Direct Testimony and Exhibits
Jill S. Tietjen

Before the South Dakota Public Utilities Commission
of the State of South Dakota

In the Matter of the Application of
Black Hills Power, Inc., a South Dakota Corporation

For Authority to Increase Rates
in South Dakota

Docket No. EL14-___

March 31, 2014

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EXHIBITS

I. INTRODUCTION & QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jill S. Tietjen. My business address is 8547 E. Arapahoe Road, PMB J189, Greenwood Village, Colorado.

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

A. I am the President and CEO of Technically Speaking, Inc., a firm that provides engineering consulting services. I have held this position since the firm was incorporated in August of 2005. Previously, I was self-employed as an engineering consultant.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND WORK BACKGROUND.

A. I graduated from the University of Virginia with a B.S. in Applied Mathematics (minor in Electrical Engineering) in 1976. I began my career with Duke Power Company and spent five years as a Planning Engineer in the System Planning Department (1976-1981). While at Duke Power Company, I earned my MBA from the University of North Carolina at Charlotte in 1979. I subsequently joined Mobil Oil Corporation's Mining and Coal Division where I worked from 1981-1984 as a planning analyst. I became a registered professional engineer in Colorado in 1982. I joined Stone & Webster Management Consultants in 1984 and by the time I left in 1992 had progressed to Assistant Vice President. I served as Principal and leader of the utility planning practice at Hagler Bailly Consulting during 1992-1995. In 1995, I rejoined Stone & Webster Management Consultants as an Assistant Vice President and office manager for the Denver office, a position that I served in through 1997. Since 1997, I have been on staff at the University of Colorado at Boulder. From 1997-2005, I was also self-employed as an engineering consultant. Also in 1997, I was elected as an outside director on the Board of Directors of Georgia Transmission Corporation and still serve in that capacity. In 2010, I was elected as an outside director for Merrick & Company of Aurora, Colorado. My resume, testimony listing, and publications listing are attached to my testimony as Exhibit JST-1.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes. I have testified before regulatory commissions in South Dakota, Wyoming, Colorado, Illinois, Kansas, Kentucky, Maine, Missouri, and Ohio. I have testified on behalf of Black Hills Corporation subsidiaries in South Dakota, Wyoming and Colorado.

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

A. I am testifying on behalf of Black Hills Power, Inc. (Black Hills Power).

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I demonstrate the need for a new resource on the Black Hills Power system in the 2014 timeframe. I discuss Black Hills Power's 2011 Integrated Resource Plan (BHP IRP) that was conducted to determine how that resource need should be fulfilled. I then discuss the selection of the Cheyenne Prairie Generating Station

(CPGS) as the resource that should be installed in 2014 and the associated rationale.

III. NEED FOR RESOURCES

Q. PLEASE DESCRIBE THE FACTORS AFFECTING THE NEED FOR NEW RESOURCES ON THE BLACK HILLS POWER SYSTEM.

A. Two primary factors are driving the need for new resources on the Black Hills Power system. The first is regulations promulgated by the Environmental Protection Agency (EPA) and the resulting retirements of several of Black Hills Power's older coal-fired generating units. The second is the expiration of the Reserve Capacity and Integration Agreement (RCIA) between Black Hills Power and PacifiCorp.

Q. HOW DID BLACK HILLS POWER EVALUATE THE COST OF RETROFITTING THE POWER PLANTS THAT DO NOT COMPLY WITH THE NEW EPA NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR AREA SOURCES: INDUSTRIAL, COMMERCIAL AND INSTITUTIONAL BOILERS (AREA SOURCE RULES)?

A. Black Hills Power contracted with an engineering firm, CH2M HILL, to perform an analysis on several of its smaller coal-fired generating units. The analysis provided an estimate of the capital cost to add emission controls to these units to meet the existing and future air pollution control requirements. These requirements would entail the addition of emission controls, installation of monitoring equipment, restrictions on the quality of coal received and adherence to new operating parameters established during the compliance test. The units evaluated were Neil Simpson Unit 1; Osage Units 1, 2, and 3; and Ben French Unit 1, which are all coal-fired units. After reviewing the study results, including life extension costs, Black Hills Corporation made the decision to retire (and replace) the Neil Simpson 1, Osage 1-3 and Ben French 1 units because that option was more cost effective than retrofitting the units. Ben French, Osage 1-3, and Neil Simpson 1 were officially retired in March of 2014. With these retirements, Black Hills Power's generation capacity was reduced by 71 MW.

Q. WHEN DID THE RCIA EXPIRE AND WHAT IS THE RESULT OF THAT EXPIRATION?

A. The RCIA expired June 30, 2012. Under the RCIA, Black Hills Power could count the Ben French combustion turbine (CT) capacity as 100 MW. This was important because the output from Black Hills Power's older coal-fired generating units is reduced at higher ambient temperatures. Those higher temperatures occur in the summer months of June, July, and August, and coincide with Black Hills Power's peak load periods. The RCIA allowed Black Hills Power the right to call on PacifiCorp for any of the 100 MW that could not be generated by the Ben French CTs. After termination of the RCIA, the Ben French CTs are rated at 72 MW in the summer. This means that the termination of the RCIA has led to a total of 28 MW of capacity that could no longer be counted as Black Hills Power resources available to meet the summer peak demand. This loss of 28 MW of capacity began July 1, 2012.

Q. IN TOTAL, HOW MUCH NET SUMMER CAPACITY WILL BLACK HILLS POWER HAVE RETIRED OR OTHERWISE LOST BETWEEN 2011 AND 2014?

A. Black Hills Power will have lost 99 MW of net summer capacity, calculated as follows:

RCIA expiration	28 MW
Osage retirement	33 MW
Ben French retirement	22 MW
Neil Simpson 1 retirement	16 MW
TOTAL	99 MW

Q. PLEASE DESCRIBE HOW TO FIND THIS 99 MW DECREASE IN RESOURCES IN THE BHP IRP.

A. The Load and Resource Balance provided as Appendix B in the BHP IRP reflects the 28 MW loss due to the expiration of the RCIA and the retirements of Ben French 1 (22 MW) and Neil Simpson 1 (16 MW). A discussion of the retirement of the Osage units (33 MW) is contained in Section 6.2 of the BHP IRP. Because the Osage units were in cold storage at the time the BHP IRP was conducted (and not expected to be reactivated before their 2014 retirement), those 33 MW of capacity are not reflected as available either in Table 6-1 or Appendix B of the BHP IRP.

Q. WHAT PERCENTAGE OF BLACK HILLS POWER'S PEAK DEMAND IS REPRESENTED BY THIS 99 MW OF CAPACITY LOSSES FROM 2012 THROUGH 2014?

A. In the BHP IRP, Black Hills Power's peak demand in 2014 is estimated to be 430 MW (see Table 4-1 of the BHP IRP). Thus, the loss of 99 MW represented 23% of Black Hills Power's 2014 projected peak summer demand.

IV. BLACK HILLS POWER'S INTEGRATED RESOURCE PLAN

Q. PLEASE DESCRIBE THE BHP IRP.

A. The BHP IRP examined the period 2011-2030 and determined the appropriate resources to fill resource needs over that 20-year period. A load forecast of projected peak demands and annual energy consumption was developed. Appropriate assumptions were made for the wide variety of parameters required to model the operation of the generating units. Characteristics required to model all existing resources were confirmed. The analysis considered a range of conventional supply-side resources as well as renewable resources with modeling and operational parameters developed for each. The computer modeling that was conducted consisted of capacity expansion, production costing, sensitivity, and risk analysis. Ventyx, a leading integrated resource planning vendor, performed the computer modeling. The BHP IRP is provided as Exhibit JST-2 to my testimony.

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

A. In addition to the load forecast, 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. Assumptions must also be made for the demand-side management programs put in place during the planning period and their peak demand and annual energy impact.

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

A. Black Hills Power used a coal price forecast that reflects the cost as of May 2011 incurred for fuel delivered to its coal-fired power plants. The coal prices were then escalated to result in the forecast to match the Ventyx reference case, with annual coal escalation averaging about 3% 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 delivered to Black Hills Power's 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.

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

A. Assumptions were required for various financial parameters, including the discount rate, the capital structure, and the levelized fixed charge rates for each of the resource alternatives. The assumptions used for the BHP IRP are shown on Table 3-3.

Q. PLEASE DESCRIBE THE CAPITAL COSTS OF GENERATION RESOURCE ASSUMPTIONS.

A. Black Hills Power used the Ventyx 2011 Spring Reference Case assumptions for capital costs of a variety of generation resources (shown in Tables 6-3 through 6-8). These assumptions include the direct capital costs of coal, a variety of natural gas-fired configurations and renewable generation that are non-site specific. This means that the costs for transmission interconnection, gas fuel supply system installation and ancillary equipment were not included in the capital cost assumptions.

Q. WHAT LEVEL OF PLANNING RESERVE MARGIN WAS USED FOR THE BHP IRP AND HOW WAS THIS LEVEL DETERMINED?

A. Black Hills Power assumed a planning reserve margin of 15% over projected peak demand for this analysis. It was anticipated that the level of reserve margin required by Black Hills Power will not change during the entire 20-year planning horizon evaluated in the BHP IRP.

Q. PLEASE DESCRIBE THE DEMAND-SIDE MANAGEMENT ASSUMPTIONS USED FOR THE BHP IRP.

A. The Black Hills Power Demand-Side Management programs as defined in SD PUC Docket #EL11-002 and approved by the Commission were assumed to be implemented. Those programs and the associated savings in demand and energy are reflected in Section 5.0 of the BHP IRP.

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

A. Conventional resources examined in the BHP IRP include coal-fired capacity, natural gas-fired simple cycle and combined cycle combustion turbines, the purchase of a portion of an existing unit, and firm market purchases.

Q. PLEASE DESCRIBE THE RENEWABLE RESOURCES EXAMINED IN THE COURSE OF PREPARING THE BHP IRP.

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

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 for expected load additions in 2012 through 2016. The trended growth for Black Hills Power is

1.0% for both peak demand and annual energy as shown on Table 4-1 of the BHP IRP. These growth rates do not reflect any significant increases in loads for major industrial customers on the Black Hills Power system as no significant increases were expected at the time the BHP IRP was prepared. As set forth in the BHP IRP, loads for major industrial customers are expected to trend forward without significant decreases or increases throughout the planning horizon.

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 first year that Black Hills Power has a capacity deficit is 2014 as shown on Figure ES-1.

Q. PLEASE BRIEFLY EXPLAIN CAPACITY EXPANSION MODELING.

A. Capacity expansion modeling is a process used to determine the appropriate type, size, and timing for economic resource additions for utilities. The utility's existing generation resources and future resource alternatives are inputted into a capacity expansion model with a forecasted load and other appropriate parameters over the entire planning horizon. The model simulates utility operation, serves the forecasted load with the utility's existing resources, and economically "selects" additional resources from the list of available resource alternatives subject to the planning constraints. The typical criterion for evaluation is the expected present value of revenue requirements (PVRR). Capacity expansion plans are developed for scenarios that vary the assumptions in order to simulate changing market and load conditions.

Q. PLEASE BRIEFLY EXPLAIN PRODUCTION COSTING MODELING.

A. Production cost modeling is a process used to forecast system costs over a specified planning horizon. A production cost model includes an hourly dispatch model, with a load forecast and fixed resources to serve that load. The model simulates a load every hour, then economically serves that load with the available resources, and captures the associated cost.

Q. WHAT SCENARIOS WERE EXAMINED IN THE BHP IRP?

A. As described in Section 7.1 of the BHP IRP, scenarios examined included base, environmental, high gas, low gas, high load, low load, step load, Gillette Top Load, Base with No Firm Market, and No Combined Cycle Conversion Option. What this means is that alternative expansion plans were developed for each scenario, costs were determined for each scenario, and a risk assessment was conducted for each scenario. The resulting optimal expansion plans for each scenario are reflected on Table 7-2 of the BHP IRP. A conversion of a combustion turbine to combined cycle operation was selected as the resource choice for 2014 for each scenario except the scenario in which that resource option was specifically excluded (which is reflected in the BHP IRP as the "No CC Conv Option").

Q. HOW DOES THE 2011 LOAD FORECAST COMPARE TO ACTUALLY EXPERIENCED LOADS IN THE 2011-2013 TIME FRAME?

A. The 2011 peak demand of 452 MW and the 2012 peak demand of 449 MW reached levels that were forecast for the 2017-2018 time frame in the BHP IRP. The 2013 peak demand experienced was lower than forecast in the BHP IRP.

Q. IN WHAT YEAR DID THE BHP IRP FIRST SHOW A CAPACITY DEFICIT?

A. The first year to show a capacity deficit in the BHP IRP is 2014. This capacity deficit is shown graphically in Figure ES-1 on page ES-5 of the BHP IRP.

Q. WHAT GENERATION RESOURCE WAS SELECTED IN THE BHP IRP TO MEET THE 2014 RESOURCE NEED.

A. The resource shown to meet Black Hills Power's 2014 need in the BHP IRP is the conversion of a combustion turbine unit to combined cycle operation. This resource selection results in the addition of 55 MW to the Black Hills Power system. Thus, in order to satisfy reserve margin requirements, the BHP IRP further shows that Black Hills Power would purchase 25 MW of firm power in 2014. Note that as discussed previously in my testimony, 99 MW of resources are no longer available due to retirements and contract expiration. The BHP IRP selects 80 MW of resources in 2014 (less than 99 MW) to meet reserve margin criteria and serve load.

V. SELECTION OF CPGS

Q. DO YOU BELIEVE THAT THE BHP IRP SELECTED A RESOURCE LIKE OR SIMILAR TO CPGS?

A. Yes. The BHP IRP selected a 2014 resource that was the conversion of a simple cycle combustion turbine to combined cycle operation, resulting in the addition of 55 MW to the Black Hills Power system, plus the procurement of 25 MW of firm market power. As stated in the Executive Summary and the Action Plan of the BHP IRP, Black Hills Power's 2014 resource would be procured by "Purchase or otherwise obtain a simple cycle combustion turbine to be converted to combined cycle operation in 2014." The BHP IRP does not specify location or size of that simple cycle combustion turbine other than that it supports a 55 MW addition when converted to combined cycle operation.

Q. DO YOU THINK THAT A SIMPLE CYCLE COMBUSTION TURBINE CONVERTED TO COMBINED CYCLE OPERATION IN CHEYENNE, WYOMING IS WHAT WAS INTENDED BY THE BHP IRP?

A. Yes. I think it is one of several choices available to Black Hills Power. I believe that an IRP identifies the type of resource that makes the most economic sense to add for any given capacity deficit. I further believe that it is up to the utility to make the business decision based on the business case that makes the most sense for that utility's customers. In this instance, an opportunity existed for synergies with a capacity need demonstrated by an affiliate of Black Hills Power –

Cheyenne Light, Fuel & Power. In my opinion, Black Hills Power properly took advantage of those synergies to construct CPGS.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.