluate results and determine if further scenarios are warranted
- Planning Period
  - Short term – 5 year
  - Long Term – 20 years

Load Forecast

- Analysis uses historical load data and projected new loads
  - Trend historical data
  - Identify potential large load customer load additions for next 5 years

- Energy and Peak Demand Growth Assumptions from recent IRP
  - BHP: Peak Demand Growth 1.0%, Energy Growth 1.0%
  - CLFP: Peak Demand Growth 1.5%, Energy Growth 1.5%

- BHP Load Forecast includes City of Gillette and City of Sheridan Load

Load Forecast

- DSM assumptions
  - Both BHP and CLFP have state regulatory approved DSM programs
  - Assume program goals will be achieved

- Reserve Margin – 15%

Load and Resource Balance Assumptions

- Ben French Steam unit operation suspended September 1, 2012
- Neil Simpson 1 unit retired March 1, 2014
- BH Wyoming's 65 MW ownership of Wygen 1 anticipated to be sold to Cheyenne Light October 1, 2014
- Cheyenne Prairie Generating Station comes on-line October 1, 2014

Modeling Assumptions

- Existing Unit Fixed and Variable O & M Costs
- Maintenance outages, forced outage rate
- Fuel Pricing –
  - Coal pricing based on contracts
  - Natural gas and diesel fuel price forecast based on Ventyx's Fall 2012 Reference Case
  - Natural gas price forecast adjusted to include transportation cost
- Existing Contracts

Colstrip	MDU – Sheridan	CLFP Put
MEAN	City of Gillette	Wind PPAs

Modeling Assumptions

- Forward Seasonal Capacity Purchases
  - Capacity Purchases for months where a capacity deficit is expected based on Load and Resource Balance.
  - Cheyenne Light – 6x16, 50 MW
  - BHP – 6x16, 50 MW
  - Price based on WECC Fall 2012 Reference Case AZ-PV market plus 10% premium

Modeling Assumptions

- Future Resources
  - Use the performance parameters and capital costs for future resource additions from BHP and Cheyenne Light IRPs
  - Complete Capacity Expansion modeling for the separate and combined BHP and CLFP systems

Generation Pool Alternatives

- Studying three alternatives
  - Continue current operation utilizing existing agreements but with the addition of a Capacity Sharing Agreement and Joint Planning Agreement
  - Merge generation assets into one company and allocate costs to utilities
  - Merge utilities into one entity

Continue Current Operation

Capacity Sharing and Joint Planning

- Draft Capacity Sharing Agreement
  - Allow BHP and Cheyenne Light to share Planning Reserves
  - Requires FERC approval
- Draft Joint Planning Agreement
  - Future Resource Planning would include joint evaluation of BHP and Cheyenne Light systems
  - Requires State regulatory informational filing

Merge Generation Assets into One Company

- Merge generation assets into one company and allocate costs to utilities
  - Complete a tax-free transfer of assets at-cost to holding company including all contracts (PPAs)
  - Requires FERC approval
  - Requires State regulatory approval

Merge Generation Assets into One Company

- Significant Legal and Regulatory Considerations
  - Determine Ownership Structure of Company
  - Determine if any existing contracts include language that precludes sale or transfer of assets
  - Formulate pricing of capacity and energy to utilities
  - Transfer of tax obligations

Merge Generation Assets into One Company (cont.)

- Significant Operational Considerations
  - Determine how Power Marketing proceeds would be allocated
  - Determine how cost of transmission will be managed
  - Determine if air permits can be transferred
  - Determine how cost of capital additions will be allocated

Merge Generation Assets into One Company (cont.)

- Significant Operational Considerations
  - Determine if fuel supply contracts can be transferred
  - Determine if air permits can be transferred
  - Determine how cost of capital additions and maintenance will be allocated
  - Determine if employee union approval is required

Merge Generation Assets into One Company (cont.)

- Other Significant Considerations
  - Evaluate risk associated with opening existing contracts

Merge BHP and CLFP into One Utility

- Determine all the agreements, contracts, legal entities that would be need to be revised and/or renegotiated to allow for the merger of the two utilities
- Requires FERC Approval
- Requires State Regulatory Approval – SD, MT, WY

Merge BHP and CLFP into One Utility (cont.)

- Significant Considerations
    - All the considerations that were described under the Merge Generation Assets into One Company option
    - Determine how BHP's and CLFP's debt obligations would be consolidated
    - Determine how tariffs, DSM programs, adjustment clauses would be merged

Merge BHP and CLFP into One Utility (cont.)

- Significant Considerations
  - Determine impact on Franchise Agreements
  - Determine how transmission assets and contracts would be managed
  - Determine how to merge employee benefits, union contracts, etc to one utility
  - Determine how Power Marketing would be managed

Next Steps

- Complete Production Cost Modeling
- Legal, Financial and Regulatory review and analysis of three Generation Pool alternatives
- Draft and Review Generation Pool Report
- Review Process

Timeline

Production Cost Modeling
June and July

Legal, Financial and Regulatory review and analysis of three Generation Pool alternatives
June and July

Draft and Review Generation Pool Report
July, August and Sept

Final Generation Pool Report Due September 30, 2013

Deliverables

- Production Cost Modeling
  - Preliminary Production Cost Modeling results – July 31
  - Determination of additional scenarios – July 31
  - Final Production Cost Modeling results – August 30
- Legal, Financial and Regulatory review and analysis of three Generation Pool alternatives
  - Analysis results – July 2, July 31
- Draft Generation Pool Report – June, July and August
  - Generation Pool Report outline – July 2
  - Preliminary Generation Pool report – July 15, August 15

Questions

BHP & CLFP Generation Pool Study

Meeting Notes May 30, 2013 Stakeholder Meeting

Attendees:

In person: Bryce Freeman (WY Office of Consumer Advocate), Brittany Mehlhaff (SDPUC Analyst), Mike Theis, Kyle White, Brent Voorhees, Lisa Seaman, Amanda Thames, Dory Batka, Kenna Hagan,
Phone: Todd Brink, Randy Falkenberg (BH II – RFI Consulting, Inc.)

Discussed the three Generation Pool alternatives that are being considered in the study:

1. Continue current operation with addition of a capacity sharing agreement and joint planning agreement
2. Create a generation holding company that would own the BHP and CLFP generation assets with allocation of the cost of generation to each of the utilities.
3. Merge BHP and CLFP into one utility.

Discussed Generation Pool modeling approach and assumptions

1. Modeling Approach – complete analysis of four models
    a. BHP standalone
    b. CLFP standalone
    c. A model that captures the benefit of a capacity sharing and joint planning agreement
    d. Combined BHP and CLFP system (includes a combined load forecast and generation)
2. Modeling results that will be presented in Generation Pool Study
    a. 20 year net present value of revenue requirements.
    b. Compare system cost of the standalone systems to the combined system on a $/MWh basis.
3. High load, low load and step load scenarios will be completed along with the four base models. After review of these results the stakeholder group will determine if further scenarios are needed such as high and low gas price and carbon tax scenarios.
    a. Because both BHP and CLFP have serious prospects for additional large customer load growth in the short term the Step Load scenario will identify the impacts of these load additions on system cost.
4. Reviewed modeling assumptions and agreed on the following assumptions:
    a. Study Planning Period – 20 year
    b. Study start date for standalone BHP and CLFP systems- Jan 1, 2015, study start date for combined BHP and CLFP system - Jan 1, 2017
        i. Earliest possible year that a combined system would be in-place is 2017; to compare the 20 year NPVRR of the standalone systems to the same 20 year time period for the combined system, the sum of the standalone system costs for 2015 and 2016 will be used as a proxy for the first two years of the combined system costs.
    c. Load Forecast – use the load forecasts that were developed for the BHP and CLFP IRPs.
        i. Growth Assumptions from recently filed CLFP and BHP IRPs
            1. BHP: Peak Demand Growth 1.0%, Energy Growth 1.0%
            2. CLFP: Peak Demand Growth 1.5%, Energy Growth 1.5%
    d. DSM Assumptions – assume that filed CLFP and BHP DSM goals are achieved
    e. Reserve Margin – 15%
    f. Fuel and Electric Price Forecasts
        i. Use Ventyx's Fall 2012 WECC Reference Case
        ii. Forward seasonal capacity purchases—Use Ventyx's WECC Fall 2012 Reference Case AZ-PV (Palo Verde) market plus 10% premium. Purchase 6x16 blocks seasonally as needed based on load forecast.

g. Future Resource Capital Costs and Performance Parameters – use the same assumptions for future resources as used in BHP's and CLFP's most recent IRPs.

Generation Pool Alternatives Discussion

1. Option 1: Continue current operation with addition of a Capacity Sharing Agreement and Joint Planning Agreement
    a. Black Hills has draft Capacity Sharing Agreement that is being reviewed by the Legal Department and will be circulated to stakeholders after Legal review is complete. Next step is to file this agreement with FERC and provide informational filings with the Wyoming PSC and South Dakota PUC.
    b. Terms of Capacity Sharing Agreement—using similar pricing structure as used in BHP's contract with Gillette.
    c. Financial considerations—the implementation of a capacity sharing agreement may have an impact on off-system sales.
    d. Terms of the Joint Planning Agreement—discussed drafting the terms to require that planning be done for each utility as well as jointly depending on the factors that are driving the need for additional generation resources.
    e. Black Hills will draft Joint Planning Agreement and circulated to stakeholders after Legal review is complete. This agreement may need to be filed for informational purposes with the Wyoming PSC and South Dakota PUC.

2. Option 2: Merge generation assets into one holding company and allocate costs to utilities
    a. Significant Legal, Regulatory, Tax and Operational Issues related to each of the Generation Pool Alternatives – Reviewed an outline of issues and analysis that need to be contemplated for this study.
    b. Discussed some of the procedural tasks that would need to be completed to create a Generation Holding Company.
    c. Discussed possible ownership structure of a Generation Holding Company. Decided that option 1 and option 2 discussed below would be considered in the study.
        i. Option 1) Holding company would be partially owned by each utility based on value of contributed assets
        ii. Option 2) Generation Holding Company would be an affiliate of the utilities
        iii. Option 3) Virtual Company where contracts held by new company but assets held by utilities. This option will almost be achieved with the addition of the Capacity Sharing Agreement and the Joint Planning Agreement.
    d. Discussed several other Legal, Regulatory and Operational considerations
        i. Formulate pricing of capacity and energy to utilities (FERC approval required)
        ii. Potential FERC Filings
        iii. Power Marketing Considerations
        iv. Determine the process to transfer existing permits, such as air permits, to generation holding company.
        v. Operational Considerations
    e. Discussed potential areas of risk related to creating a Generation Pool
        i. Determine risk associated with opening existing contracts/permits

3. Option 3: Merge utilities into one entity

   a. It was decided to table the merger option and concentrate on the first two options. The final report will include a description of this option and highlight the challenges in fully analyzing the option.

4. Deliverables and Timeline
   a. Production Cost Modeling
      i. Preliminary Production Cost Modeling results – July 31
      ii. Determination of additional scenarios – July 31
      iii. Final Production Cost Modeling results – August 30
   b. Legal, Financial and Regulatory review and analysis of three Generation Pool alternatives
      i. Analysis results – July 2, July 31
   c. Draft Generation Pool Report – June, July and August
      i. Generation Pool Report outline – July 2
      ii. Preliminary Generation Pool report – July 15, August 15
5. Next Meetings
   a. July 2, 2013 – Conference call to review Generation Pool Report Outline and review Generation Pool alternative analysis results
   b. July 31, 2013 – Conference call to review preliminary PCM modeling results, discuss further scenarios and review Generation Pool alternative analysis results
   c. August 12, 2013 – Conference call to review preliminary Generation Pool Study report
   d. September 9, 2013 – Conference call to review draft Generation Pool Study

Meeting Agenda – July 2, 2013, 2:00 pm – 5:00 pm
Conference Call/Webex

- Cheyenne Light and BHP Busbar Analysis
- Capacity Sharing Agreement
    - Capacity Sharing Agreement Terms
    - Capacity Sharing Analysis
- Next Steps

Meeting information

Topic: BHP/CLFP Generation Pool Study Meeting
Date: Tuesday, July 2, 2013
Time: 3:00 pm, Central Daylight Time (Chicago, GMT-05:00)
Meeting Number: 744 589 647
Meeting Password: (This meeting does not require a password.)

Call-in Information 866-242-5249 Passcode: 3911458

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Black Hills Corporation
Improving life with energy

BHP/CLFP Generation Pool

Stakeholder Meeting

July 2, 2013

Black Hills Corporation

Improving life with energy

Agenda

- Cheyenne Light and BHP Busbar Analysis
- Capacity Sharing Agreement
    - Capacity Sharing Agreement Terms
    - Capacity Sharing Analysis
- Next Steps

Busbar Analysis

- Compared BHP's and Cheyenne Light's annual cost of generation on $/MWh basis (busbar cost)
- Used 2012 as baseline year
- Used most recent IRP capacity expansion results for future resource additions
- Computed busbar cost for each year that resource was added to either BHP or Cheyenne Light generation fleet
- Assumption that base year busbar cost differential would remain consistent thru the planning period
- Updated PPA costs for the years that new facilities were placed into service

Busbar Analysis

Summary of Costs ($/MWh)	BHP	Cheyenne Light	Average System
2012 Modified	$48.15	$56.86	
2012 Wygen I and CT II	$48.15	$57.62	$51.71
2015 Cheyenne Prairie Generating Station	$56.60	$72.45	$62.63
2022 CT 4 (Cheyenne Light resource)	$56.63	$79.20	$65.28
2024 New Coal (BHP resource)	$66.69	$79.34	$70.87
2030 New CTs (36 MW BHP and 36 MW Cheyenne Light resources)	$70.58	$86.53	$75.91

Busbar Analysis

- Cheyenne Light's and BHP's system busbar costs remain significantly different even as new resources are added in the future
- BHP's long-term self build generation model is providing a lower busbar cost
- Cheyenne Light's first rate base generation asset was placed into service in 2008 and will provide long-term benefit in the future
- BHP's customers would be subsidizing Cheyenne Light's customers if generation assets are pooled

Planning Reserve Capacity Agreement

- Allows affiliate utilities to sell capacity to each other when one is unable to satisfy its entire reserve obligation
- Price based on Supplying Party's system cost
- Total cost of energy is paid if capacity is called upon
- Available for short-term contingencies (30 days or less)
- System contingent
- Does not obligate utilities to sell capacity to each other, depending on market or other conditions
- Requires FERC approval

Capacity Sharing Agreement Analysis

- Analyzed Two Scenarios
  - Capacity shortfall due to load growth and unit retirement
  - Capacity shortfall due to short-term unit outage

Capacity Sharing Analysis

- Assumptions
  - Cost structure includes two cost components:
    - Capacity charge - used the Gillette Planning Reserve monthly charge
    - Energy charge - 75% of forward market price, assumed that any needed energy would be purchased in order to avoid calling on capacity
  - Forward Market Pricing - Palo Verde Price
    - Source - Argus US Electricity Forecast
    - June 10, 2013 Forward Markets
  - Hours - 6 days per week, 8 hours per day

Capacity Sharing Analysis

2014	Jan	Feb	Mar	Apr	May	Sep	Oct	Nov	Dec	2014
BHP Capacity Excess/(Deficit)	39	46	76	88	75	44	134	95	54	
Cheyenne Light Capacity Excess/(Deficit) MW	-36	-31	-21	-11	-17	-66	23	8	-3	
Planning Reserve Capacity that can be supplied by BHP	**30**	**29**	**21**	**11**	**17**	**44**			**3**	

CLFP Capacity Cost paid to BHP ($)	$ 74,730	$ 72,239	$ 52,311	$ 27,401	$ 42,347	$109,604	$ -	$ -	$7,473	$386,105
CLFP Energy Cost ($)	$179,820	$154,512	$121,212	$ 64,865	$104,101	$321,098	$ -	$ -	$18,018	$963,626
Total Cost	$254,550	$226,751	$173,523	$ 92,266	$146,448	$430,702	$ -	$ -	$ 25,491	$1,349,731
CLFP Cost to Purchase Firm Energy ($/MW)	$479,520	$412,032	$323,232	$172,973	$277,603	$856,261	$ -	$ -	$ 48,048	$2,569,669
Benefit to Cheyenne Light	**$224,970**	**$185,281**	**$149,709**	**$ 80,707**	**$131,155**	**$425,559**	**$ -**	**$ -**	**$ 22,557**	**$1,219,938**
Benefit to BHP	**$ 74,730**	**$ 72,239**	**$ 52,311**	**$ 27,401**	**$ 42,347**	**$109,604**	**$ -**	**$ -**	**$7,473**	**$386,105**

Capacity Sharing Analysis

- Neil Simpson II has a 2-day outage in March 2014

2-Day Unit Outage Example	**March 2014**
Loss of Neil Simpson II (MW)	-80
Cheyenne Light Excess Capacity (MW)	45
BHP Capacity Cost Paid to CLFP ($) ($3.35/MWh)	$4,824
BHP Energy Cost ($) (Market Price – 10%)	$29,970
Total Cost ($)	$34,794
BHP Cost to Purchase Firm Energy ($)	$53,280
Benefit to BHP ($)	**$18,486**
Benefit to Cheyenne Light	**$4,824**

Capacity Sharing Agreement Benefits

- Provides an economic option for meeting planning reserve requirement rather than purchasing firm energy for short-term contingencies
- Selling party benefits from capacity payment
- Procuring party can purchase Economy Energy to meet energy need
- Agreement does not obligate utilities to sell capacity to each other

Next Steps

- Analysis
  - Complete Production Cost Modeling
  - Continue Evaluation of Generation Pool Alternatives
    - Merge generation assets into one company and allocate costs to utilities
    - Continue current operation utilizing existing agreements but with the addition of a Capacity Sharing Agreement and Joint Planning Agreement

Next Steps

- Draft Report
  - First draft that includes Introduction and Utilities Overview Sections
- Legal Review
  - State and Federal Regulatory Considerations
- Submit Study Findings to WY PSC and SD PUC – September 30, 2013

Questions

BHP & CLFP Generation Pool Study

Meeting Notes – July 2, 2013 Stakeholder Meeting

Attendees:

In person: Kyle White, Todd Brink, Brent Voorhees, Andy Butcher, Dory Batka, Lisa Seaman, Amanda Thames
Phone: Bryce Freeman (WY Office of Consumer Advocate), Denise Parrish (WY Office of Consumer Advocate), Brittany Mehlhaff (SDPUC Analyst), Andrew Moratzka (BH II – RFI Consulting, Inc.), Wendy Moser, Jill Tietjen

Discussed the Cheyenne Light and BHP Busbar Analysis:

1. Reviewed busbar analysis assumptions:
    a. Used the same assumptions for future resources as used in BHP's and CLFP's most recent IRPs
    b. Compared BHP's and CLFP's annual cost of generation on $MWh basis (busbar cost)
    c. Used 2012 as baseline year
        i. Modified to exclude plants that will be retired in 2013 & 2014
        ii. Converted Wygen I to CLFP ownership (rate based resource)
        iii. CT2 PPA would expire
    d. Computed busbar cost for each year that resource was added to either BHP or CLFP generation fleet
    e. Base year busbar cost differential would remain consistent thru the planning period
        i. There will be some inflation cost increase and rate base asset depreciation, so used the same differential that exists today going forward
        ii. Brent will analyze the 5-year Strategic Plan to determine if costs and benefits match each other
    f. Updated PPA costs for the years that new facilities were placed into service
2. Busbar Analysis
    a. CLFP and BHP's system busbar costs remain significantly different even as new resources are added in the future
    b. BHP's customers would be subsidizing CLFP's customers if generation assets are pooled
3. Discussed the results of the busbar analysis and decided to determine BHP and Cheyenne Light's system costs based on the 5-year Strategic Plan. Brent Voorhees to complete this analysis.

Discussed Planning Reserve Capacity Agreement

1. Reviewed the following Agreement assumptions:
    a. Allows affiliate utilities to sell capacity to each other when one is unable to satisfy its entire 15% reserve margin
    b. Prices based on Supplying Party's system cost
    c. Energy cost if called upon is at cost of that supply
    d. Agreement would allow for transactions to cover short-term contingencies (30 days or less)
    e. System contingent

        i. Ability to recall capacity
        ii. 30 day term helps reduce risk for both parties
    f. Does not obligate utilities to sell capacity to each other
        i. Ability to evaluate the market or other conditions
    g. FERC approval is likely to be required
        i. FERC Counsel has begun to engage in this conversation

2. Capacity Sharing Analysis
    a. Reviewed capacity sharing analysis assumptions:
    b. Analyzed Two Scenarios
        i. Capacity shortfall due to load growth and unit retirement
            1. Analysis considers capacity requirements only, and not additional energy need. It is possible there could be additional cost benefits
            2. Biggest opportunity of dual benefits in 2014
                a. After installment of Cheyenne Prairie Generation Station it will change
        ii. Capacity shortfall due to short-term unit outage
            1. Unforeseen 2 day outage assumed
            2. CLFP has excess capacity
            3. Ongoing dual benefits
3. Discussed the benefits of the proposed Capacity Sharing Agreement
    a. Provides an economic option for meeting planning reserve requirement rather than purchasing firm energy for short-term contingencies
    b. Selling party benefits from capacity payment
    c. Procuring party can purchase Economy Energy to meet energy need
    d. Agreement does not obligate utilities to sell capacity to each other

Next Steps

1. Deliverables and Timeline
    a. Continue busbar study analysis and review results prior to moving forward with the merge analysis – July 16
    b. Production Cost Modeling
        i. Preliminary Production Cost Modeling results – July 31
        ii. Determination of additional scenarios – July 31
        iii. Final Production Cost Modeling results – August 30
    c. Legal, Financial and Regulatory review and analysis of three Generation Pool alternatives
        i. Analysis results – July 31
    d. Draft Generation Pool Report – July and August
        i. Preliminary Generation Pool report – July 15, August 15
        ii. Submit final findings to WY and SD – September 30

2. Next Meetings

a. July 16, 2013 – Conference call to review assumption that the base year busbar cost differential would remain consistent through the planning period
b. July 31, 2013 - to review preliminary PCM modeling results, discuss further scenarios and review Generation Pool alternative analysis results
c. August 12, 2013 – Conference call to review preliminary Generation Pool Study report
d. September 9, 2013 – Conference call to review draft Generation Pool Study

BHP/CLFP Generation Pool

Stakeholder Meeting

July 31, 2013

Black Hills Corporation

Improving life with energy

Agenda

- Cheyenne Light and BHP System Cost Analysis
- Capacity Expansion and Production Cost Modeling Results
- Next Steps

System Cost Analysis
Strategic Plan Assumptions

- System Cost analysis distributed July 24, 2013 compared BHP's and Cheyenne Light's system cost on a $/MWh basis based on Strategic Plan Assumptions
  - Includes owned, contracted and short-term purchased resources

System Cost Analysis

2013-2017 Strategic Plan

Summary of Costs ($/MWh)	BHP	Cheyenne Light	Average System
2013	$44.91	$51.74	$47.33
2014	$48.92	$60.00	$52.96
2015	$53.78	$68.01	$59.18
2016	$55.96	$69.78	$61.22
2017	$55.50	$68.20	$60.34

System Cost Analysis

- BHP's average system cost is lower than CLFP's average system cost
  - BHP's long-term self build generation model is providing a lower system cost
  - Vintage of BHP's resources is primary cause of difference in average system cost

Modeling Assumptions

- Load Forecast
- Price Forecasts
- Future Resource Options

Modeling Results
Base Plan

20 Year Net Present Value of Revenue Requirements (millions)	
BHP Standalone	$1,814.54
CLFP Standalone	$1,096.07
BHP plus CLFP	$2,910.61
BHP - CLFP Combined	$2,732.68
Benefit of Pooling	$177.93

Modeling Results
High Load, Low Load and Step Load Scenarios

20 Year Net Present Value of Revenue Requirements (millions)

	Low Load	High Load	Step Load
BHP Standalone	$1,600.55	$2,025.61	$2,000.66
CLFP Standalone	$1,017.46	1,177.34	$1,447.48
BHP plus CLFP	$2,618.01	$3,202.95	$3,448.14
BHP/CLFP Combined	$2,506.58	$3,033.14	$3,228.92
Benefit of Pooling	$111.43	$169.81	$219.22

Next Steps

- Analysis
  - Further Analysis
  - Continue Evaluation of Generation Pool Alternatives
    - Merge generation assets into one company and allocate costs to utilities
    - Continue current operation utilizing existing agreements but with the addition of a Capacity Sharing Agreement and Joint Planning Agreement

Next Steps

- Draft Report
  - First draft that includes Introduction and Utilities Overview Sections
- Legal Review
  - State and Federal Regulatory Considerations
- Submit Study Findings to WY PSC and SD PUC – September 30, 2013

Questions

BHP & CLFP Generation Pool Study

Meeting Notes – July 31, 2013 Stakeholder Meeting

Attendees:

In person: Kyle White, Brent Voorhees, Andy Butcher, Dory Batka, Lisa Seaman, Amanda Thames, Mike Theis, Bryce Freeman (WY Office of Consumer Advocate), Denise Parrish (WY Office of Consumer Advocate), Brittany Mehlhaff (SDPUC Analyst)
Phone: Randy Falkenburg (BH II – RFI Consulting, Inc.), Todd Brink, Jill Tietjen, Diane Crockett

Discussed the Cheyenne Light and BHP System Cost Analysis:

1. Reviewed strategic plan assumptions for system cost analysis:
    a. Strategic plan $/MWh cost includes busbar, owned, contracted and short term purchased resources
2. System Cost Analysis
    a. BHP's average system cost is lower than CLFP's average system cost

Discussed Modeling Results

1. Reviewed modeling assumptions:
    a. Load Forecasts
        i. Used each utilities load and resource balance from the corresponding IRPs
            1. Includes DSM, reserve margin, resources, and purchases
                a. DSM assumed in IRP would not materially change load forecast, but could flatten growth rates if achieved
                b. Approved DSM was modeled and extended through remaining study years and not escalated
        ii. 3 separate databases were used
            1. CLFP Standalone
            2. BHP Standalone
            3. Combined System
                a. Each standalone's hourly load shape was added together
                b. Peaked in August, peak was lower than combined standalone peaks
2. Discussed modeling results of base plans and scenarios
    a. Base Plan
        i. Showed benefit of pooling over course of 20 years
            1. Peak diversity contributes to benefit
        ii. BHP builds stayed mostly consistent with IRP
        iii. CLFP builds stayed fairly consistent with IRP with builds moving up
        iv. Combined 125 MW seasonal capacity and coincident peak drives delay of builds
    b. High Load, Low Load, and Step Load Scenarios
        i. Benefit of pooling over course of 20 years
            1. Low load demonstrates least amount of cost savings
            2. Step load demonstrates greatest amount of cost savings

Next Steps

1. Deliverables and Timeline

   a. Additional Production Cost Modeling to be completed to evaluate the benefits of a Planning Reserve Capacity Agreement, the Economy Energy Agreement and joint planning.
      i. Review results at August 20, 2013 stakeholder meeting
   b. Complete evaluation of the potential impact of environmental regulation. Discussed reviewing the results of the Environmental Scenarios from the BHP and Cheyenne Light IRPs.
   c. Capacity Sharing Agreement
      i. FERC counsel to review
      ii. Provide Agreement for group's review prior to FERC filing
   d. Joint Planning Agreement
      i. Develop on outline for a Joint Planning Agreement
   e. Draft Generation Pool Report
      i. Preliminary Generation Pool report –August 20
      ii. Submit final findings to WY and SD – September 30
2. Next Meetings
   a. August 20, 2013 – Conference call to review preliminary Generation Pool Study report, Production Cost Modeling Results, and Environmental Indications
   b. September 9, 2013 – Conference call to review draft Generation Pool Study

BHP/CLFP Generation Pool

Stakeholder Meeting

August 20, 2013

Black Hills Corporation

Improving life with energy

Agenda

- Planning Reserve Capacity and Joint Resource Planning Benefits
- Economy Energy Agreement Benefits
- Joint Resource Planning Process
- Next Steps

Planning Reserve Capacity Agreement Benefits

- Provides an economic option for meeting planning reserve requirement rather than purchasing firm energy for short-term contingencies
- Selling party benefits from capacity payment
- Procuring party can purchase Economy Energy to meet energy need
- Agreement does not obligate utilities to sell capacity to each other

Planning Reserve Capacity and Joint Planning Modeling

- Compared the PVRR of the following models to determine savings from a Planning Reserve Capacity Agreement and Joint Planning
  - Sum of the PVRRs of standalone BHP and CLFP systems
  - PVRR of BHP/CLFP combined system that maintains separate load forecasts but solve for a combined reserve margin

Modeling Results

Planning Reserve Capacity Agreement and Joint Planning Savings

20 Year Net Present Value of Revenue Requirements (millions)	
BHP Standalone	$1,814.54
CLFP Standalone	$1,096.07
BHP plus CLFP	$2,910.61
Share Planning Reserve and Joint Planning	$2,775.32
Benefits	$135.29

Economy Energy Agreement Benefits

- Allows the parties to voluntarily sell and buy economy energy services among themselves
- Transaction is allowed when purchasing party is unable to procure reliable energy from another supplier at a lower price

Economy Energy Agreement Modeling

- Compared the PVRR of the purchase power expense, fuel expense and variable O&M expense of the following models:
  - Sum of the PVRRs of standalone BHP and CLFP systems
  - Combined BHP and CLFP system that includes the resource additions from the standalone plans

Modeling Results

Economy Energy Service Agreement

20 Year Net Present Value of Revenue Requirements Market Purchase Power, Fuel Expense, Variable O&M (millions)	
BHP Standalone	$810.31
CLFP Standalone	$385.79
BHP plus CLFP	$1,196.10
BHP - CLFP Combined	$1,179.91
Benefit of Economy Energy Service Agreement	$16.19

Modeling Results
Savings from Agreements

20 Year Net Present Value of Revenue Requirements (millions)	
Planning Reserve Capacity Agreement and Joint Planning	$135.29
Economy Energy Service Agreement	$16.19
Benefit of Agreements	$151.48
BHP-CLFP Combined System	$ 177.93
Potential Generation Pool Differential	$26.45

Joint Resource Planning

- Recognize that Joint Resource Planning should provide economic benefits to customers
- Joint Resource Planning not appropriate under all circumstances
- Develop process to complete preliminary evaluation prior to beginning a Resource Plan

Joint Resource Planning Process

- Revise load forecasting techniques
  - Use customer class data
  - Use weather normalization
- Complete preliminary evaluation of future resource expansion plans to determine if joint or independent resource plans are appropriate.
  - In-house capacity expansion and production cost modeling

Next Steps

- Continue to develop study report
- Legal Review
  - State and Federal Regulatory Considerations
- Submit Study Findings to WY PSC and SD PUC – September 30, 2013

Questions

BHP & CLFP Generation Pool Study

Meeting Notes – August 20 Stakeholder Meeting

Attendees:

In person: Kyle White, Brent Voorhees, Andy Butcher, Dory Batka, Lisa Seaman, Amanda Thames, Kenna Hagan

Phone: Bryce Freeman (WY Office of Consumer Advocate), Denise Parrish (WY Office of Consumer Advocate), Brittany Mehlhaff (SDPUC Analyst), Randy Falkenberg (BH II – RFI Consulting, Inc.), Todd Brink

Discussed the Planning Reserve Capacity and Joint Resource Planning Benefits:

1. Reviewed the benefits of the proposed Planning Reserve Capacity Agreement
2. Reviewed Planning Reserve Capacity and Joint Planning Modeling
   a. Compared the PVRR of the following models to determine savings from a Planning Reserve Capacity Agreement and Joint Planning
      i. Sum of the PVRRs of standalone BHP and CLFP systems
      ii. BHP/CLFP combined system that maintains separate load forecasts but solve for a combined reserve margin and adds resources for a combined system.
      iii. Results showed that over a 20 year period the addition of a Planning Reserve Capacity Agreement and joint planning could save the utilities' customers approximately $135 million.

Discussed Economy Energy Agreement Benefits

1. Reviewed Economy Energy Agreement modeling assumptions and results
   a. Compared the PVRR of the purchase power expense, fuel expense, and variable O&M expense of the following models:
      i. Sum of the PVRRs of standalone BHP and CLFP systems
      ii. Combined BHP and CLFP system that includes the resource additions from the standalone plans
      iii. Results showed that over a 20 year period the Economy Energy Agreement could save the utilities' customers approximately $16 million.

Discussed Savings from Agreements

1. Results showed that over a 20 year period the Economy Energy Agreement, the proposed Planning Reserve Capacity Agreement and joint planning could save the utilities' customers a total of approximately $151 million.
   a. Planning Reserve Capacity Agreement and Joint Planning savings $135.29 million
   b. Economy Energy Service Agreement savings $16.19 million
2. Modeling results showed that a BHP-CLFP Combined System could save customers approximately $177.93 million over a twenty year period.
3. Savings differential between a Generation Pool and continued current operation with the addition of a Planning Reserve Capacity Agreement and future joint planning is approximately $26.45 million

Meeting Notes – August 20 Stakeholder Meeting

Discussed the proposed Joint Resource Planning Process rather than drafting a formal Joint Planning Agreement

1. Joint Resource Planning is not necessarily appropriate under all circumstances and the group discussed some examples where joint planning would not be beneficial to both parties.
2. Discussed the implementation of principles that would be used by BHP and Cheyenne Light as they complete resource planning in the future. Asked the stakeholders to provide input and suggestions to consider as BHP and Cheyenne Light draft these principles. Discussed the difficulty in drafting principles that will take into account all possible scenarios.

Reviewed IRP Environmental Analysis

- a. Compared PVRRs from each utility's IRP for the preferred plan and environmental scenarios
- b. Additional discussion to be continued at August 26 meeting

Next Steps

1. Deliverables and Timeline
    - a. Capacity Sharing Agreement
        - i. FERC counsel to review
        - ii. Provide Agreement for group's review prior to FERC filing
        - iii. File with FERC
    - b. Draft Generation Pool Report
        - i. Continue to draft preliminary Generation Pool report
        - ii. Submit final findings to WY and SD – September 30
4. Next Meetings
    - a. August 26, 2013 – Conference call to review
        - i. Preliminary Generation Pool Study report
        - ii. Production Cost Modeling Results
            1. Planning Reserve Capacity and Resource Planning
            2. Economy Energy Agreement
        - iii. Environmental IRP Assumption Differentials
        - iv. Additional questions from previous analyses
    - b. September 3, 2013 – Conference call to review draft Generation Pool Study Report
    - c. September 20, 2013 - Conference call to review Generation Pool Study Report

Meeting Agenda – August 26, 2013, 1:00 pm – 3:00 pm

- This meeting is intended to provide time for stakeholders to discuss and ask questions about the analyses that have been completed for the Generation Pool Study. Though we may not discuss all of the analyses that have been completed, I have included below a list of the analyses that have been completed and the names of the results files that have been provided to stakeholders.
  - **Environmental Scenario Analysis** - this analysis used capacity expansion and production cost modeling from the BHP and Cheyenne Light 2011 Integrated Resource Plans to identify the impact of future environmental regulation on BHP's and Cheyenne Light's systems.
    - Results of this analysis are included in the following file:
      - Environmental Scenario Report 8-22-13.doc
  - **Planning Reserve Capacity Agreement and Joint Planning Analysis** - this analysis used capacity expansion and production cost modeling to identify the cost savings from joint planning and the proposed Planning Reserve Capacity Agreement.
    - Results of this analysis are included in the following files:
      - PVRR Results_Planning Reserve Agreement_Joint Planning.xls
  - **Economy Energy Agreement Analysis** - this analysis used capacity expansion and production cost modeling to identify the cost savings from the existing Economy Energy Agreement.
    - Results of this analysis are included in the following files:
      - PVRR Results_Economy Agreement.xls
  - **Combined Dispatch Analysis** – this analysis used capacity expansion and production cost modeling to identify the cost savings from combining the BHP and Cheyenne Light systems
    - Results of this analysis are included in the following files:
      - PVRR Results_BHP_CLFP_Combined.xls
      - Capacity Expansion Builds_BHP-CLFP-Combined.xls
      - Base Load_CLFP & BHP Load and Resouce Balance.xls
  - **5 year Strategic Plan System Cost Analysis** - This analysis compared the system costs of BHP and Cheyenne Light over the 5-year Strategic Planning Period of 2013 through 2017.
    - This analysis is contained in the file
      - Busbar Costs - Generation Pool Study 5 Year Strat Plan - Confidential 7_18_2013.xls
  - **Planning Reserve Capacity Agreement Analysis** – This analyses included two examples that show potential benefits of the proposed Planning Reserve Capacity Agreement:
    - 2014 Load Growth Analysis
    - 2-day Unit Outage Analysis
    - These analyses were contained in the file:
      - Capacity Sharing Analysis Final 7-1-13.xls
  -

- Next Stakeholder Meetings
  - September 3, 1 to 4 pm (MT) Conference Call
  - September 20, 1 to 4 pm (MT) Conference Call

BHP & CLFP Generation Pool Study

Meeting Notes – August 26, 2013 Stakeholder Meeting

Attendees:

In person: Kyle White, Todd Brink, Amanda Thames
Phone: Lisa Seaman, Brent Voorhees, Mike Theis, Wendy Moser, Jill Tietjen, Diane Crockett, Bryce Freeman (WY Office of Consumer Advocate), Denise Parrish (WY Office of Consumer Advocate), Brittany Mehlhaff (SDPUC Analyst)

Discussed the Environmental Scenario Analysis:

1. Used capacity expansion and production cost modeling from the BHP and CLFP 2011 Integrated Resource Plans to identify the impact of future environmental regulation on BHP's and CLFP's systems
    a. Reviewed BHP and CLFP IRP model assumptions
        i. Emission costs
        ii. Natural gas prices
        iii. Market prices
        iv. Modeling process
            1. Completed capacity expansion modeling for each scenario (Preferred Plan and Environmental) first
            2. After build outs are determined, the PVRR costs are calculated using the base case assumptions
    b. Reviewed the analysis
        i. For BHP, the base and environmental scenarios were compared
        ii. For CLFP, the Preferred Plan and environmental scenarios were compared
        iii. Discussed the optimal resource portfolios for each of the scenarios
            1. BHP
                a. 2024 base case adds 100 MW coal
                b. 2024 environmental case adds two 36 MW CT's and 30 MW wind
            2. CLFP
                a. 2018 preferred plan adds 36 MW CT
                b. 2018 environmental case adds 30 MW wind and 2019 adds 36 MW CT
        iv. Discussed the comparison of the PVRR for each scenario
            1. BHP PVRR , environmental scenario with Base case assumptions, is expected to decrease over the 20-year planning period
            2. CLFP PVRR, environmental scenario with Preferred Plan assumptions, is expected to increase over the 20-year planning period
            3. Cost differential between the utilities would remain, and is expected to widen if a carbon tax were implemented as reflected in the environmental scenario

Discussed Planning Reserve Capacity Agreement and Joint Planning Analysis

1. Used capacity expansion and production cost modeling to identify the cost savings from joint planning and the proposed Planning Reserve Capacity Agreement

   a. Modeled 3 plans; BHP standalone, CLFP Standalone and a Combined System with independent company peaks that maintains individual system peaks or zones but requires one reserve margin for the combined system
   b. Individual zone reserve margins allowed to fall below 15%, but system reserve margins must maintain 15%
   c. Analysis demonstrates utilities sharing system planning reserves provides a cost benefit
   d. System build out includes both utilities planning reserve and joint planning difference to be $135 million

Discussed Economy Energy Agreement Analysis

1. Used capacity expansion and production cost modeling to identify the cost savings from the existing Economy Energy Agreement
   a. Modeled 3 plans; BHP standalone, CLFP Standalone and a Combined System with independent company peaks that maintains individual system peaks or zones but requires one reserve margin for the combined system
   b. Ability to share economy energy
      i. Compared market purchase power, fuel expense, variable O&M expenses to determine benefit of this agreement
      ii. Agreement already in place expected to yield $16 million savings over the next 20 years

Discussed Joint Dispatch Analysis

1. Used capacity expansion and production cost modeling to identify the cost savings from combining the BHP and Cheyenne Light systems
   a. Modeled 3 plans; BHP standalone, CLFP Standalone and a Combined System
      i. Combined system peaks, non-coincident peaks resulted in decreased combined system peak
      ii. One planning reserve margin for combined system
   b. Analysis showed approximately $178 million in benefits
      i. Highest savings from all the analyses done
      ii. All other agreements will result in achieving roughly 85% of the potential savings achieved by the combined system
         1. Leaves roughly $20 million in savings left to achieve

5 Year Strategic Plan System Cost Analysis

1. Compared the system costs of BHP and Cheyenne Light over the 5-year Strategic Planning Period of 2013 through 2017

Planning Reserve Capacity Agreement Analysis

1. Included two examples that show potential benefits of the proposed Planning Reserve Capacity Agreement
   a. 2014 Load Growth Analysis

b. 2-day Unit Outage Analysis

Other Topics and Feedback

1. Generation Pool Study Report
    a. Will be used as a reference document in the future
        i. Comments and suggestions welcome

Next Steps

1. Deliverables and Timeline
    a. Review additional carbon cost analysis – Sept 3
        i. Quantify possible future carbon tax costs to BHP and CLFP
            1. Use existing carbon emissions data and Ventyx's forecast for future carbon tax costs
    b. Capacity Sharing Agreement
        i. FERC counsel to review – in final stages
            1. Looking at possibility that this agreement would not require FERC approval
        ii. Provide draft Agreement for group's review prior to FERC filing – goal is next week
    c. Draft Generation Pool Report
        i. Continue to draft preliminary Generation Pool report –September 3
            1. Welcome to send any comments prior to discussion
            2. Brainstorm and send any Joint Planning Principles
    d. Submit final findings to WY and SD – September 30

2. Next Meetings
    a. September 3, 2013 – Conference call to review draft Generation Pool Study Report
    b. September 20, 2013 – Conference call to provide final comments/questions on Draft Generation Pool Study Report

BHP & CLFP Generation Pool Study

Meeting Notes – September 3, 2013 Stakeholder Meeting

Attendees:

Phone: Kyle White, Amanda Thames, Dory Batka, Kenna Hagan, Jill Tietjen, Diane Crockett, Bryce Freeman (WY Office of Consumer Advocate), Denise Parrish (WY Office of Consumer Advocate), Brittany Mehlhaff (SDPUC Analyst), Randy Falkenburg (BH II – RFI Consulting, Inc.)

Discussed the revised Generation Pool modeling results. Diane Crockett explained the issue that she corrected in the modeling and reviewed the new results.

($ millions)	Original	Revised
Combined System Savings	177.93	105.89
Planning Reserve/Joint Planning Savings	135.29	51.4
Economy Energy Agreement Savings	16.19	16.19
Agreement Savings	151.48	67.59
Difference between Savings of a combined system and operation with agreements	26.45	38.3
Per Year (20 years)	1.3225	1.915

Discussed the Generation Pool Report: Stakeholders provided comments and suggestions for the study report.

1. ES-1 and ES-2 bullet points 2 and 4 may be out of the scope of this collaborative
2. Table 3-2 needs clarification that the $1.2 million in savings is for a particular year with a certain set of assumptions
3. Clarify in section 2.1 BHP and Cheyenne Light Resource Planning History
    a. who the resources are for and if there is an order or reference document where the commission expressed concern
    b. If resource planning and modeling conducted for IRPs matches the resources recommended
        i. Consider adding this to joint planning principles
4. Randy will add a footnote or comments surrounding the legal cases mentioned in the 2nd paragraph of section 3.2.2
5. BHC to discuss addition of more details to 3.2.2 Joint Resource Planning bullet point #4
6. Consider how to characterize the high-level numbers that were used in the report for Generation Holdings, Legal and Federal Tax Issues, Regulatory Issues, and the additional staff required for the two new state property tax returns
7. Update Tables 3-6 thru 3-11 with the correct PVRR values.
8. Add clarifying details to section 3.4.5 Analysis regarding the use of base case assumptions in the PVRR difference analysis
    a. Only thing changed is resource portfolio for the environmental case

b. Gas and market prices are reflected in the base case assumptions

9. Consider adding to joint planning principles that the goals is to obtain the maximum amount of benefits including load diversity
    a. Comments
        i. Stakeholders will consider how they would like to provide comments (footnote, letter to commissioner, etc)

Next Steps

1. Deliverables and Timeline
    a. Capacity Sharing Agreement
        i. FERC counsel to review – in final stages
            1. Evaluating if this agreement requires FERC approval
        ii. Provide draft Agreement for group's review prior to FERC filing – goal is next week
        iii. File with FERC if needed
    b. Draft Generation Pool Report
        i. Continue to draft preliminary Generation Pool report –September 20
            1. May incorporate points considered today
            2. Welcome to send additional comments/edits for consideration to Lisa
            3. Redline report to be sent out prior to September 20
        ii. Submit final findings to WY and SD – September 30
2. Next Meetings
    a. September 20, 2013 – Conference call to provide final comments/questions on Draft Generation Pool Study Report

BHP & CLFP Generation Pool Study

Meeting Notes – September 20, 2013 Stakeholder Meeting

Attendees:

Phone: Kyle White, Lisa Seaman, Amanda Thames, Mike Theis, Kenna Hagan, Jill Tietjen, Bryce Freeman (WY Office of Consumer Advocate), Denise Parrish (WY Office of Consumer Advocate), Brittany Mehlhaff (SDPUC Analyst), Randy Falkenburg (BH II – RFI Consulting, Inc.)

Discussed the Generation Pool Report: Stakeholders provided final comments and suggestions for the study report.

1. Would like to see more detail related to how joint resource planning will be conducted in the future including the benefits of load diversity
2. Incorporate submitted cosmetic changes
3. Addressed preference for receiving a hard copy or electronic version of final study to be filed

Next Steps

1. Deliverables and Timeline
    a. Capacity Sharing Agreement
        i. FERC counsel has reviewed – in final stages
            1. Evaluating if this agreement requires FERC approval
        ii. Provide draft Agreement for group's review early next week
        iii. Black Hills will continue to provide updates to group
        iv. File with FERC if needed
    b. Draft Generation Pool Report
        i. Redline Generation Pool report –September 23
            1. May incorporate points considered today
            2. Provide any final comments/questions on Draft Generation Pool Study Report to Lisa
        ii. Submit final report to WY and SD – September 30
2. Next Meetings
    a. No further meetings are scheduled