Direct Testimony and Exhibits
Eric Scherr

Before the Public Service Commission
of the State of Wyoming

Joint Application of
Cheyenne Light, Fuel and Power Company
and Black Hills Power, Inc.
For a Certificate of Public Convenience
and Necessity for a Gas-Fired
Electric Generating Power Plant and
Related Facilities

Docket No. 20003-___-EA-11

Record No._____

Docket No. 20002-____-EA-11

November 1, 2011

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I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Eric Scherr. My business address is 2828 Plant Street, Suite B, Rapid City, SD 57709

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am a Resource Planning Engineer for Black Hills Utility Holding Company, Inc. an affiliate of Cheyenne Light, Fuel and Power Company ("Cheyenne Light" or "Company") and Black Hills Power, Inc. (Black Hills Power).

Q. FOR WHOM ARE YOU TESTIFYING ON BEHALF OF TODAY?

A. I am testifying on behalf of Cheyenne Light and Black Hills Power.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND WORK BACKGROUND.

A. I graduated from the South Dakota School of Mines and Technology with a B.S. degree in Mechanical Engineering in 2003. I worked for Quad Graphics, a commercial printing company, from 2003 – 2008 as a plant engineer where I focused on construction and energy management. I earned my MBA with an emphasis in finance and energy management from the University of Oklahoma in 2008. In 2008, I joined Black Hills Corporation as a resource planning engineer.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN PROCEEDINGS BEFORE THE WYOMING PUBLIC SERVICE COMMISSION (THE "COMMISSION")?

A. No, I have not.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide the Commission with an overview of the integrated resource planning analyses undertaken by Cheyenne Light and Black Hills Power. The IRP analysis for Cheyenne Light led to the conclusion that three combustion turbine generators ("CTG") with a net output of 38 MW each should be built or otherwise acquired by June 2014 to meet the electric needs of Cheyenne Light's customers to provide reliable and economic service. Black Hills Power's IRP analysis led to the conclusion that Black Hills Power should convert an existing simple cycle gas-fired turbine to a combined cycle unit in 2014. I also provide an overview of the analysis that was undertaken that resulted in the decision to build one CTG for Cheyenne Light and one jointly-owned combined cycle unit (CC) (jointly-owned by Cheyenne Light and Black Hills Power) in 2014.

III. IRP OVERVIEW

Q. WHAT ANALYSES WERE UNDERTAKEN TO DETERMINE HOW CHEYENNE LIGHT AND BLACK HILLS POWER SHOULD BEST MEET THEIR OBLIGATIONS TO PROVIDE CUSTOMERS WITH ELECTRIC SERVICE?

A. Each company independently undertook an Integrated Resource Planning (IRP) process to examine the full range of appropriate supply-side alternatives available to select as the resources to provide its customers with reliable and economic power in the future. This analysis considered a range of conventional supply-side resources as well as renewable resources. The IRP included risk analysis for a broad variety of factors to gauge each company's risk exposure based on the model-selected resources. A copy of the Cheyenne Light IRP is provided as Exhibit ES-1 to my testimony. A copy of the Black Hills Power IRP is provided as Exhibit ES-2 to my testimony.

Q. WHAT CONCLUSION DID CHEYENNE LIGHT REACH DURING THE IRP PROCESS AS TO WHAT RESOURCE SHOULD BE SELECTED FOR CHEYENNE LIGHT'S CUSTOMERS?

A. After thorough review of the electric load and generation resource balance and modeling results, Cheyenne Light concluded that for the years 2011-2013, Cheyenne Light should continue to purchase firm capacity for peak load hours during the summer months to provide for the summer capacity shortfall and that Cheyenne Light should build or otherwise procure three small combustion turbines for operation in 2014. However, after the subsequent completion of Black Hills Power's IRP, which indicated a resource need in the 2014 time frame that included the conversion of an existing CTG to a combined-cycle combustion turbine (CC), Cheyenne Light was presented with the opportunity to jointly-own a CC resource. As a result, Cheyenne Light reconsidered its decision to build three CTGs and is requesting approval for the installation of one CTG and joint ownership in a CC resource. The reasons for this decision are discussed further in Section XVI of my testimony and in the testimony of Kyle White.

Q. WHAT CONCLUSION DID BLACK HILLS POWER REACH DURING THE IRP PROCESS AS TO WHAT RESOURCE SHOULD BE SELECTED FOR BLACK HILLS POWER'S CUSTOMERS?

A. After thorough review of the electric load and generation resource balance and modeling results, Black Hills Power concluded that during the summer months, Black Hills Power should continue to purchase a firm 6 x 16 product (six days per week, 16 hours per day) to provide for the summer capacity shortfall. In 2014, Black Hills Power should convert an existing simple cycle gas turbine to a combined cycle unit for an incremental net increase of 55 MW.

Q. WHAT WAS YOUR ROLE IN THE IRP PROCESS?

A. I provided oversight and input for the IRP process, reviewed and approved all results and assisted in writing the IRP report. I hired two consultants, Technically Speaking, Inc. and Ventyx Advisors ("Ventyx") that provided load forecasting, modeling, analysis and report writing services to Cheyenne Light and Black Hills Power for completion of the IRPs.

Q. WHAT WERE THE CONSULTANTS' ROLES IN THE IRP PROCESS?

A. Ms. Diane Crockett of Ventyx completed the load forecast, capacity expansion simulations and production cost modeling in the preparation of each IRP. In addition, natural gas and electric market price forecasts developed by Ventyx were used in each IRP. To complete the capacity expansion and production cost modeling, Ventyx used its *Strategic Planning* software.

Ms. Tietjen provided input during the IRP planning process, analyzed all the modeling results, validated the conclusions that were drawn from the results and assisted in preparation of the IRP reports.

IV. ASSUMPTIONS FOR THE CHEYENNE LIGHT IRP

Q. WHAT CATEGORIES OF ASSUMPTIONS UNDERLIE THE PREPARATION OF AN IRP?

A. A load forecast of projected peak demands and annual energy consumption is required. In addition, assumptions are needed for fuel prices, financial parameters, capital cost of generation resources, the level of reserves required, plant operational parameters, and the market price of energy.

Q. PLEASE DESCRIBE THE PRICE FORECASTS USED FOR FUEL.

A. Cheyenne Light used a coal price forecast that reflects the cost as of May 2010 incurred for fuel from the Wygen II coal-fired generating unit. The coal forecast was then escalated to match Ventyx's 2010 Fall Reference Case annual coal escalation averaging 3% per year. Natural gas price forecasts were developed from Ventyx's WECC 2010 Fall Reference Case Henry Hub forecast. The Henry Hub values were adjusted for transportation costs to more accurately reflect the price of natural gas as actually delivered to Cheyenne, Wyoming.

Q. PLEASE DESCRIBE THE ASSUMPTIONS USED FOR THE MARKET PRICE OF ENERGY.

A. Electricity price estimates for the Wyoming region were derived from Ventyx's 2010 Fall Reference Case and are the basis on which Cheyenne Light's market transactions were priced. Values were developed for four differing scenarios that require correlation between natural gas prices and market prices – base, environmental, low gas, and high gas. The different scenarios included in the Cheyenne Light IRP are discussed more fully in Section 7.1 of Exhibit ES-1.

Q. PLEASE DESCRIBE THE FINANCIAL PARAMETER ASSUMPTIONS USED FOR THIS IRP.

A. Assumptions were required for financial parameters including the discount rate, the capital structure, and the levelized fixed charge rates for each of the resource alternatives.

Q. PLEASE DESCRIBE THE CAPITAL COST ASSUMPTIONS OF GENERATION RESOURCES.

A. Cheyenne Light used the Ventyx 2010 Fall Power Reference Case for capital cost assumptions associated with a variety of natural gas-fired configurations and renewable generation. Cheyenne Light provided capital cost assumptions for small pulverized coal generating units, and small CC and simple cycle (SC) gas-fired configurations as described in Mark Lux's testimony.

Q. WHAT LEVEL OF PLANNING RESERVE MARGIN WAS USED?

A. Cheyenne Light assumed a planning reserve margin of 15% over projected peak demand for this analysis.

Q. WHAT EMISSION COST ASSUMPTIONS WERE USED FOR THE IRP?

A. The Ventyx 2010 Fall Power Reference Case does not include any carbon taxes in their base case assumptions over the planning horizon. Carbon assumptions from

Ventyx's environmental scenario were used in the IRP environmental scenario. For this scenario, costs for carbon emissions were assumed to begin in 2015. The different scenarios included in the Cheyenne Light IRP are discussed more fully in Section 7.1 of Exhibit ES-1.

V. LOAD FORECAST UNDERLYING THE CHEYENNE LIGHT IRP

Q. PLEASE DESCRIBE THE PROCESS USED TO DETERMINE THE LOAD FORECAST AND THE RESULTS.

A. Ventyx developed a load forecast for Cheyenne Light by trending historical peak demands and annual energy and modifying the results to reflect expected load gains. The trended growth rate for Cheyenne Light is 1.5% for both peak demand and annual energy.

Q. HOW DOES THE LOAD FORECAST DETERMINE CAPACITY REQUIREMENTS FOR CHEYENNE LIGHT?

A. Cheyenne Light must maintain sufficient capacity to support peak load requirements plus planning reserves. Cheyenne Light has a legal obligation to serve the needs of its customers – as those needs exist today and as they grow over time. The need for resources is shown in Exhibit ES-1 in Appendix B on Table B-1. Cheyenne Light is already operating with a capacity deficit.

VI. ENERGY EFFICIENCY FOR THE CHEYENNE LIGHT IRP

Q. PLEASE DESCRIBE HOW THE ENERGY EFFICIENCY (EE) PLAN WAS INCORPORATED INTO THE IRP ANALYSIS.

A. The EE plan that is outlined in a report for Cheyenne Light dated April 30, 2010 and was part of Cheyenne Light's Docket 20003-108-EA-10 was used for the IRP modeling.

Q. WHAT PROGRAMS ARE REFLECTED IN THE APRIL 30, 2010 REPORT?

A. Cheyenne Light's EE plan portfolio includes water heating, refrigerator pick-up, lighting and energy audits for its residential customers and prescriptive rebates and custom rebates for its commercial and industrial customers.

Q. IS THIS THE SAME PLAN THAT WAS APPROVED BY THE COMMISSION?

A. The plan modeled in the IRP is slightly different than the plan approved by the Commission. IRP modeling was completed prior to Commission approval of Cheyenne Light's EE plan and the approved EE plan includes slight modifications to the residential water heater and residential lighting programs as requested by the Commission.

Q. ARE THERE SIGNIFICANT DIFFERENCES BETWEEN THE PEAK DEMAND SAVINGS OF THE APPROVED PLAN AND THE EE PLAN MODELED IN THE IRP?

A. No, there are not. The peak demand savings of both the original filed plan and the approved plan round to 3 MW in year 3 of the plan.

Q. WHAT HAPPENS TO THE EE PLAN IN THE IRP AFTER YEAR 3?

A. An EE plan is assumed to remain in effect and achieve a savings of 3 MW in each year after year 3 of the program. Additionally, we have run a low load scenario which would simulate load reductions from future EE plans.

Q. WHAT WOULD BE THE EFFECT OF HIGHER LEVELS OF EE IN 2014-2030 IN THE IRP?

A. It is possible that one or more resources in the later years of the IRP could potentially be delayed. However, in the near term – for at least the next five years – additional EE plans would not delay the need for a resource in 2014.

Q. HAS CHEYENNE LIGHT ENGAGED IN ACTIVITIES TO REDUCE FUTURE DEMAND OUTSIDE OF THE APPROVED EE PLAN?

A. As discussed in the testimony of Mark Stege, Cheyenne Light has initiated discussions with its two largest customers to explore peak shaving opportunities.

Q. IF POSSIBLE, WOULD THAT CHANGE THE RESULT OF THE IRP OR THE NEED FOR RESOURCES IN 2014?

A. No. It would not change the results of the IRP or the need for resources in 2014. These large customers have a high load factor and, while shifting some load would have an effect on the peak, it would not be significant enough to delay this resource need.

VII. SUPPLY-SIDE RESOURCES FOR THE CHEYENNE LIGHT IRP

Q. PLEASE DESCRIBE THE EXISTING CHEYENNE LIGHT RESOURCES.

A. Cheyenne Light owns the Wygen II coal-fired generating unit located in Gillette, Wyoming. In addition, Cheyenne Light obtains power under power purchase agreements (PPA) from Wygen I, a coal-fired plant, "CT2" a combustion turbine, and wind-generated power from Happy Jack Windpower, LLC and Silver Sage Windpower, LLC. Details regarding each of these resources are shown on Table 6-1 of Exhibit ES-1.

Q. PLEASE DESCRIBE THE RANGE OF NEW CONVENTIONAL RESOURCES EXAMINED IN THE COURSE OF PREPARING THE IRP.

A. Conventional resources examined in this IRP include coal-fired generation, simple cycle and wholly-owned combined cycle combustion turbines, and short-term power purchases.

Q. WHAT WERE THE RENEWABLE RESOURCES CONSIDERED IN THE COURSE OF PREPARING THE IRP?

A. The renewable resources considered were wind and solar photovoltaics.

VIII. RESULTS FOR THE CHEYENNE LIGHT IRP

Q. WHAT SCENARIOS WERE EXAMINED FOR THIS IRP ANALYSIS FOR THE CHEYENNE LIGHT SYSTEM?

A. Capacity expansion plans were developed for scenarios which are set forth in Section 7.1 of Exhibit ES-1.

Q. PLEASE DESCRIBE THE CAPACITY EXPANSION AND PRODUCTION COST MODELING ANALYSIS.

A. The different scenarios described in Section 7.1 of Exhibit ES-1 were run through the Capacity Expansion module of Ventyx's *Strategic Planning* software to determine the economic resource portfolio required to serve the load subject to the assumptions of that scenario. Each of the resource portfolios was then run through a production cost model, using the base case scenario assumptions to determine the comparable present value of revenue requirements (PVRR).

Q. WHAT WERE THE RESULTS OF THE CAPACITY EXPANSION AND PRODUCTION COST MODELING?

The results of the capacity expansion modeling varied between scenarios and are shown in Table 7-1 of Exhibit ES-1. The results of the production cost modeling are shown on Figure 7-2 of Exhibit ES-1. With the exception of the step load and low load scenarios, the PVRRs for the scenarios are within approximately 2% of each other.

IX. RISK ANALYSIS FOR THE CHEYENNE LIGHT IRP

Q. PLEASE DESCRIBE THE RISK ANALYSIS UNDERTAKEN IN COMPLETING THE IRP.

A. Stochastic analysis and stress tests were conducted as part of this IRP.

Q. PLEASE DESCRIBE THE STOCHASTIC ANALYSIS.

A. The stochastic analysis conducted by Ventyx examined a wide range of uncertainties that resulted in 50 future scenarios for price determination and evaluation of a given portfolio of resources. The specific uncertainties and the range of the values examined for each are provided on Table 8-1 of Exhibit ES-1. The uncertainties evaluated included the peak demand and energy forecast, natural gas price, oil price, unit availability and capital costs. This type of analysis reflects standard industry practice for IRP and resource selection.

Q. PLEASE DESCRIBE THE RESULTS OF THE STOCHASTIC ANALYSIS.

A. 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 the results of the stochastic analysis conducted by Ventyx for Cheyenne Light. Figure 8-1 of Exhibit ES-1 shows that with the exception of the low load case, the risk profile for the preferred plan is to the left and lower than any other case except that labeled the "base plan."

Q. PLEASE DESCRIBE THE STRESS TEST ANALYSIS.

A. Three stress tests were conducted to further evaluate Cheyenne Light's risk exposure due to future uncertainty and are described in Section 8.3 of Exhibit ES-1. These three stress tests involved the consideration of a step load in 2014, the examination of results if no firm energy market were available, and an environmental stress test. The information derived from these stress tests supported the selection of the preferred plan.

X. ASSUMPTIONS FOR THE BLACK HILLS POWER IRP

Q. WHAT CATEGORIES OF ASSUMPTIONS UNDERLIE THE PREPARATION OF AN IRP?

A. A load forecast of projected peak demands and annual energy consumption is required. In addition, assumptions are needed for fuel prices, financial parameters, capital cost of generation resources, the level of reserves required, plant operational parameters, and the market price of energy.

Q. PLEASE DESCRIBE THE PRICE FORECASTS USED FOR FUEL IN THE IRP.

A. Black Hills Power used a coal price forecast that reflects the cost at the time of the IRP modeling (May 2011) incurred for fuel from Black Hills Power's coal-fired generating units. The coal forecast was then escalated to match the Ventyx reference case annual coal escalation averaging 4% per year. Natural gas price forecasts were developed from Ventyx's WECC 2011 Spring Reference Case Henry Hub forecast. The Henry Hub values were adjusted for transportation costs to more accurately reflect the price of natural gas as actually delivered to Black Hills Power generating facilities.

Q. PLEASE DESCRIBE THE ASSUMPTIONS USED FOR THE MARKET PRICE OF ENERGY.

A. Electricity price estimates for the Wyoming region were derived from Ventyx's 2011 Spring Reference Case and are the basis on which Black Hills Power's market transactions were priced. Values were developed for four differing scenarios that require correlation between natural gas prices and market prices – base, environmental, low gas, and high gas. The different scenarios included in the IRP are discussed more fully in Section 7.1 of Exhibit ES-2.

Q. PLEASE DESCRIBE THE FINANCIAL PARAMETER ASSUMPTIONS USED FOR THIS IRP.

A. Assumptions were required for financial parameters including the discount rate, the capital structure, and the levelized fixed charge rates for each of the resource alternatives.

Q. PLEASE DESCRIBE THE CAPITAL COST ASSUMPTIONS OF GENERATION RESOURCES.

A. Black Hills Power used the Ventyx 2011 Spring Power Reference Case for capital cost assumptions associated with a variety of natural gas-fired configurations and renewable generation. Black Hills Power provided capital cost assumptions for small pulverized coal generating units, and small CC and simple cycle (SC) gas-fired configurations as described in Mark Lux's testimony.

Q. WHAT LEVEL OF PLANNING RESERVE MARGIN WAS USED?

A. Black Hills Power assumed a planning reserve margin of 15% over projected peak demand for this analysis.

Q. WHAT EMISSION COST ASSUMPTIONS WERE USED FOR THE IRP?

A. The Ventyx 2011 Spring Power Reference Case does not include any carbon taxes in their base case assumptions over the planning horizon. Carbon tax assumptions from Ventyx's environmental scenario were used in the IRP environmental scenario. For this scenario, costs for carbon emissions were assumed to begin in 2015. The different scenarios included in the IRP are discussed more fully in Section 7.1 of Exhibit ES-2.

XI. LOAD FORECAST UNDERLYING THE BLACK HILLS POWER IRP

Q. PLEASE DESCRIBE THE PROCESS USED TO DETERMINE THE LOAD FORECAST AND THE RESULTS.

A. Ventyx developed a load forecast for Black Hills Power by trending historical peak demands and annual energy and modifying the results to reflect expected load gains. The trended growth rate for Black Hills Power is 1.0% for both peak demand and annual energy.

Q. HOW DOES THE LOAD FORECAST DETERMINE CAPACITY REQUIREMENTS FOR BLACK HILLS POWER?

A. Black Hills Power must maintain sufficient capacity to support peak load requirements plus planning reserves. Black Hills Power has a legal obligation to serve the needs of its customers – as those needs exist today and as they grow over time. The need for resources is shown in Exhibit ES-2 in Appendix B on Table B-1. Black Hills Power is already operating with a capacity deficit.

XII. DEMAND-SIDE MANAGEMENT FOR THE BLACK HILLS POWER IRP

Q. PLEASE DESCRIBE HOW THE ENERGY EFFICIENCY (EE) PLAN WAS INCORPORATED INTO THE IRP ANALYSIS.

A. The demand-side management (DSM) programs as defined in Docket #EL11-002 and approved by the South Dakota Public Utilities Commission on June 28, 2011 were used for the IRP modeling.

Q. WHAT PROGRAMS ARE REFLECTED IN THAT DOCKET?

A. Black Hills Power's DSM program portfolio includes water heating, refrigerator recycling, heat pumps, school-based efficiency, energy audits, and weatherization teams for its residential customers and prescriptive rebates and custom rebates for its commercial and industrial customers.

Q. WHAT HAPPENS TO THE DSM PLAN IN THE IRP AFTER YEAR 3?

A. A DSM plan is assumed to remain in effect and achieve the same level of savings of approximately 1.5 MW in each year after year 3 of the program. Additionally, we have run a low load scenario which would simulate load reductions from future DSM programs.

Q. WHAT WOULD BE THE EFFECT OF HIGHER LEVELS OF DSM IN 2014 - 2030 IN THE IRP?

A. It is possible that one or more resources in the later years of the IRP could potentially be delayed. However, in the near term – for at least the next five years – additional DSM programs would not delay the need for a resource in 2014.

XIII. SUPPLY-SIDE RESOURCES FOR THE BLACK HILLS POWER IRP

Q. PLEASE DESCRIBE THE EXISTING BLACK HILLS POWER RESOURCES.

A. Black Hills Power owns coal-fired units, natural gas-fired units, diesel-fired units, and purchases energy under long-term PPAs. Resources committed under current PPAs included 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. Details about each of these resources are shown on Table 6-1 of Exhibit ES-2.

Q. PLEASE DESCRIBE THE RANGE OF CONVENTIONAL RESOURCES EXAMINED IN THE COURSE OF PREPARING THE IRP.

A. Conventional resources examined in this IRP include existing unit upgrades and existing unit purchases as well as new resources in the form of coal-fired capacity, simple cycle and combined cycle combustion turbines, and short-term power purchases.

Q. WHAT WERE THE RENEWABLE RESOURCES CONSIDERED IN THE COURSE OF PREPARING THE IRP?

A. The renewable resources considered were wind and solar photovoltaics.

XIV. RESULTS FOR THE BLACK HILLS POWER IRP

Q. WHAT SCENARIOS WERE EXAMINED FOR THIS IRP ANALYSIS FOR THE BLACK HILLS POWER SYSTEM?

A. Capacity expansion plans were developed for scenarios which are set forth in Section 7.1 of Exhibit ES-2.

Q. PLEASE DESCRIBE THE CAPACITY EXPANSION AND PRODUCTION COST MODELING ANALYSIS.

A. The different scenarios described in Section 7.1 of Exhibit ES-2, were run through the Capacity Expansion module of Ventyx's *Strategic Planning* software to determine the economic resource portfolio required to serve the load subject to the assumptions of that scenario. Each of the resource portfolios was then run through a production cost model, using the base case scenario assumptions to determine the comparable present value of revenue requirements (PVRR).

Q. WHAT WERE THE RESULTS OF THE CAPACITY EXPANSION AND PRODUCTION COST MODELING?

The results of the capacity expansion modeling varied between scenarios and are shown in Table 7-2 of Exhibit ES-2. The results of the production cost modeling are shown on Figure 7-2 of Exhibit ES-2.

XV. RISK ANALYSIS FOR THE BLACK HILLS POWER IRP

Q. PLEASE DESCRIBE THE RISK ANALYSIS UNDERTAKEN IN COMPLETING THE IRP.

A. Stochastic analysis was conducted as part of this IRP.

Q. PLEASE DESCRIBE THE STOCHASTIC ANALYSIS.

A. The stochastic analysis conducted by Ventyx examined a wide range of uncertainties that resulted in 50 future scenarios for price determination and evaluation of a given portfolio of resources. The specific uncertainties and the range of the values examined for each are provided on Table 8-1 of Exhibit ES-2. The uncertainties evaluated included the peak demand and energy forecast, natural gas price, oil price, unit availability and capital costs. This type of analysis reflects standard industry practice for IRP and resource selection.

Q. PLEASE DESCRIBE THE RESULTS OF THE STOCHASTIC ANALYSIS.

A. 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 the results of the stochastic analysis conducted by Ventyx for Black Hills Power. Figure 8-1 of Exhibit ES-2 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. As explained in Section 8.2 of Exhibit ES-2, the end effects of generation additions in later years are influencing the risk profiles.

XVI THE RESOURCES REQUESTED IN THIS APPLICATION

Q. PLEASE DESCRIBE THE RESOURCES REQUESTED IN THIS APPLICATION AND HOW THEY RELATE TO THE RESOURCE SELECTIONS FROM THE CHEYENNE LIGHT AND BLACK HILLS POWER IRPs.

A. This application requests permission to build one CTG to be wholly-owned by Cheyenne Light and one CC unit to be jointly-owned by Cheyenne Light and Black Hills Power. The CC unit has two combustion turbines, two heat recovery steam generators, and one steam turbine. The preferred plan from the Cheyenne Light IRP demonstrated that the resource selection in 2014 should be three CTGs. The base plan from the Black Hills Power IRP demonstrated that the resource selection in 2014 should be the conversion of a CTG to combined cycle operation.

Q. PLEASE DISCUSS HOW THIS RESOURCE SELECTION WAS MADE.

A. As Cheyenne Light and Black Hills Power evaluated the results of the two IRPs, they recognized the synergies that would be possible from using two of the simple cycle combustion turbines indicated as the preferred resources in the Cheyenne Light IRP as the basis of the combined cycle conversion indicated in the Black Hills Power IRP. Additional analysis was conducted to verify this synergy.

That analysis resulted in the following decisions:

(1) The CC unit will be jointly owned by Cheyenne Light (42%) and Black Hills Power (58%). This meets the Black Hills Power resource need identified in its IRP.

(2) One combustion turbine wholly-owned by Cheyenne Light.

(3) Additional firm market purchases with associated capacity will be made in the years 2014 - 2016 for Cheyenne Light.

Q. WILL THE RESOURCES PROPOSED IN THIS APPLICATION FOR CHEYENNE LIGHT (ONE CTG AND JOINT OWNERSHIP IN A CC) RESULT IN LOWER PVRR THAN THE PREFFERED PLAN IN CHEYENNE LIGHT'S IRP?

A. Yes.

Q. PLEASE EXPLAIN.

A. While a CC unit has a higher capital cost than a CTG, Cheyenne Light is requesting approval for generation with a net output of 77 MW rather than the 114 MW identified in the preferred plan of the IRP. This, along with the reduced cost of energy associated with the more efficient operation of the CC, resulted in a lower PVRR.

Q. WHY IS CHEYENNE LIGHT ONLY BUILDING GENERATION WITH A NET OUTPUT OF 77 MW RATHER THAN 114 MW?

A. Many assumptions are made in any IRP. One assumption in Cheyenne Light's IRP was that firm market purchases were only available in July and August in 25

MW blocks up to a total of 50 MW. Once the opportunity arose for Cheyenne Light to participate in the CC, additional analysis was conducted that included a change to the firm market purchase assumption. The constraint on firm market purchases was changed to allow for capacity purchases in all months.

Because the IRP modeling assumed that firm market purchases were constrained in all months except summer months, resources were selected to cover all of Cheyenne Light's capacity needs reducing capacity market risk. Changing the constraint to allow for capacity purchases in all months allowed the model to select resources that provide less generating capacity such as the resources proposed in this Application.

This revised constraint in combination with the reduced cost of energy associated with the more efficient operation of the CC and lower total capital cost, resulted in a lower present value of revenue requirements (PVRR) than that of the IRP-identified preferred plan.

Q. HOW WAS THE OWNERSHIP PERCENTAGE OF THE CC BETWEEN CHEYENNE LIGHT AND BLACK HILLS POWER DETERMINED?

A. The ownership percentage of the CC was determined from the results of Black Hills Power's IRP. As discussed above, Black Hills Power's IRP preferred plan included conversion of an existing CTG to a CC for an incremental 55 MW addition to Black Hills Power's resources. Although Cheyenne Light's IRP indicated a need for 93 MW in 2014, analysis was completed after the option to jointly-own a resource with Black Hills Power was identified that indicated the addition of one CTG, 40 MW of the CC and firm market purchases will reliably and economically serve Cheyenne Light's customers.

Q. PLEASE DESCRIBE THE BENEFITS OF THE PROPOSED RESOURCES FOR CHEYENNE LIGHT AND BLACK HILLS POWER.

The benefits that result from the proposed resources (one CTG and one jointly-owned CC located in Cheyenne, Wyoming) include resource mix benefits, operational and environmental benefits, and market risk benefits.

Q. PLEASE DESCRIBE WHAT YOU MEAN BY RESOURCE MIX BENEFITS AND HOW THE RESOURCES IN THIS APPLICATION PROVIDE THOSE BENEFITS.

A. Generating units for the electric utility industry are generally categorized as baseload, intermediate, peaking, or super peaking. Baseload generating units generally operate seven days per week, 24 hours per day to meet the demand that is always present. Intermediate capacity "stacks" above baseload capacity and meets demand that occurs for 10-12 hours per day. Peaking capacity operates for brief periods of time to meet high demand hours. Super peaking operates for those very few hours when loads are at their highest levels.

A resource mix that consists of each of these types of capacity generally provides the most operating flexibility for utilities. At present, Cheyenne Light has baseload and peaking capacity. The addition of combined cycle capacity for both Black Hills Power and Cheyenne Light will enhance the resource mix of both utilities by providing intermediate capacity. Figure 3-4 in the Application includes Cheyenne Light's existing and proposed resources and shows how these resources would be utilized on Cheyenne Light's 2014 forecast peak day in the event economy energy is not available or not economic.

Q. PLEASE DESCRIBE WHAT YOU MEAN BY OPERATIONAL AND ENVIRONMENTAL BENEFITS AND HOW THE RESOURCES IN THIS APPLICATION PROVIDE THOSE BENEFITS.

A. Utilities operate their generating resources in the most economical manner subject to various operational/environmental constraints. For example, a wide range of ancillary services must be provided by generating units or purchased. These services ensure that the electric system remains stable when major outages of generating or transmission equipment occurs. The proposed jointly-owned CC operates more economically than combustion turbines thus providing more economic regulation, more economic operation, and lower carbon emissions.

Regulation: Assuming $6.00/MMBtu natural gas, for each hour that a CC provides regulation at 8,500 Btu/kWh as compared to that regulation coming from a combustion turbine at 12,000 Btu/kWh, savings of $21/MWh are realized.

Operation: Assuming $6.00/MMBtu natural gas and full load heat rates of 9,600 Btu/kWh (combustion turbine) and 7,947 Btu/kWh (combined cycle), each hour a CC operates versus a combustion turbine results in savings of $9.92/MWh.

Emissions: Assuming a carbon emission price of $15.00/ton and an emissions rate of 120 lb/MMBtu in association with the full load heat rates described above, a CC will generate fewer carbon emissions saving approximately $1.49/MWh versus a combustion turbine.

Q. PLEASE DESCRIBE WHAT YOU MEAN BY MARKET RISK BENEFITS AND HOW THE RESOURCES IN THIS APPLICATION PROVIDE THOSE BENEFITS.

A. A CC generates electricity with greater efficiency than a combustion turbine due to the capture of the waste heat from its combustion turbines. Combustion turbines are often installed for their capacity and with the expectation that they will rarely operate. A CC, however, is expected to operate many more hours and offsets the risk that energy will not be economically available in the market.

Q. WHAT IS YOUR CONCLUSION AFTER REVIEWING ALL OF THE ANALYSIS AND CONSIDERING THE COSTS AND BENEFITS?

A. I believe that the next resources that should be built to meet the peak demand and reserve margin requirements for Cheyenne Light and Black Hills Power are one CTG and one jointly-owned CC in Cheyenne, Wyoming.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.