Exhibit JST-2

Black Hills Power 2011 Integrated Resource Plan

2011-2030 Integrated Resource Plan
for
Black Hills Power

2011

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ES.0 Executive Summary

ES.1 Summary

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

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

The preferred plan meets the objectives of the company to:

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

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

ES.2 Action Plan

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

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

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

ES.3 Company Background

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

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

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

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

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

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

ES.4 The Planning Environment

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

The Environmental Protection Agency (EPA) issued National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial and Institutional Boilers (herein "Area Source Rules"), on March 21, 2011 with an effective date of May 20, 2011. The deadline to comply with these rules is March 21, 2014. This rule provided for hazardous air pollutant-related emission limits and monitoring requirements for area sources of hazardous air pollutants. BHP is evaluating the impact of the rules on its existing generating facilities. The Area Source Rules as issued have a significant impact on our Neil Simpson I, Osage and Ben French coal-fired facilities, which have collectively provided approximately 71 MW summer of summer capacity. The regulation has prompted BHP to perform an engineering evaluation to determine economic viability of continued operations of these units. Based on the evaluations completed, the cost associated with complying with the Area Source Rules and other environmental regulations may lead to retirement of these units prior to March 21, 2014.

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

ES.5 Assumptions

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

ES.6 Demand-Side Management

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

ES.7 Supply-Side Resources

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

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

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

ES.8 Resource Need Assessment

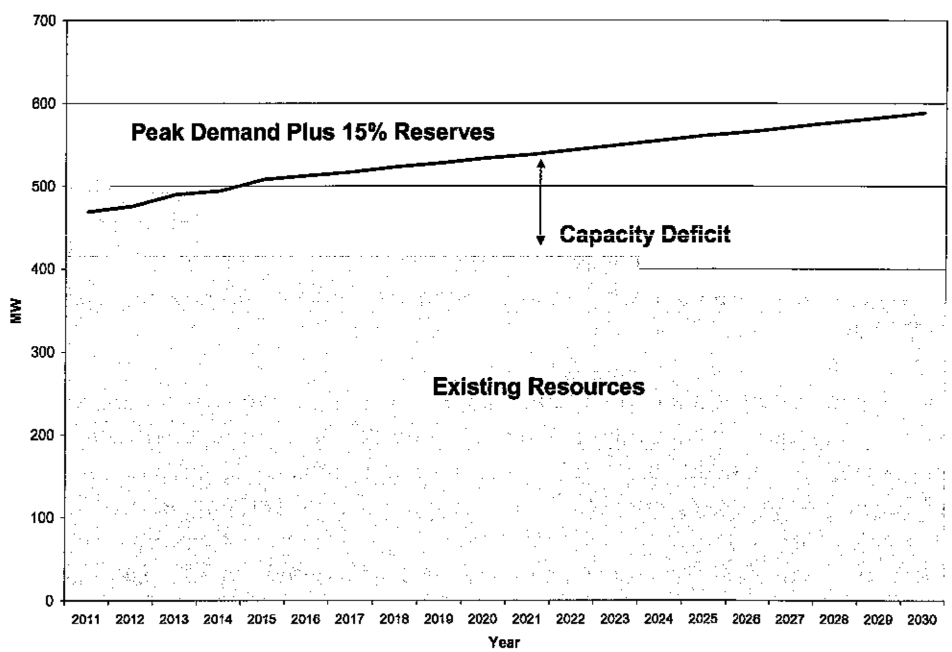
The EPA Area Source Rules have an impact on BHP's Ben French, Neil Simpson 1, and Osage coal-fired generation units. Currently, the Osage units are in cold storage based on economics and are not included as part of BHP's available resources, but Ben French and

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

In addition, the Reserve Capacity Integration Agreement (RCIA) with PacifiCorp terminates in 2012 which results in the effective loss of 28 MW of summer capacity. The PPAs with PacifiCorp, Happy Jack, and Silver Sage all terminate over the planning horizon for a loss of 53.5 MW of accredited capacity.

As resources retire or existing PPAs terminate, other resources will be required to enable BHP to meets its obligations to serve the electricity needs of its customers. The totality of the requirements for new resources, incorporating the need for a minimum planning reserve margin of 15% and reflecting that BHP has no committed resources (resources that are planned and/or under construction but are not currently operational) in its generation portfolio, is shown on Figure ES-1. The capacity deficit in any year is reflected as the distance between the line labeled "Peak Demand Plus 15% Reserves" and the top of the shaded block for "Existing Resources". BHP's capacity deficit in 2014 is approximately 66 MW and reaches approximately 225 MW by the end of the planning horizon.

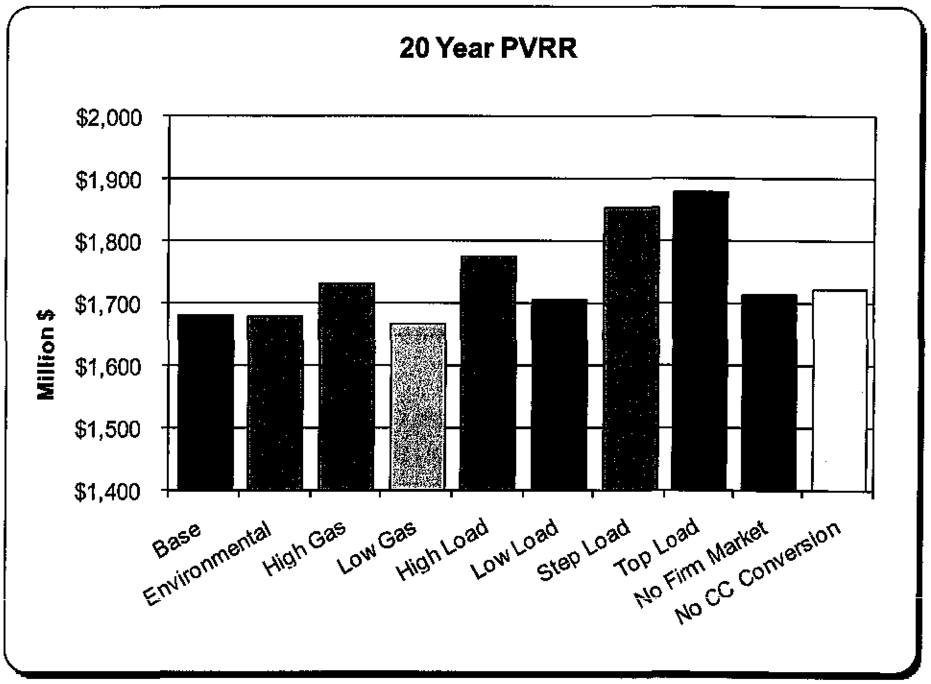
Figure ES-1
Black Hills Power Load and Resource Summary



ES.9 Resource Evaluation

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

Figure ES-2
Deterministic PVRR for Scenarios



ES.10 Risk Analysis

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

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

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

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

Table ES-1
Ranges for Selected Uncertainty Variables

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

Source: Ventyx

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

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

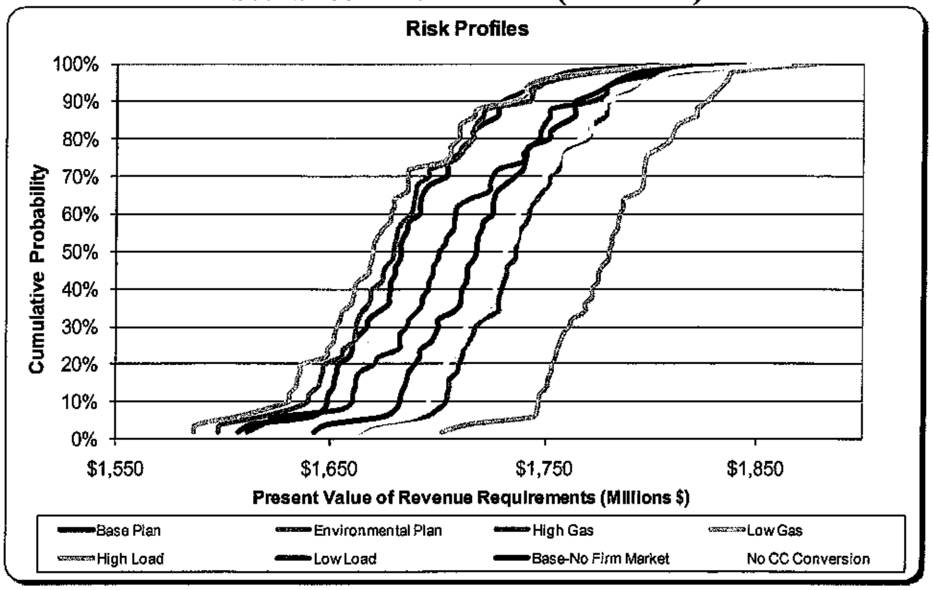
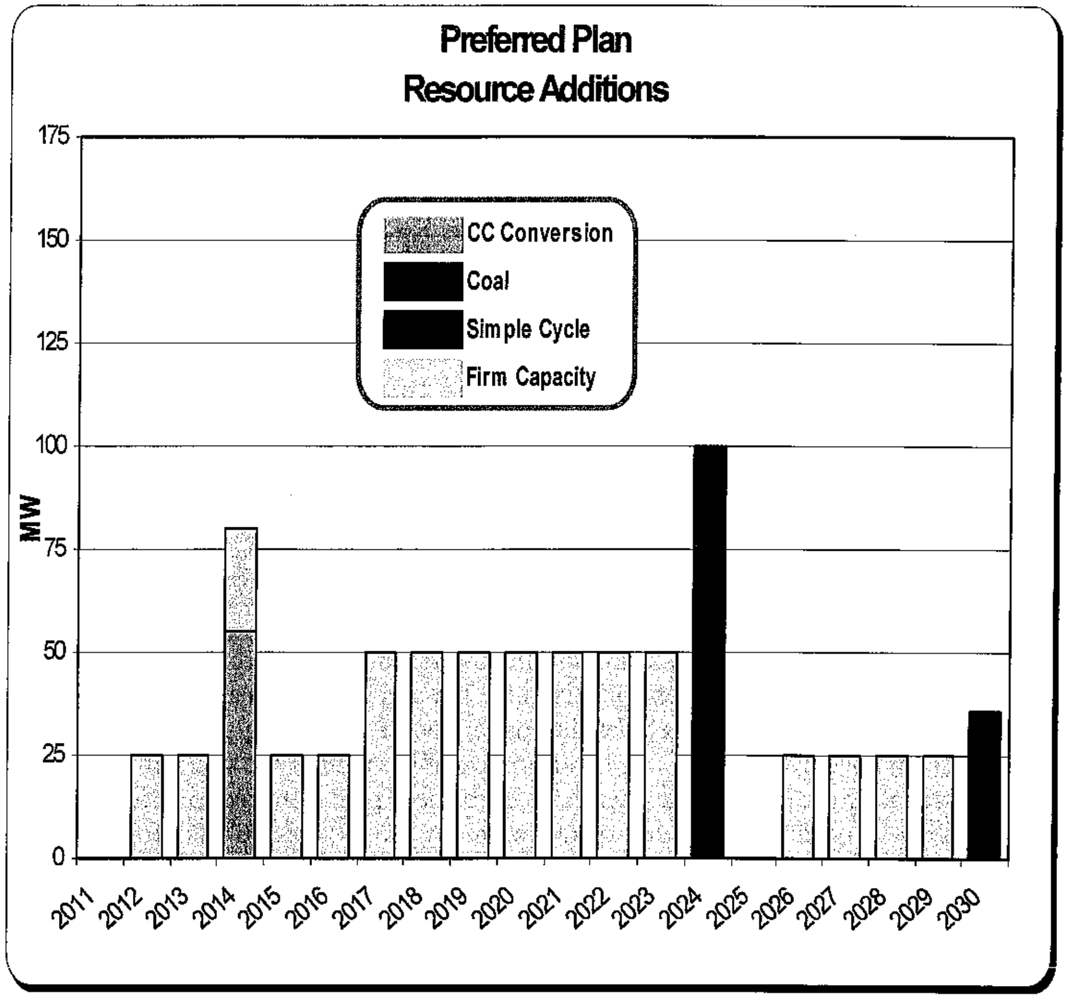


Figure ES-3 shows that with the exception of the low gas and the environmental scenarios, the risk profile for the base plan is to the left and lower than any other case. The base plan resource portfolio includes the conversion of an existing simple cycle gas turbine to a combined cycle unit in 2014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

Figure ES-4



ES.11 Conclusion

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

The preferred plan meets the objectives of the company to:

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

1.0 Introduction

1.1 Background

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

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

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

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

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

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

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

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

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

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

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

the case. Such enactment is exceedingly dependent on politics and the development of laws and public policy in Washington, DC.

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

1.2 Objectives

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

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

The preferred plan meets the objectives of the company to:

- Ensure a reasonable level of price stability for its customers
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1.3 IRP Process

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

2.0 Planning Environment

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

2.1 The Future of Coal-Fired Generation

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

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

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

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

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

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

2.1.1 Climate Change Legislation

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

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

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

2.1.2 Carbon Capture and Sequestration Technologies[2]

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

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

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

2.1.3 Environmental Regulatory Requirements

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

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

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

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

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

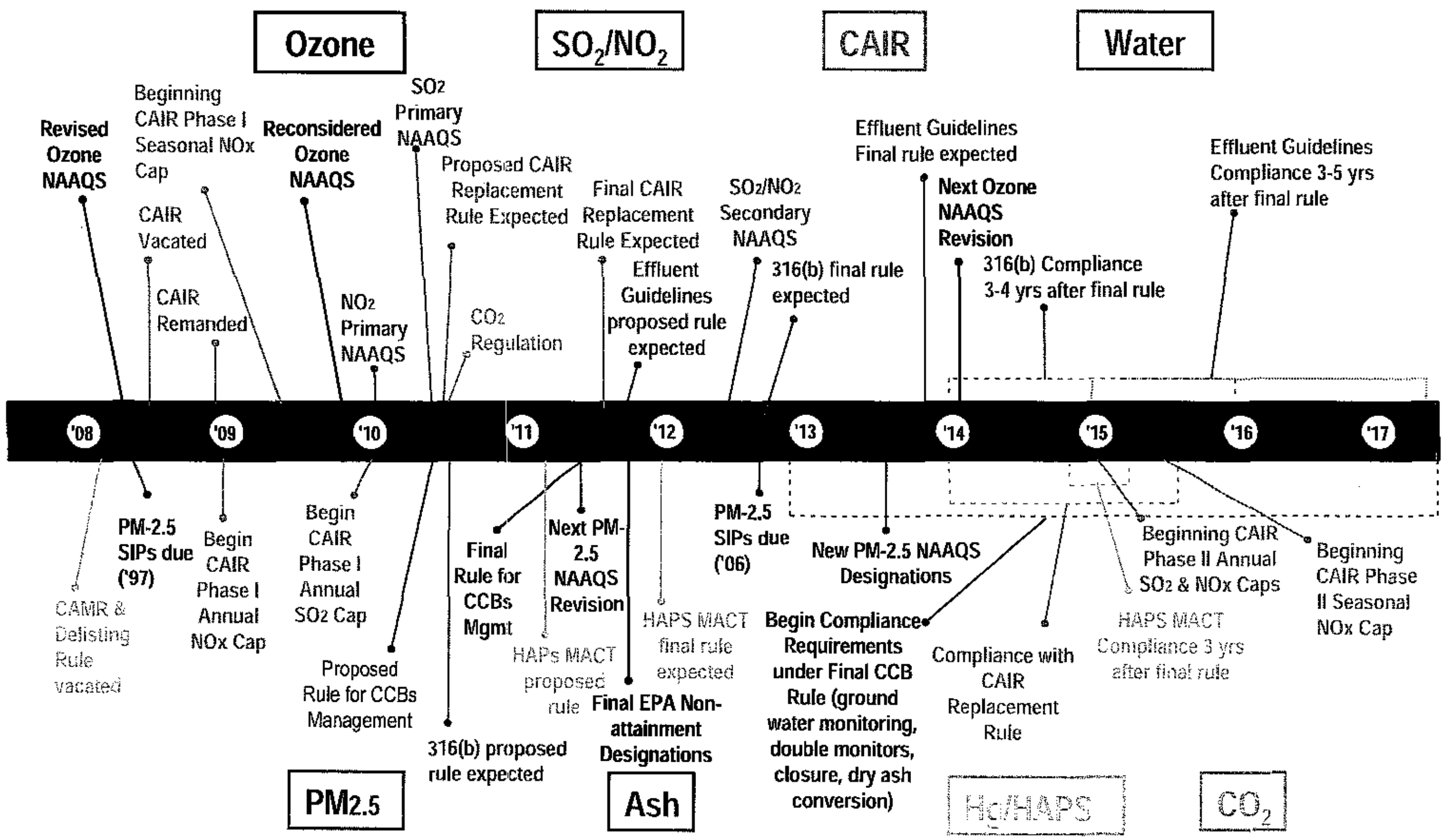
The EPA issued National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial and Institutional Boilers (herein "Area Source Rules"), on March 21, 2011 with an effective date of May 20, 2011. The deadline to comply with these rules is March 21, 2014. This rule provides for hazardous air pollutant-related emission limits and monitoring requirements for area sources of hazardous air pollutants. BHP is evaluating the impact of the rules on its existing generating facilities. The area source rules, as issued, have a significant impact on our Neil Simpson I, Osage and Ben French coal-fired facilities. The regulation has prompted BHP to perform engineering evaluations to determine economic viability of continued operations of these units. In our current opinion, the regulations will lead to retirement of these units within three years of the effective date of the final rule.

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

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

Figure 2-1

Possible Timeline for Environmental Regulatory Requirements for the Utility Industry



– adapted from Wegman (EPA 2003) Updated 2.15.10

2.2 Grid Modernization

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

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

2.3 Plug-in Hybrid Electric Vehicles

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

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

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

2.4 Renewable Energy Standards

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

2.4.1 South Dakota Renewable Energy Standard[6]

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

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

Annual reporting to the SDPUC is required.

2.4.2 Montana[7]

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

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

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

[7] DSIRE: Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MT11R&state=MT&CurrentPageID=1&RE=1&EE=1

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

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

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

3.0 Assumptions

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

3.1 Coal Price Forecasts

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

Table 3-1
Coal Price Forecast

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

3.2 Natural Gas Price Forecasts

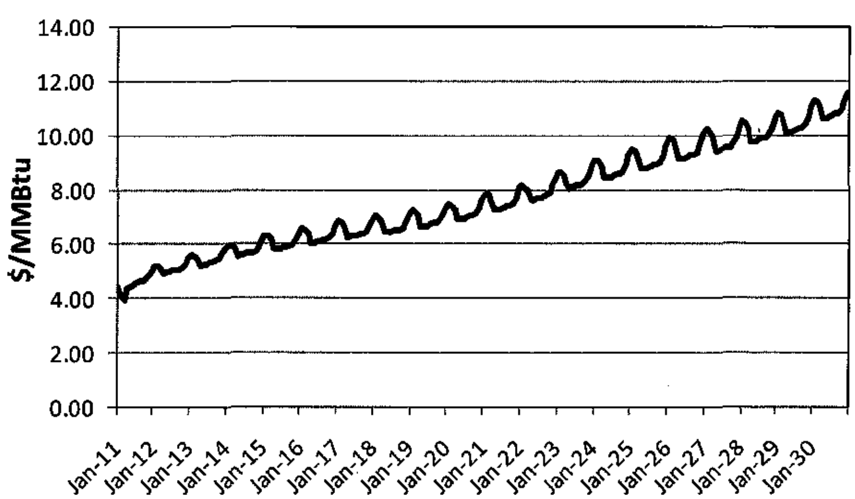
BHP used the natural gas price forecasts from Ventyx's WECC 2011 Spring Reference Case. The Henry Hub values were adjusted by the cost of transportation to reflect the price of natural gas as actually delivered to BHP generating facilities. The Henry Hub natural gas prices are shown monthly in Table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

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

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

Source: Ventyx

Figure 3-1
Henry Hub Natural Gas Prices

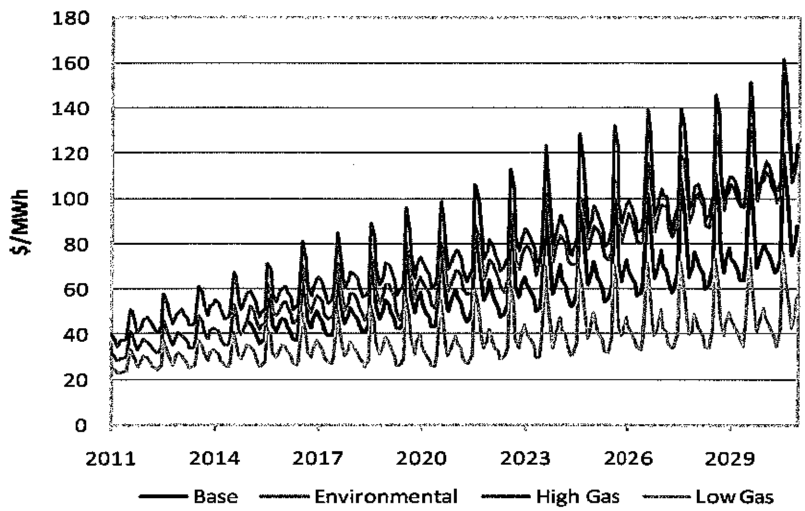


Source: Ventyx

3.3 Market Price Forecasts

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

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



3.4 Financial Parameters

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

Table 3-3
Financial Parameters

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

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

3.5 Planning Reserves

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

3.6 Emissions Costs

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

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

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

Source: Ventyx

4.0 Load Forecast

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

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

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

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

Figure 4-1

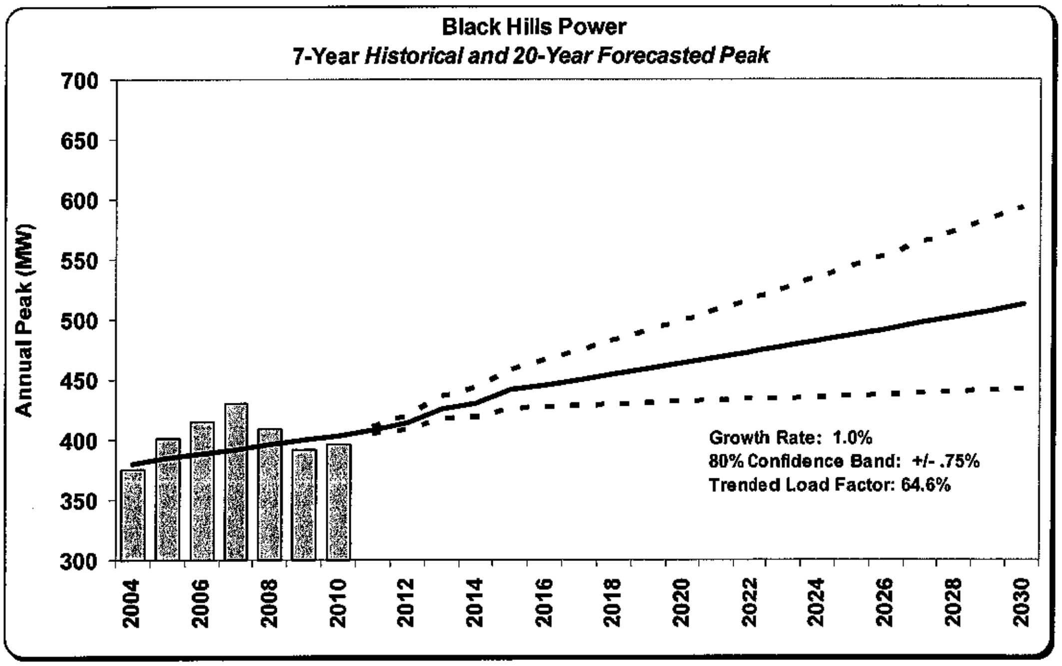


Figure 4-2

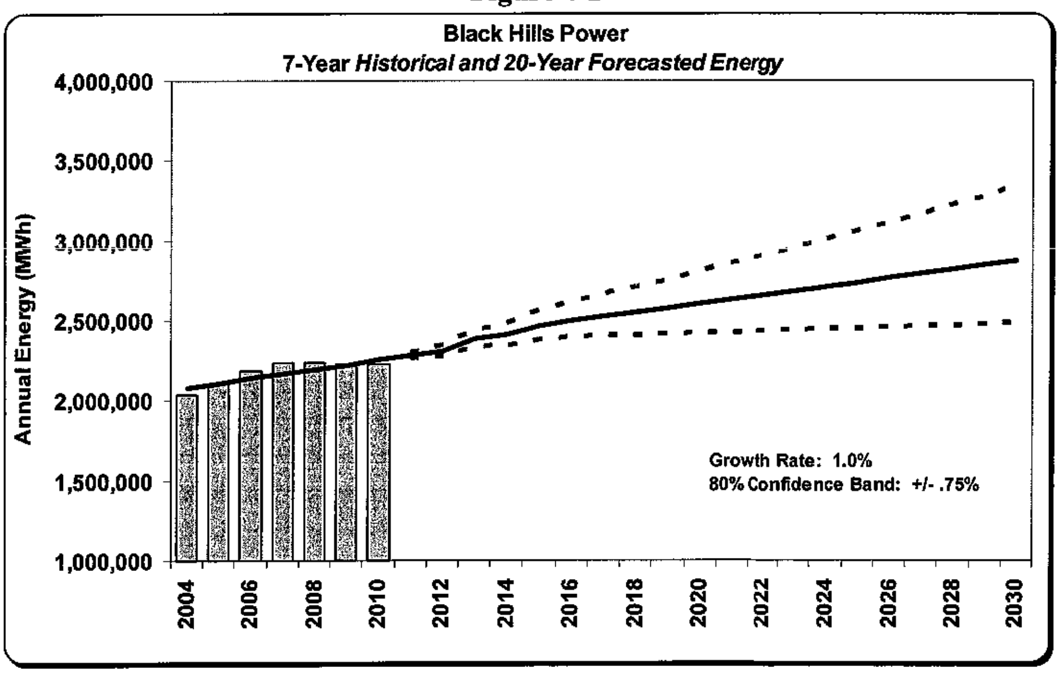


Table 4-2 provides a side-by-side comparison of the values projected for peak demand and annual energy in the 2005 IRP, the 2007 IRP, and in the forecast prepared for this 2011 IRP. The forecast from the 2007 IRP reflects a very strong economy and thus a higher load growth than is seen for the 2011 IRP.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

Table 4-2
Load Forecast Comparison

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

5.0 Demand-Side Management

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

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

5.1 Residential Water Heating

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

5.2 Residential Refrigerator Recycling

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

5.3 Residential Heat Pumps

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

5.4 School-Based Energy Education

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

5.5 Residential Audits

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

5.6 Weatherization Team

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

5.7 Commercial and Industrial Prescriptive and Custom Rebates

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

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

Table 5-1
DSM Program Portfolio – Year 1

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

Table 5-2
DSM Program Portfolio – Year 2

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

Table 5-3
Electric Program Portfolio – Year 3

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

Table 5-4
Program Budgets

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

6.0 Supply-Side Resources

6.1 Existing Resources

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

Table 6-1
BHP Existing Resources

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

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

6.2 Existing Unit Retirements and Upgrades

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

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

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

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

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

Table 6-2
Existing Unit Upgrades Performance Parameters

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

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

6.3 New Conventional Resources

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

6.3.1 Coal

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

Table 6-3
Coal-Fired Power Plant Performance Parameters

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

6.3.2 Combined Cycle Combustion Turbines

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

6.3.3 Simple Cycle Combustion Turbine

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

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

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

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

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

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

6.3.4 Existing Unit Purchase

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

Table 6-6
Existing Unit Purchase Performance Parameters

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

6.4 New Renewable Resources

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

6.4.1 Photovoltaic

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

Table 6-7
PV Performance Parameters

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

6.4.2 Wind

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

Table 6-8
Wind Performance Parameters

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

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

7.0 Resource Need Assessment

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

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

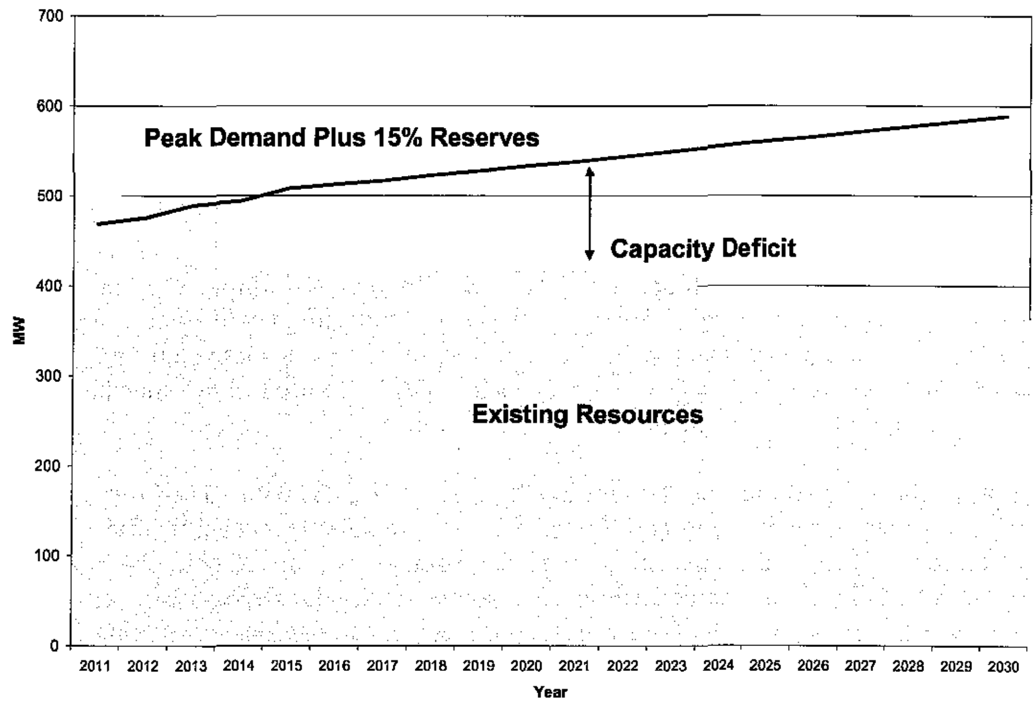
The Area Source Rules have an impact on BHP's Ben French, Neil Simpson 1, and Osage coal-fired generation units. Currently, the Osage units are in cold storage and not counted as an existing resource based on economics, but Ben French and Neil Simpson 1 are in operation and relied upon for system capacity.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

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

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

The totality of the requirements for new resources, incorporating the need for a minimum planning reserve margin of 15% and reflecting that BHP has no committed resources (resources that are planned and/or under construction but are not currently operational) in its generation portfolio as determined from the load and resource balance, is shown on Figure 7-1. The capacity deficit in any year is reflected as the distance between the line labeled "Peak Demand Plus 15% Reserves" and the top of the shaded block for "Existing Resources". The capacity deficit reaches approximately 225 MW by the end of the planning horizon.

Figure 7.1
Black Hills Power Load and Resource Summary



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

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

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

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

7.1 Analysis

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

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

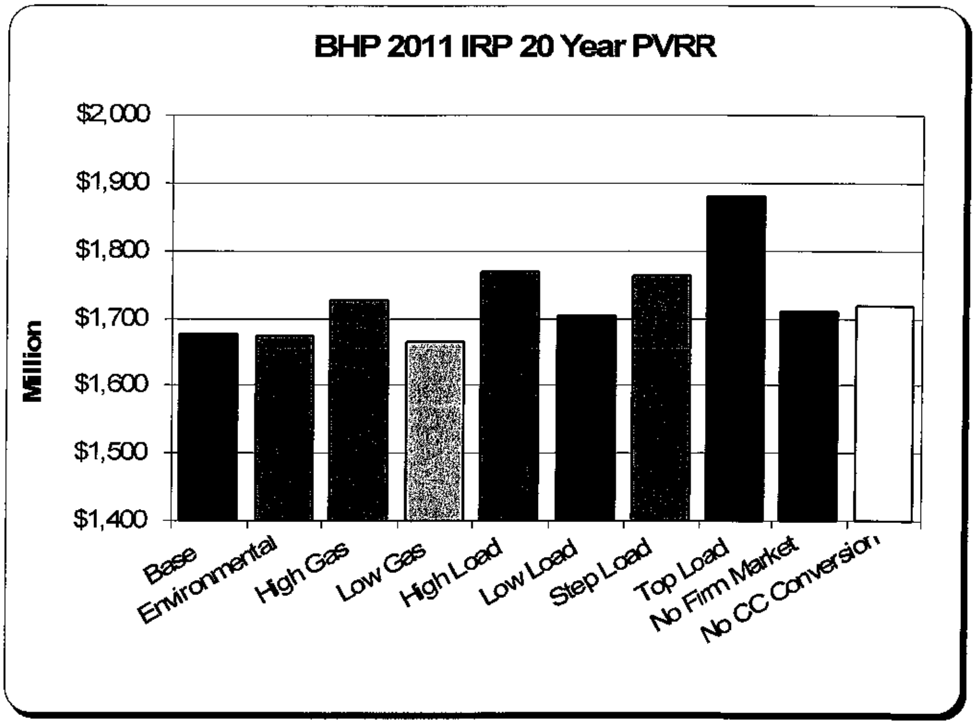
Capacity expansion modeling results (resource portfolios) for these scenarios are shown in Table 7-2.

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

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

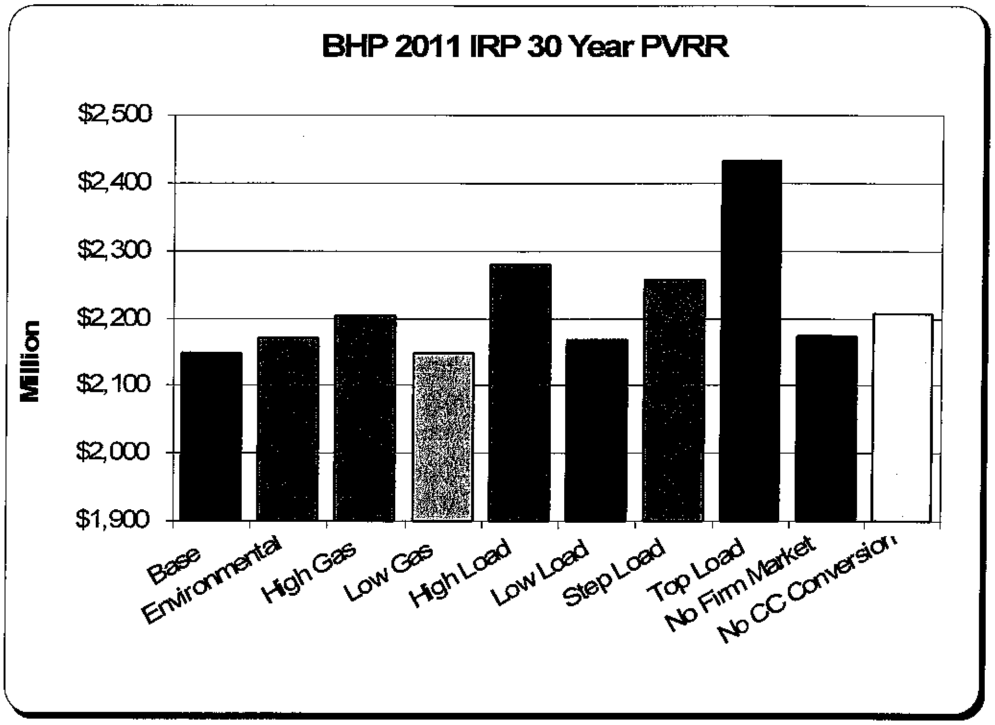
Each of the resource portfolios was then run through a production cost model, and was modeled with the base case scenario assumptions to determine the relative present value of revenue requirements (PVRR). The PVRR for all of the scenarios when run on a deterministic basis are shown on Figure 7-2.

Figure 7-2
Deterministic PVRR for Scenarios



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

Figure 7-3
Deterministic PVRR for Scenarios



8.0 Risk Analysis

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

8.1 Stochastic Analysis

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

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

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

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

Table 8-1
Ranges for Selected Uncertainty Variables

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

Source: Ventyx

8.2 Risk Profiles

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

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

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

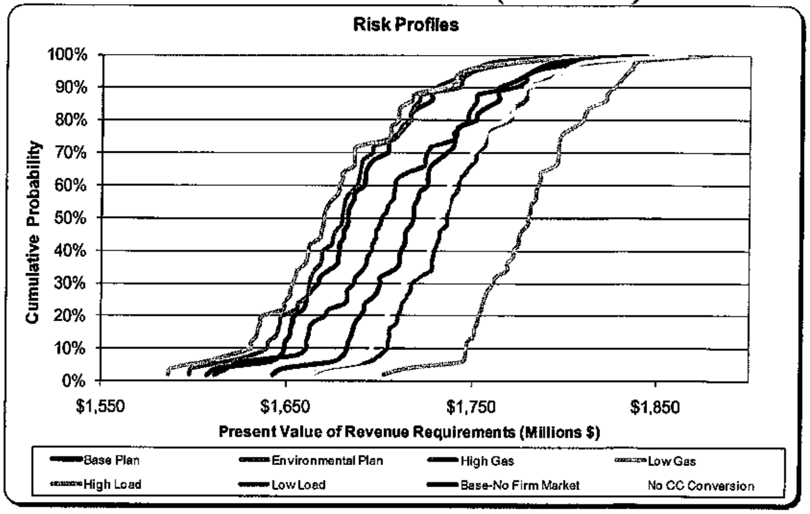
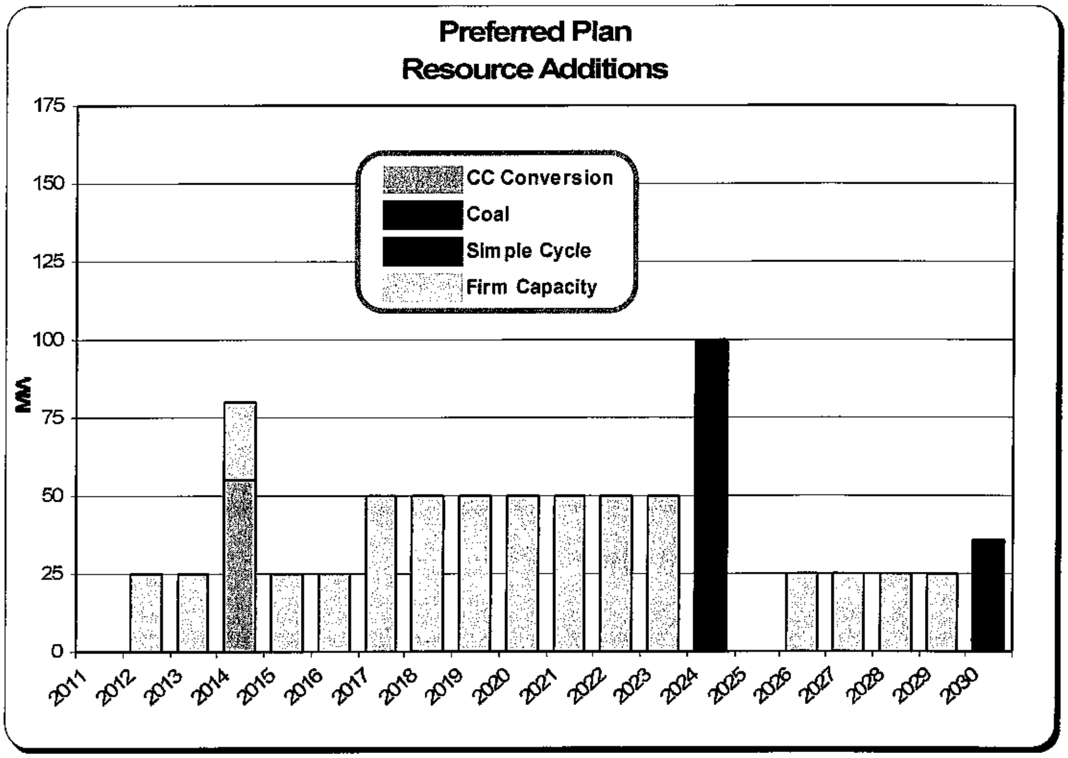


Figure 8-1 shows that with the exception of the low gas and the environmental scenarios, the risk profile for the base plan is to the left and lower than any other case. End effects as discussed in section 7.1 are impacting the risk profiles for the low gas and environmental scenario. The low gas scenario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

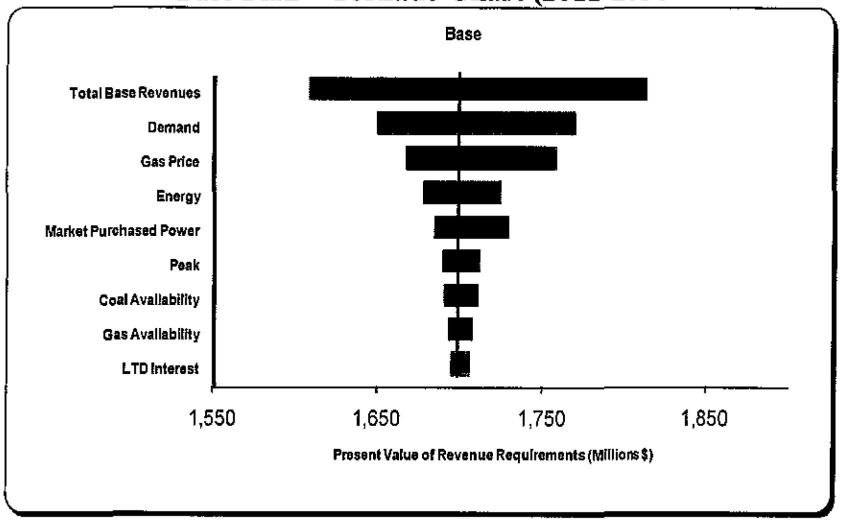
Figure 8-2
Preferred Plan – Resource Additions



8.3 Sensitivity Drivers

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

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



8.4 Comparison to 2005 and 2007 IRP

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

Table 8-2
Preferred Plan Resource Comparison

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

9.0 Conclusions and Recommendations

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

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

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

9.1 Action Plan

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

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

Appendix A – Software Used in the Analysis

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

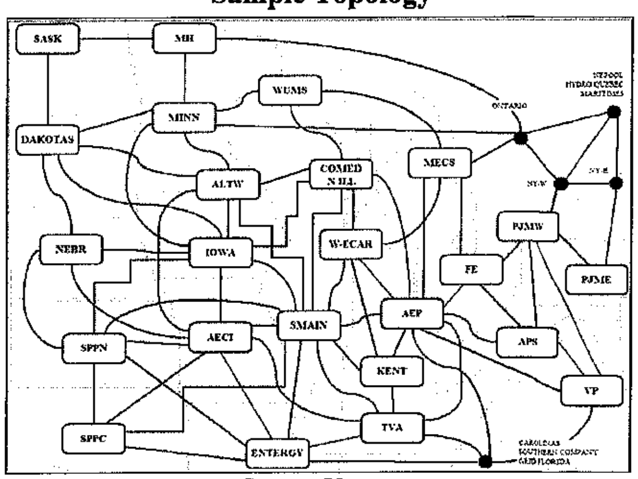
- Markets
- Portfolio
- Financial
- Risk

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

A.1 Markets Module

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

Figure A-1
Sample Topology



Source: Ventyx

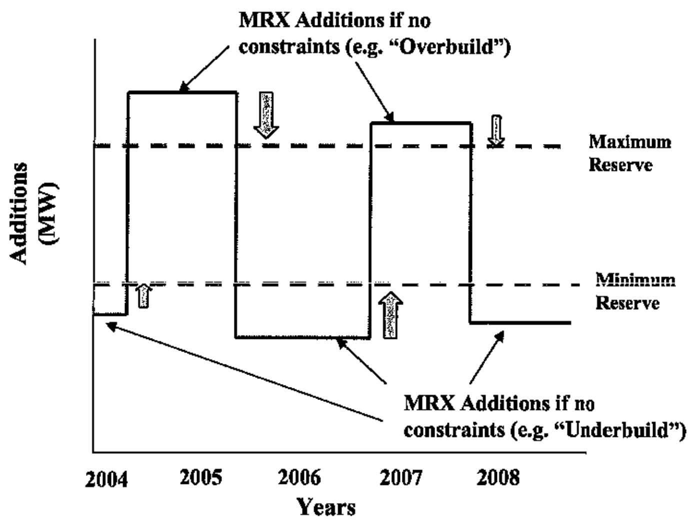
The database is populated with Ventyx Intelligence – Market Ops information. Operational information provided for over 10,000 generating units.

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

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

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

Figure A-2
MRX Decision Basis



Source: Ventyx

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

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

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

A.2 Portfolio Module

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

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

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

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

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

A.3 Capacity Expansion Module

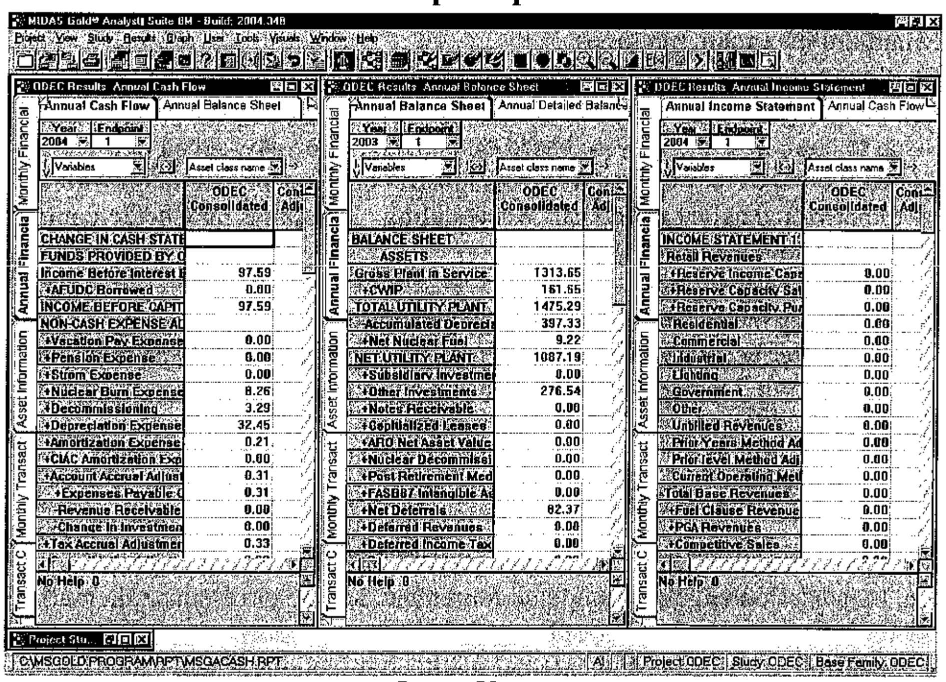
Capacity Expansion automates screening and evaluation of generation capacity expansion, transmission upgrades, strategic retirement, and other resource alternatives. It is a detailed and fast economic optimization model that simultaneously considers resource expansion investments and external market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

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

A.4 Financial Module

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

Figure A-3
Sample Reports



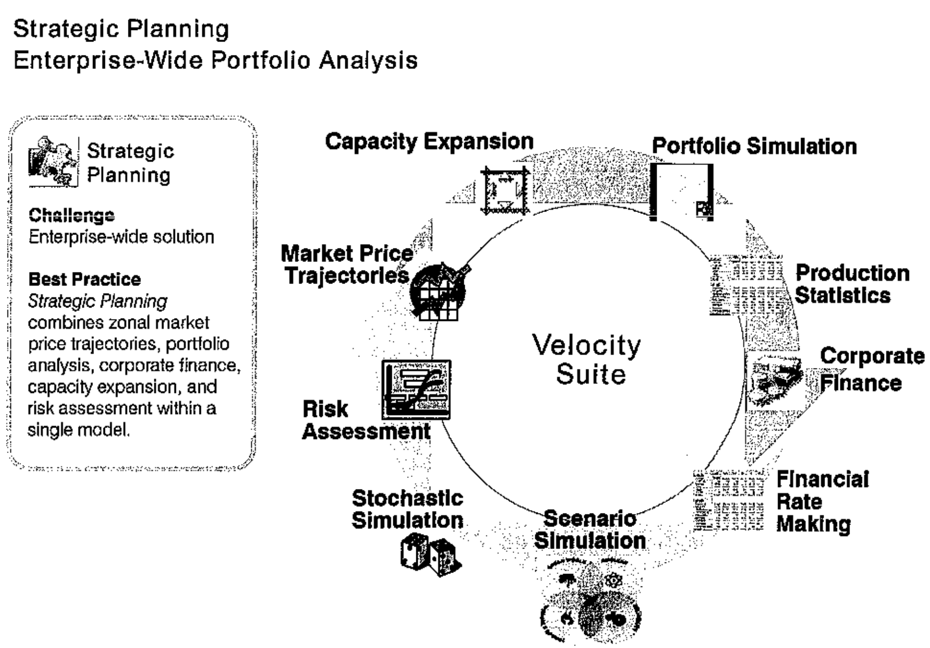
Source: Ventyx

A.5 Risk Module

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

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

Figure A-4
Overview of Process



Source: Ventyx

Appendix B

Table B-1

Black Hills Power
Load and Resource Balance - Preferred Plan

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Demand*	408	414	426	430	442	446	450	455	459	464	468	473	478	483	488	492	497	502	507	512
DSM	0	(1)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Peak Demand	408	413	424	427	439	443	447	452	456	461	465	470	475	480	485	489	494	499	504	509
15% Reserve margin	61	62	64	64	66	66	67	68	68	69	70	71	71	72	73	73	74	75	76	76
Total Demand	469	475	488	491	505	509	514	520	524	530	535	541	546	552	558	562	568	574	580	585
(including planning reserves)																				
Resources																				
Ben French 1	22	22	22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson I	16	16	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Neil Simpson II	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Wyodak	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Ben French Diesels	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Ben French CTs 1-4	100	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Lange CT	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Neil Simpson CT1	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Wygen III**	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Combined Cycle Conversion				55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
New Coal														100	100	100	100	100	100	100
New Combustion Turbine																				36
Total BHP Resources	468	440	440	457	457	457	457	457	457	457	457	457	457	557	557	557	557	557	557	593
Purchases																				
Colstrip	50	50	50	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0
Happy Jack	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0	0
Silver Sage	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0
Capacity	0	25	25	25	25	25	50	50	50	50	50	50	50	0	0	25	25	25	25	0
Sales																				
Sales (MEAN)	30	30	30	30	20	20	20	15	15	12	12	10	10	0	0	0	0	0	0	0
Total Resources	491.5	488.5	488.5	505.5	515.5	515.5	540.5	545.5	545.5	548.5	548.5	550.5	550.5	560.5	560.5	585.5	585.5	585.5	584.0	593.0
Reserve Margin***	5.5%	3.3%	0.2%	3.4%	2.4%	1.4%	5.9%	5.7%	4.6%	4.0%	3.0%	2.1%	0.9%	1.6%	0.6%	4.7%	3.5%	2.3%	0.9%	1.5%

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

Appendix C – Carbon Capture and Sequestration Technologies

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

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

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

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

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

Appendix D – Grid Modernization

Grid modernization is expected to facilitate:[8]

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

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

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

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

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

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

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

Abbreviations

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

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