BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 16A-______E

IN THE MATTER OF THE APPLICATION OF BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP FOR (1) APPROVAL OF ITS 2016 ELECTRIC RESOURCE PLAN, AND (2) APPROVAL OF ITS 2018-2021 RES COMPLIANCE PLAN.

DIRECT TESTIMONY AND ATTACHMENTS OF

LISA SEAMAN

ON BEHALF OF

BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP

NOTICE OF CONFIDENTIALITY
A PORTION OF THIS DOCUMENT HAS BEEN FILED UNDER SEAL:

Confidential Attachment LS-1, Appendix C, Schedule C-3
(History and Forecasted Economic Data),

Confidential Attachment LS-1, Appendix K, Schedules K-1 to K-16
(Price Forecasts)

and

Highly Confidential Attachment LS-2, Appendix A, Table 9
(Estimated Avoided Costs and Net Incremental Cost of Vestas 1.8MW Wind Facility)

These Attachments are filed under seal pursuant to 4 CCR 723-1-1100 and 1101
Redacted Versions have been filed publicly

June 3, 2016

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Attachments

DIRECT TESTIMONY OF LISA SEAMAN

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lisa Seaman. My business address is 2828 Plant Street, Rapid City, SD 57702.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Manager of Resource Planning for Black Hills Utility Holdings, Inc. ("BHUH"), a wholly-owned subsidiary of Black Hills Corporation ("BHC").

Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS BACKGROUND.

A. I graduated from the South Dakota School of Mines and Technology with a Bachelor of Science degree in Civil Engineering. I joined Black Hills in 2003. My employment history and expertise is provided in Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Black Hills/Colorado Electric Utility Company, LP, d/b/a Black Hills Energy ("Black Hills" or the "Company").

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide information related to Black Hills' Electric Resource Plan ("2016 ERP") and the 2018-2021 Renewable Energy Standard ("RES") Compliance Plan (the "RES Plan"). For the 2016 ERP, I describe how the load forecast was developed, the assumptions used in the modeling for the 2016 ERP, and the 2016 ERP modeling process and results. For the RES Plan, I provide an overview of the RES Plan, the tables in the RES Plan, and the analysis of the retail rate impact of the (1) Company's solar resources; (2) Busch Ranch Wind Project ("Busch Ranch"); (3) Peak View Wind Project; and (4) additional Eligible energy resources selected in modeling conducted in the Company's 2016 ERP.

Q. ARE YOU SPONSORING ANY ATTACHMENTS?

A. Yes. I am sponsoring the following attachments:

- Attachment LS-1 is the Company's 2016 ERP. Mr. Stoffel sponsors Appendices M, N, and O to Attachment LS-1.
- Attachment LS-2 is the RES Plan. Mr. Stoffel sponsors Appendices B, C, D, and E to Attachment LS-2.

Q. WHAT IS THE COMPANY'S PREFERRED PLAN IN THE 2016 ERP?

A. The Company's Preferred Plan ("Base-with-RES Plan") ("Preferred Plan") does not include the addition of any new capacity resources during the Resource Acquisition Period ("RAP"). However, based on bid pricing that was received in the Company's 2014 All-Source Solicitation, the Preferred Plan does include the addition of 60 MW of wind resources in 2019. Based on the 2014 All-Source Solicitation bid prices, the forecasted cost of natural gas, and the forecasted electric prices, the model identified a 60 MW wind resource in 2019 as an economical option for energy. With the acquisition of 60 MW of wind resources in 2019, Black Hills will be able to acquire all of the renewable energy credits ("RECs") necessary to comply with the RES established by C.R.S. § 40-2-124 *et.*

seq. (the "RES Statute") and implemented by Rules 3650 through 3668 (the "RES Rules") through 2025.

Q. WHAT ARE THE PRIMARY ELEMENTS OF THE COMPANY'S PROPOSED RES PLAN?

A. In addition to the proposed acquisition of 60 MW of wind resources in 2019 included in the Base-with-RES Plan, Black Hills is proposing to add 1,500 kW of on-site solar and 2,500 kW of Community Solar Garden ("CSG") annual capacity. The Company is also proposing to lock-down the net incremental costs of these proposed solar programs and to reduce the RESA funding surcharge when the RESA balance becomes positive (beginning in approximately 2020).

III. ASSUMPTIONS FOR THE 2016 ERP

Q. WHAT ASSUMPTIONS WERE REQUIRED TO PREPARE THE 2016 ERP?

A. Assumptions for this 2016 ERP include the following categories: (1) planning period and RAP; (2) reserve margin; (3) load forecast; (4) the operating parameters for the Company's existing and committed resources; (5) the operating parameters and capital costs of potential future conventional, renewable, and Section 123 resources;[1] (6) fuel prices; (7) the cost and amount of seasonal firm market power and economy energy purchases; and (8) financial parameters such as capital structure and discount rate.

IV. THE RAP AND ERP PLANNING PERIOD

[1] Section 123 Resources are defined in C.R.S. § 40-2-123.

Q. WHAT IS THE PLANNING PERIOD OF THE 2016 ERP?

A. The planning period is twenty-five years, from 2016 through 2040 ("ERP Planning Period"). Black Hills selected a twenty-five year planning period to provide a sufficiently long period to evaluate conventional and renewable resources relative to the lives of those resources.

Q. WHAT IS THE RAP OF THE 2016 ERP?

A. The RAP is seven years, 2016 through 2022. The Company chose a seven-year RAP because it complies with Rule 3602(n) and includes the years when Black Hills has identified a need for additional Eligible energy resources to comply with the RES. In addition, Commission Rule 3603(a) requires that utilities file resource plans every four years. The Company will file its next ERP on October 31, 2019.

V. <u>THE LOAD FORECAST</u>

Q. WHO PREPARED THE LOAD FORECAST?

A. The Company completed the load forecast with the assistance of Christensen Associates Energy Consulting, LLC ("Christensen Associates").

Q. WHAT WAS CHRISTENSEN ASSOCIATES' ROLE IN PREPARING THE LOAD FORECAST?

A. Christensen Associates assisted Black Hills staff in the collection and review of required data and the development and review of statistical models that produced the forecasts. They also reviewed the resulting sales and peak demand forecasts.

Q. WHAT METHODOLOGY WAS USED TO PREPARE THE COMPANY'S DEMAND AND ENERGY FORECASTS FOR THE 2016 ERP?

A. The Company used an econometric forecasting methodology to forecast peak demand and energy for the 2016 ERP.

Q. WHY DID THE COMPANY USE AN ECONOMETRIC METHODOLOGY TO DEVELOP THE LOAD FORECAST INSTEAD OF AN END-USE ANAYLSIS?

A. Black Hills, as a comparatively small utility (400 MW peak demand and approximately 2 million MWh of sales annually), believes that the econometric analysis used for the 2016 ERP load forecast adequately estimates the relationship between electricity consumption and the major variables that affect consumption. The econometric methodology used by the Company has been used by other utilities for load forecasting, is relatively inexpensive, and requires less data and fewer assumptions as compared to an end-use analysis. Mr. Hansen, a consultant with Christensen Associates, testifies regarding the details of this load forecasting method.

Q. HOW WAS THE LOAD FORECAST PREPARED?

A. Mr. Daniel Hansen, the consultant that assisted the Company to prepare the load forecast, has filed testimony in this proceeding and describes the methodology used to prepare the system-level peak demand and customer class energy forecasts. The Company collected the required data, performed the modeling, and developed the resulting forecasts under the guidance of Mr. Hansen.

Q. WHAT HISTORICAL DATA WERE USED IN DEVELOPING THE LOAD FORECAST?

A. The major customer class energy forecasts were developed using historical sales and customer count data that has been maintained by the Company in its customer information system, CIS+. Sales data by rate identification code from 2006 through 2015 were gathered, reviewed and aggregated into three major customer classes – residential, commercial, and industrial. For the system-level demand forecast, the Company utilized historical system-level hourly load data that has been maintained in a database since 2006. These data are summarized in Appendix A in the 2016 ERP.

Economic and demographic historical data were obtained from Woods & Poole Economics, Inc. ("W&P") for Pueblo and Fremont Counties for the years 1969 through 2015. In addition, historical electric price data was gathered from the Company's filings in FERC Form 1, page 304, reflecting the average annual price of electricity, on a dollars per kWh basis, for each of Black Hills' customer classes.

Historical weather data were collected from the NOAA National Climatic Data Center's Pueblo Airport weather station. The historical hourly temperature data were used to calculate heating degree days and cooling degree days by using a 60 degree Fahrenheit threshold. The heating degree hours and cooling degree hours were calculated using 50 degree and 70 degree Fahrenheit thresholds, respectively.

Historical economic, demographic, and weather data were used in the peak demand and sales models and are summarized in Appendix A in the 2016 ERP.

Q. DID THE COMPANY USE ADVANCED METERING INFRASTRUCTURE ("AMI") DATA FOR ITS LOAD FORECAST?

A. Yes. The AMI interval consumption data available for 2014 and 2015 has been validated for overall accuracy by comparing the total kilowatt hours of measured consumption by rate code to the total retail kilowatt hours billed in the CIS+ billing system during 2014 and 2015, respectively. With only two years of historical customer-level demand data available from the AMI dataset, the Company determined that a system-level peak demand forecast using system-level hourly load data from the Company's OATI database and Aquila legacy systems would provide a better base for the peak demand forecast. The variance between the two datasets for 2015 is 0.09 percent.

Q. WHAT FORECAST DATA WERE USED IN DEVELOPING THE LOAD FORECAST?

A. Economic and demographic forecast data were used in developing the load forecast. These data were also obtained from W&P for Pueblo and Fremont Counties for the years 2016 through 2050 and are included in Confidential Schedule C-3 of Appendix C of the 2016 ERP.

Q. WHAT INFORMATION REGARDING LARGE CUSTOMER LOAD ADDITIONS AND REDUCTIONS WAS USED IN THE PREPARATION OF THE LOAD FORECAST?

A. The Company periodically reviews the growth plans of the largest customers in its service territory. Through these conversations, the Company identified large customers that have confirmed strategic plans for expansion or already have expansion under construction in the Company's service territory. One of these customers has indicated that they plan to ramp up operations for the first few years of the RAP and then decrease operations by the end of the RAP. Though these large customer anticipated load increases and/or decreases can be uncertain and depend to a great extent on economic conditions, the Company does reflect these load increases/decreases in the load forecast. As a result of these customer communications, the Company is expecting net load gains of approximately five MW for these customers by the end of the RAP (2022). The anticipated additions and reductions in load by year for each of these customers are shown in Table 4-1 in the 2016 ERP.

Q. HOW WAS DEMAND SIDE MANAGEMENT FACTORED INTO THE LOAD FORECAST?

A. Pursuant to C.R.S. § 40-3.2-104, the load forecast was adjusted for assumed reductions in peak demand and annual energy levels due to the effects of the 2016-2018 Demand Side Management Plan ("DSM Plan") which was approved by Decision No. R15-1292 in Proceeding No. 15A-0424E. Black Hills treats DSM as a reduction in load rather than a resource.

The load reductions from the DSM Plan were assumed to be 100 percent coincident, with the result that the projection of kW savings for each program year was subtracted in total from the Company's load forecast. The energy was prorated over the hours of the year to sum to the total energy savings in a program year. Table 3-4 in the 2016 ERP shows the peak demand and annual energy savings due to the effects of the DSM Plan.

Q. PLEASE SUMMARIZE THE FINAL PEAK DEMAND AND SALES FORECASTS THAT WERE USED IN THE 2016 ERP.

A. From 2016 to 2040, system demand, including the effects of the DSM Plan and the anticipated growth plans of large customers' load, is forecast to grow by approximately 0.4 percent. The growth rate over the RAP (2016-2022) was forecasted at 0.1 percent. From 2016 to 2040, energy sales are forecasted to grow by approximately 0.82 percent and the sales growth rate over the RAP (2016-2022) was forecasted at 0.87 percent. These sales growth rates also take into account the effects of the DSM Plan, system losses and the anticipated growth plans of large customers. The peak demand and energy sales forecasts used in the 2016 ERP are shown in Table 4-4 in the 2016 ERP, which is replicated below as Table LS-1.

Table LS-1
Base Load Forecast

Year	Peak Demand* (MW)	Annual Energy* (MWh)
2016	395	2,037,488
2017	395	2,065,684
2018	394	2,084,666
2019	397	2,123,907
2020	401	2,156,324
2021	401	2,157,010
2022	397	2,145,097
2023	398	2,152,368
2024	401	2,173,886
2025	404	2,194,817
2026	406	2,216,110
2027	409	2,237,165
2028	411	2,258,860
2029	414	2,280,431
2030	416	2,300,541
2031	419	2,319,801
2032	421	2,338,428
2033	423	2,356,329
2034	426	2,374,779
2035	428	2,393,173
2036	430	2,411,213
2037	432	2,427,570
2038	435	2,443,671
2039	437	2,460,146
2040	439	2,476,553

*Peak Demand and Annual Energy Forecast values includes impacts of the DSM Plan and losses.

Q. HOW DOES THE 2016 ERP LOAD FORECAST COMPARE TO THE 2013 ERP LOAD FORECAST?

A. The forecast completed by the Company for the 2016 ERP predicts that <u>peak demand growth</u> will be lower than forecasted in the 2013 ERP but that <u>energy consumption</u> will be similar to what was predicted in the 2013 ERP load forecast.

A comparison of actual peak demand and energy sales and the forecasts from the 2013 ERP and the 2016 ERP is shown in 2016 ERP Table 4-9. In the 2013 ERP, the annual energy growth rate was projected at 0.92 percent over the 2013-2037 period, compared to the 0.82 percent growth rate projection in the current plan over the 2016-2040 time period. The annual summer and winter peak demand growth rates over the 2013-2037 planning period was forecasted at 1.09 percent and 1.16 percent, respectively, in the 2013 ERP, compared to the summer and winter 2016 ERP growth rates projected to be 0.44 percent and 0.41 percent, respectively, for the 2016-2040 planning period (previously defined as the ERP Planning Period).

Q. WHY IS THE 2016 ERP LOAD FORECAST LOWER THAN THE 2013 ERP LOAD FORECAST?

A. The primary reasons are: (1) the anticipated effects of the Company's DSM Plan; (2) the sizable revisions to the large customer load projection since the 2013 ERP; and (3) the fact that the econometric analysis used in this 2016 ERP included three additional years of historical data. This is important because the Company's historical system peak occurred in June 2012, the last year of data used in the 2013 ERP load forecast analysis. The lower annual system peaks in 2013, 2014, and 2015 are accounted for in the 2016 ERP load forecast.

Q. HOW WERE INTERRUPTIBLE LOAD CONTRACTS TAKEN INTO ACCOUNT IN THE LOAD FORECAST?

A. The Company included two interruptible loads in its load and resource analysis. The Company has one customer that has a contract pursuant to the Interruptible

Rider Tariff. The terms of this contract provide that the customer will reduce its load by 8 MW when the customer is operating at its maximum load of 33 MW or the customer will reduce its load to 25 MW when operating at a level higher than 25 MW but less than 33 MW. When the customer is operating at a lower level than 33 MW it is not required to reduce its load by the full 8 MW. Based on the terms of this agreement and the customer's load pattern since 2009, Black Hills expects that this customer could supply 5 MW of interruptible load and the Company has incorporated this 5 MW interruptible load in its load and resource balance.

The second customer has a capacity buyback contract for 4.5 MW that the Company expects will terminate. The Company has incorporated this 4.5 MW interruptible load in its load and resource balance through the end of 2017.

Q. WERE HIGH AND LOW LOAD FORECASTS ALSO PREPARED?

A. Yes. In his testimony, Mr. Hansen describes the calculation of confidence intervals that were used to capture some of the forecast uncertainties and to develop forecasts that were used in the high and low load forecast scenarios. 2016 ERP Table 4-5 compares the base, low, and high load forecasts.

VI. <u>THE RESOURCE NEED (LOAD AND RESOURCE BALANCE)</u>

Q. PLEASE DESCRIBE WHAT IS MEANT BY A LOAD AND RESOURCE BALANCE.

A. A load and resource balance looks at the load forecast compared to the Company's existing and committed resources available over the planning period to determine the need for additional resources over that time period. The

Company needs to plan for adequate resources to meet the Company's summer peak demand, plus a planning reserve margin. Such planning will ensure that the Company will be able to meet its peak load obligations in the event of an unforeseen loss of generating resources, extreme weather, or other unexpected conditions. A 15 percent planning reserve margin was used in the 2016 ERP. In his direct testimony filed in this proceeding, Mr. Eric Egge explains why the 15 percent planning reserve margin was used.

Q. PLEASE DESCRIBE THE RESULTS OF THE LOAD AND RESOURCE BALANCE DEVELOPED FOR THE COMPANY.

A. The load and resource balance shows that the Company has sufficient capacity resources to meet customer electricity demand through the RAP. The resource need over the RAP is shown in the following table:

Table LS-2
2016-2022 Load and Resource Balance

	2016	2017	2018	2019	2020	2021	2022
Peak plus 15% planning reserve (MW):	454.6	454.0	452.9	456.0	461.0	460.7	456.6
Total Resources and Purchases (MW):	481.2	485.0	480.5	480.5	480.5	480.5	480.5
Resource Need (MW):	26.5	31.0	27.6	24.5	19.5	19.8	23.9
Resource Need (%):	6.7	7.9	7.0	6.2	4.9	4.9	6.0

Beyond the RAP, Black Hills' load and resource balance shows a small capacity deficit in 2029. This deficit grows by a few megawatts each year until the beginning of 2032, when the Company's purchase power agreement for 200 MW of generation expires.

VII. ASSUMPTIONS REGARDING EXISTING RESOURCES

Q. WHAT OPERATING PARAMETERS ARE REQUIRED FOR MODELING EXISTING CONVENTIONAL UNITS?

A. The operating parameters needed for modeling existing units include: (1) size (MW); (2) heat rate; (3) forced outage rate; (4) fixed and variable operating and maintenance costs; (5) fuel type; (6) annual maintenance requirements; and (7) unit start-up cost.

Q. PLEASE DESCRIBE THE COMPANY'S EXISTING CONVENTIONAL RESOURCES.

A. Black Hills owns:

- Two LMS-100 units (90 MW each) at the Pueblo Airport Generating Station ("PAGS"), and

- Three diesel plants (30 MW total) located in Rocky Ford and Pueblo, Colorado.

Q. ARE THE OPERATING PARAMETERS FOR EXISTING CONVENTIONAL RESOURCES DESCRIBED IN THE 2016 ERP?

A. Yes. Details regarding the operating parameters for Black Hills' existing conventional resources can be found in Table 5-1 of the 2016 ERP. These parameters are based on historical experience gathered from operating the resources.

VIII. ASSUMPTIONS REGARDING EXISTING POWER PURCHASE AGREEMENTS

Q. DOES BLACK HILLS HAVE ANY EXISTING PURCHASE POWER AGREEMENTS ("PPA")?

A. Yes, Black Hills has two long-term firm power PPAs and two non-facility specific agreements.

Q. PLEASE DESCRIBE BLACK HILLS' LONG-TERM PPAS.

Black Hills has a long-term PPA with Black Hills Colorado IPP, LLC to purchase all of the energy and capacity from two 100 MW combined cycle natural gas-fired units located at PAGS ("PAGS PPA"). This PAGS PPA expires in 2031. In addition, Black Hills has a long-term PPA with AltaGas expiring on October 16, 2037, which provides up to 14.5 MW of wind energy and RECs from AltaGas' owned interest in Busch Ranch ("BR PPA").

Q. PLEASE DESCRIBE THE COMPANY'S NON-FACILITY SPECIFIC PPAS.

A. The Company purchases 5 MW of firm capacity and energy through what is referred to as the "MPS Swap." In this agreement, Missouri Public Service supplies capacity and energy to the Western Area Power Administration ("WAPA") on the eastern grid and, in exchange, WAPA supplies an equivalent amount of capacity and energy to the Company in the western grid. This agreement expires on September 30, 2024. In addition, the Company currently has a contract in place with Cargill for the purchase of 50 MW of firm energy during on-peak hours. This contract expires at the end of 2016.

Q. ARE BOTH THE LONG-TERM AND NON-FACILITY SPECIFIC CONTRACTS INCLUDED IN THE MODELING THAT WAS CONDUCTED FOR THE 2016 ERP?

A. Yes, all of the contracts that I described were included in the modeling for the 2016 ERP.

IX. <u>ASSUMPTIONS REGARDING EXISTING RENEWABLE RESOURCES</u>

Q. PLEASE DESCRIBE EXISTING RENEWABLE RESOURCES THAT ARE A PART OF BLACK HILLS' SUPPLY-SIDE PORTFOLIO.

A. Black Hills' existing renewable resources include modest amounts of on-site solar in the form of photovoltaics ("PV solar") that have been installed by customers through the Company's solar programs, a customer-sited 1.8 MW wind turbine, a 120 kW CSG, and Busch Ranch.

Q. DOES THE COMPANY HAVE ANY RENEWABLE RESOURCES THAT ARE UNDER CONSTRUCTION OR HAVE BEEN AUTHORIZED BY THE COMMISSION?

A. Yes. The Peak View Wind Project is currently under construction and is expected to begin commercial operation in November 2016. This 60 MW wind project was approved by the Commission in Decision No. C15-1182.

In Proceeding No. 14A-0535E, the Company's 2015-2017 RES Compliance Plan, the Commission authorized the Company to continue its solar program through on-site solar and CSG offerings in Decision No. C15-1279. The on-site solar capacity authorized for 2016 and 2017 is as follows:

Table LS-3
2016 - 2017 Solar Program - On-Site Solar

System Category	Annual On-Site Solar Program Maximum kW
Small: 0.5 kW up to and including 10 kW	460
Medium Tier 1: 10.001 kW up to and including 30 kW	345
Medium Tier 2: 30.001 kW up to and including 60 kW	245
Medium Tier 3: 60.001 kW up to and including 100 kW	100
Authorized Total kW – Per Year:	**1,150**

The CSG capacity authorized for 2016 and 2017 is as follows:

Table LS-4
2016 - 2017 Solar Program – Community Solar Gardens

Compliance Year	Standard Offer CSG	RFP CSG Maximum
2016	500 kW	2 MW
2017	500 kW	2 MW

Q. WHAT ASSUMPTIONS WERE INCLUDED IN THE MODELING RELATED TO DISTRIBUTED GENERATION RESOURCES?

A. The existing on-site solar, Vestas 1.8 MW wind generator, and CSG facilities were included in the modeling as existing distributed generation resources. The on-site solar and CSG resources authorized for 2016 and 2017 were modeled assuming that the entire capacity offered would be installed.

Q. WHAT ASSUMPTIONS WERE INCLUDED IN THE MODELING RELATED TO BUSCH RANCH?

A. The 29.04 MW Busch Ranch wind project, located in eastern Huerfano County, Colorado, became operational in October 2012. The Company owns half of the turbines and, as mentioned previously, purchases the energy produced by the remaining turbines and the RECs pursuant to the BR PPA. Performance parameters used to model Busch Ranch included a 38.04 percent capacity factor and 23 percent of the facility's nameplate capacity for reserve margin. In other words, the capacity credited to Busch Ranch equals 23 percent of the facility's capacity, or 6.6 MW.

Q. WHAT ASSUMPTIONS WERE INCLUDED IN THE MODELING RELATED TO THE PEAK VIEW WIND PROJECT?

A. The Peak View Wind Project is currently under construction in Huerfano County and Las Animas County, Colorado. The project, when complete, will consist of 34 1.8 MW wind turbines. Performance parameters used to model the Peak View Wind Project included a 41 percent capacity factor and 23 percent of the facility's nameplate capacity for reserve margin.

X. ASSUMPTIONS REGARDING NEW CONVENTIONAL RESOURCES

Q. PLEASE DESCRIBE THE CONVENTIONAL RESOURCES THAT WERE AVAILABLE FOR THE MODEL TO SELECT.

A. The Company contracted with Black & Veatch to complete a busbar study in 2010 to identify the capital cost, fixed and variable operations and maintenance expenses, and emissions rates for the conventional resources available for the model to select for future resource additions. These resources include small combined cycle and simple cycle gas-fired combustion turbines, frame gas combustion turbines, reciprocating gas engines, and small pulverized coal generating units. This study was reviewed and updated to reflect changes in capital costs and operations and maintenance cost trends since 2012. All resources examined in the Black & Veatch study, with the exception of the 2x1 LMS-100 conversion to combined-cycle unit with duct firing, 3x1 GE LM6000 PF Sprint and the 100 MW coal unit, were evaluated as resource options in this 2016 ERP. These available resources are described in Section 5.2 of the 2016 ERP.

Q. DOES THE 2016 ERP INCLUDE TABLES THAT DETAIL THE COST AND OPERATING PARAMETERS FOR THE NATURAL GAS RESOURCES AVAILABLE FOR SELECTION BY THE MODEL?

A. Yes. The operating and cost parameters for combustion turbines, combined cycle units, and the reciprocating engines are found in Tables 5-2, 5-3, and 5-4 of the 2016 ERP.

Q. WHAT WAS THE MODELING ASSUMPTION REGARDING THE DATE WHEN NATURAL GAS-FIRED RESOURCES WOULD BE AVAILABLE?

A. The on-line date for natural gas resources varied depending on the specific technology. In determining the on-line date, the Company considered the time required for a Phase I proceeding, a competitive solicitation process, a Phase II resource acquisition proceeding, and construction time for all resources. The earliest feasible year for the natural gas-fired resource options is included in Tables 5-3, 5-4, and 5-5 of the 2016 ERP.

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XI. ASSUMPTIONS REGARDING AVAILABLE RENEWABLE RESOURCES

Q. WHAT SOLAR RESOURCES WERE AVAILABLE FOR THE MODEL TO SELECT?

A. A 10 MW, 30 MW, and 60 MW PV solar generation facility option was included in the modeling.

Q. WHAT WERE THE MODELING PARAMETERS FOR SOLAR RESOURCES?

A. Black Hills developed performance parameter and cost assumptions for future PV solar resources using data from the bids that were obtained during the Company's 2014 All-Source Solicitation. Parameters used to model PV solar, which assume a PPA for solar energy, are included Table 5-5 of the 2016 ERP. Recent legislation related to Investment Tax Credit levels for 2016 through 2022 were included in the development of the PV solar cost assumptions.

Q. WHAT WIND RESOURCES WERE AVAILABLE FOR THE MODEL TO SELECT?

A. Wind resources were available in blocks of 30 MW and 60 MW in the 2016 ERP and were assumed to be acquired under a PPA.

Q. WHAT WERE THE MODELING PARAMETERS FOR WIND RESOURCES?

A. The Company used data from bids that were obtained during the Company's 2014 All-Source Solicitation to develop future wind resource assumptions. Recent legislation related to production tax credit levels for 2016 through 2022 were included in the development of the wind resource cost assumptions. Parameters used to model wind in the 2016 ERP are shown in Table 5-6 of the 2016 ERP.

Q. WHAT FUTURE SECTION 123 RESOURCES WERE AVAILABLE TO THE MODEL?

A. Two future Section 123 resources were modeled – sodium sulfur batteries and a proposed waste-to-energy project in La Junta, Colorado. Sodium sulfur batteries are an energy storage system that allows utilities to move energy production to the hour during the day when it is most beneficial. Sodium sulfur batteries have the potential to enhance the Company's ability to utilize the energy from wind energy projects by storing the energy generated by the wind turbines during off-peak hours and releasing that energy for use by the Company at other times. The sodium sulfur battery assumptions were gathered from a 2013 State Utility Forecasting Group study.[2] The sodium sulfur battery performance parameters are shown in Table 5-7 of the 2016 ERP.

The modeling parameters for a proposed waste-to-energy project in La Junta were based upon data submitted in a bid in the Company's 2014 All-Source Solicitation. The Company derived modeling parameters for a 10 MW facility,

[2] Carnegie, Rachel, Douglas Gotham, David Nderitu, and Paul Preckel. "Utility Scale Energy Storage Systems." N.p., June 2013. Web.

with an 80 percent capacity factor that would be operational in 2019 with PPA pricing. Because this was the only project of its kind bid into the 2014 All-Source Solicitation the cost parameter used in the 2016 ERP modeling is confidential until this information is made publicly available under Rule 3613(j). The Company expects to file the proposal to make the bids public in June 2016, after the file date of this 2016 ERP.

XII. ASSUMPTIONS REGARDING FUEL PRICES

Q. PLEASE DESCRIBE THE FUEL PRICES ASSUMED FOR NATURAL GAS.

A. The Company used the natural gas price forecasts from ABB's 2015 WECC Fall Reference Case, as adjusted to reflect the basis differential between the Henry Hub and the regional supply centers. The base forecast from the Reference Case was used for the Base-with-RES Plan, Alternative Plan 1 and Alternative Plan 2. For scenario analysis (described in further detail later in this testimony) the Company used ABB's high gas price and low gas price forecasts. In addition, the Company developed a "NYMEX" Price forecast similar to the NYMEX gas price forecast that was developed for Proceeding No. 15A-0502E. This forecast is comprised of the NYMEX natural gas price forecast and Colorado Interstate Gas Company basis forecast for January 1, 2016 through December 31, 2021 that were published as of the close of trading on December 29, 2015. The Company used ABB's base natural gas price forecast for the remainder of the forecast, values for 2022 through 2040. The cost of transportation from the regional supply centers to the Company's service territory was added to the price forecast to reflect the delivered price of natural gas to the Company's generating facilities. Table 3-1 in the 2016 ERP (replicated below as Table LS-5) shows the price ranges of Henry Hub natural gas prices from 2016 through 2040 for the Base-with-RES Plan, Alternative Plan 1 and Alternative Plan 2 and scenarios completed for the 2016 ERP. The same natural gas price forecast for Henry Hub was used for all existing natural gas-fired resources in the modeling.

Table LS-5
Average Annual Henry Hub Annual Gas Price (Real $/MMBtu)

Scenario	2016	2040
Base	$2.94	$13.43
High Gas	$3.47	$19.90
Low Gas	$2.38	$ 7.52
NYMEX Price	$2.55	$13.43
CO_2Tax	$2.90	$13.77

Q. PLEASE EXPLAIN THE FUEL PRICES ASSUMED FOR DIESEL OIL.

A. The oil price forecast from ABB's 2015 WECC Fall Reference Case for diesel was used for the oil price forecast.

XIII. ELECTRIC MARKET PRICE ASSUMPTIONS

Q WHAT TYPES OF MARKET PURCHASE OPTIONS WERE INCLUDED IN THE 2016 ERP MODELING?

A. Black Hills included seasonal firm market purchases and economy energy purchases as market purchase options in the 2016 ERP modeling.

Q. WHAT ASSUMPTIONS WERE MADE REGARDING THE AVAILABILITY OF SEASONAL FIRM MARKET POWER?

A. The 2016 ERP assumes capacity is available for seasonal firm market purchase for 16 hours per day six days a week in June, July and August. The model was allowed to purchase seasonal firm market power in 25 MW blocks, up to 75 MW through 2021, and then adjusted to 50 MW through the remainder of the ERP Planning Period. The direct testimony of Mr. Egge discusses the basis for these assumptions.

Q. PLEASE DESCRIBE THE ASSUMPTIONS FOR THE PRICE OF SEASONAL FIRM MARKET POWER.

A. The ABB WECC 2015 Fall Reference Case energy price forecast for the Palo Verde, Arizona market area, plus a 20 percent premium and transmission adders, was used as a proxy for the cost of seasonal firm market power.

Q. PLEASE DESCRIBE THE ASSUMPTIONS FOR THE AVAILABILITY AND COST OF ECONOMY ENERGY.

A. The model was allowed to purchase non-firm or economy energy up to 150 MW from the market. These purchases reduce the cost of a resource portfolio. The price for economy energy was based on ABB's 2015 WECC Fall Reference Case forecast for the CO-East and Palo Verde (PV) spot markets. The direct testimony of Mr. Egge describes the basis for the assumption that 150 MW of economy energy was appropriate.

XIV. FINANCIAL ASSUMPTIONS

Q. PLEASE DESCRIBE THE FINANCIAL PARAMETERS ASSUMED FOR THIS 2016 ERP.

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. A comprehensive list of financial assumptions and the values used are included in Section 3.5 of the 2016 ERP, and are also discussed in Mr. Stoffel's direct testimony.

Q. WAS THERE AN ASSUMED CARBON TAX INCLUDED IN THE MODELING FOR THE 2016 ERP?

A. No carbon taxes were assumed for any of the plans or scenarios considered in the development of the 2016 ERP with the exception of the Environmental Scenario. For the Environmental Scenario, the Company used the carbon price assumptions from ABB's 2015 WECC Fall Reference Case's CO_2 Tax Scenario, which are included in Confidential Schedule K-3, Appendix K.

Q. PLEASE EXPLAIN HOW THE COMPANY HAS COMPLIED WITH SECTION 3604(l) OF THE ERP RULES WHICH REQUIRES AN ASSESSMENT OF THE COSTS AND BENEFITS OF THE INTEGRATION OF INTERMITTENT RENEWABLE ENERGY RESOURCES ON THE SYSTEM.

A. In 2015, the Company, through its consultant Black & Veatch, undertook a study of the integration costs for intermittent resources including wind and solar. The integration cost components of the additional regulation reserve requirements were separated into the underlying energy and capacity components. The cost of integration relative to energy was derived from a NERC CPS2 analysis which calculated the Automatic Control Error ("ACE") deviation at 10 minute intervals. The cost of regulation was then modeled in the ABB Planning & Risk production cost model to determine the system energy cost differential of providing regulation up and regulation down. Black Hills has around 450 MW of existing resources that can qualify to provide Flex Reserve capacity. Because Black Hills has Flex Reserve capacity sufficient for existing and future intermittent resources, the additional cost to the Company to integrate additional wind and solar if there is no other use for this Flex Reserve capacity is zero. However, Black Hills is subject to Public Service Company of Colorado ("Public Service") Schedule 3 and Schedule 16 tariff rules. The criteria of these FERC tariffs make it difficult for the Company to self-regulate wind capacity. Public Service Schedules 3 and 16 tariff costs were included in the 2016 ERP modeling for wind only. Based on these tariffs, the Company used the wind integration adders shown in Table LS-6 for 30 MW and 60 MW wind options, escalating at 2.5 percent annually, in its 2016 ERP modeling.

Table LS-6
Wind Integration Cost Assumptions ($/MWh)

	2018
30 MW Wind	$4.46
60 MW Wind	$4.66

The study found that the cost of integrating renewable resources varied with the level of penetration of the renewable resources as well as the amount of spinning reserves that needed to be carried to integrate those resources. Table 6-3 in the 2016 ERP report (replicated below as Table LS-7) shows the expected costs for varying penetrations of new wind and solar projects on the Black Hills system. The scenarios represent incremental additions on top of Black Hills' existing Busch Ranch. Thus, the 2019 60 MW wind resource scenario represents a 90 MW total wind analysis.

Table LS-7
Net Integration Costs

Incremental Renewable Scenario	Energy Cost ($/MWh)	Schedule 16 Capacity Cost ($/MWh)	Total ($/MWh)
60 MW Wind	$1.23	$4.25	$5.48
90 MW Wind	$0.95	$4.07	$5.02
120 MW Wind	$0.97	$4.11	$5.08
30 MW Solar	$0.96	-	$0.96
60 MW Solar	$1.22	-	$1.22

Black & Veatch also calculated the accreditable capacity of future levels of wind and solar resources utilizing an Effective Load Carrying Capability ("ELCC") analysis to determine the percentage of the nameplate capacity that can be counted on for reserve margin planning purposes. The accreditable capacity values determined by this analysis were used in the 2016 ERP modeling. Table 6-4 in the 2016 ERP (replicated below as Table LS-8) shows the ELCC for incremental wind and solar additions to the Black Hills system. The Variable Energy Resources study is contained in Appendix F of the 2016 ERP.

Table LS-8
Incremental Wind and Solar ELCC

Type	Total Incremental (MW)	ELCC (%)
Wind	30	30
Wind	60	27
Wind	90	23
Wind	120	20
Wind	150	19
Solar	30	45
Solar	60	37
Solar	90	31
Solar	120	27
Solar	150	23

XV. THE MODELING PROCESS AND RESULTS

Q. PLEASE DESCRIBE THE MODELING PROCESS.

A. The Company performed capacity expansion modeling to determine the expansion plan for each set of assumptions, and production cost modeling to forecast the cost and associated risk exposure of each expansion plan.

Q. WHAT MODELS WERE USED TO COMPLETE THE CAPACITY EXPANSION, PRODUCTION COST AND RISK ANALYSIS?

A. All of the deterministic modeling used in the 2016 ERP analysis was performed by Black Hills using ABB's System Optimizer and Planning and Risk software. The Company retained ABB to provide analytical services in support of the 2016 ERP. ABB reviewed the capacity expansion and production cost modeling completed by the Company. This included verifying input data from ABB's 2015 WECC Fall Power Reference Case and reviewing modeling results. Using the Company's modeling results, ABB used its Strategic Planning *MIDAS Gold*® Corporate Finance module to model the financial and risk simulations.

Q. WHAT IS 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 input into a capacity expansion model with a forecasted load. The model simulates utility operation and "serves" the forecasted load with the utility's existing resources and economically "selects" additional resources from the list of available resource alternatives. The typical criterion for evaluation is the expected present value of revenue requirements ("PVRR") and is subject to meeting load plus reserves and various resource planning constraints (such as Colorado's Renewable Energy Standard).

Q. WHAT IS PRODUCTION COST MODELING?

A. Production cost modeling simulates the hourly operation of the resources available to a utility and is used to forecast system cost and risk exposure. 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. Production cost modeling can also be completed using multiple iterations with changing variables. This form of modeling provides a measure of risk associated with the modeled plan subject to changing variables.

Q. WHAT WERE THE PRIMARY PLANS THAT WERE DEVELOPED IN THE MODELING?

A. There were three primary plans that were developed for the capacity expansion modeling. The plan names and key elements of the plans are shown below and are described in further detail later in my testimony.

Table LS-9
Capacity Expansion Modeling Plans

Plan Name	Key Elements
Base-with-RES Plan	Renewables to comply with RES and achievement of 100% of the DSM Plan
Alternative Plan 1	Base-with-RES Plan plus increasing amounts of renewables or Section 123 resources
Alternative Plan 2	Base-with-RES Plan plus further increase in amounts of renewables and Section 123 resources

Q. PLEASE EXPLAIN WHY THE BASE-WITH-RES PLAN, ALTERNATIVE PLAN 1 AND THE ALTERNATIVE PLAN 2 WERE MODELED.

A. Rule 3604(k) requires that an ERP include at least three alternative plans that can be used to represent the costs and benefits from increasing amounts of renewable energy resources, demand-side resources, or Section 123 resources. One of these alternate plans should represent a baseline case that describes the costs and benefits of the new utility resources required to meet the utility's needs during the planning period, that minimizes the net present value of revenue requirements, and that complies with the Renewable Energy Standard, Rule 3650, as well as with the DSM requirements under C.R.S. § 40-3.2-104. The two other alternate plans represent alternative combinations of resources that meet the same resource needs as the baseline case but include increased amounts of renewable energy resources or Section 123 resources.

Q. HOW MUCH OF THE COMPANY'S RETAIL ELECTRICITY SALES IN COLORADO MUST BE SUPPLIED BY ELIGIBLE ENERGY RESOURCES IN ORDER TO ACHIEVE THE RES?

A The Company is required to generate, or cause to be generated (through purchase or by providing rebates or other form of incentive), Eligible energy resource in the minimum amount of 20 percent of its retail electricity sales in Colorado for each of the compliance years 2016 through 2019 and 30 percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter (Rule 3654(a)).

In conjunction with the above RES, the Company must generate or cause to be generated renewable distributed generation ("DG") at a minimum of: (1) 1.75 percent of its retail electricity sales in Colorado for the compliance year 2016; (2) 2 percent of its retail electricity sales in Colorado for each of the compliance years 2017 through 2019; and (3) 3 percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter (Rule 3655(a)). Finally, at least one-half of the renewable DG requirement must be supplied by retail renewable DG (Rule 3655(b)).

Q. PLEASE DESCRIBE THE BASE-WITH-RES PLAN.

A. The Base-with-RES Plan, which is also the Company's Preferred Plan, was modeled in this 2016 ERP with the constraint that Eligible energy resources necessary to achieve the RES requirement are acquired, and that the goals of the Company's DSM Plan are achieved.

The Base-with-RES Plan meets the resource need and RES requirement over the RAP with the acquisition of a 60 MW wind resource in 2019. Over the remainder of the ERP Planning Period, the Base-with-RES Plan also installs 30 MW of wind in 2026, two LMS-100 natural gas-fired generators in 2032, 60 MW of wind in 2038, and seasonal firm market purchases in 2032 through 2040.

Q. DID THE COMPANY RUN A MODEL THAT EXCLUDED THE RES REQUIREMENT CONSTRAINT?

A. Yes. The Company ran a capacity expansion model that did not include the constraint to acquire Eligible energy resources to meet the RES requirement. Based on the inputs in its modeling, including the bid prices received in the Company's 2014 All-Source Solicitation, the forecasted cost of natural gas and forecasted electric prices, the model identified a 60 MW wind resource in 2019 as an economical option for energy regardless of the RES requirement. This unconstrained model also picked the Preferred Plan. The output of this model run validated that the selection of the 60 MW wind resource in 2019 was based on economics rather than by RES compliance requirements.

Q. PLEASE DESCRIBE THE ALTERNATIVE PLAN 1 AND THE RESOURCES THAT WERE SELECTED IN THIS PLAN FOR THE RAP.

A. The Alternative Plan 1 incorporated the same assumptions as included in the Base-with-RES Plan except the level of required Eligible energy resources and Section 123 resources was increased such that the increased requirement could be fulfilled by adding a single facility. The Alternative Plan 1 meets the resource need and RES requirement over the RAP with the acquisition of a 60 MW wind resource in 2019. Over the remainder of the ERP Planning Period, the Alternative Plan 1 also installs 30 MW of wind in 2026, two LMS-100 natural gas-fired generators in 2032, two 10 MW solar facilities in 2035, 60 MW of wind in 2038, and seasonal firm market purchases in 2032 through 2040. Table 8-2 from the 2016 ERP (replicated below as Table LS-10) shows the resource additions in the Base-with-RES Plan and the two alternative plans.

Q. PLEASE DESCRIBE THE ALTERNATIVE PLAN 2 AND THE RESOURCES THAT WERE SELECTED IN THIS PLAN FOR THE RAP.

A. The Alternative Plan 2 incorporated the same assumptions as included in the Base-with-RES Plan except the RES requirement was increased such that the increased requirement could be fulfilled by adding multiple Eligible energy and Section 123 resource facilities. Both the Alternative Plan 1 and Alternative Plan 2 plans assumed the achievement of 100 percent of the DSM Plan's goals.

The Alternative Plan 2 meets the resource need and RES requirement over the RAP with the acquisition of a 60 MW wind resource in 2019. Over the remainder of the ERP Planning Period, the Alternative Plan 2 also installs 30 MW of wind in 2026, two LMS-100 natural gas-fired generators in 2032, two 10 MW solar facilities in 2035, 60 MW of wind in 2038, 10 MW sodium sulfur batteries in 2039, two 10 MW sodium sulfur batteries in 2040 and seasonal firm market purchases in 2032 through 2040. Table 8-2 from the 2016 ERP (replicated below as Table LS-10) shows the resource additions in the Base-with-RES Plan and the two alternative plans.

Table LS-10
Expansion Plans

Year	Base-with-RES Plan	Alternative Plan 1	Alternative Plan 2
2016			
2017			
2018			
2019	60 MW Wind	60 MW Wind	60 MW Wind
2020			
2021			
2022			
2023			
2024			
2025			
2026	30 MW Wind	30 MW Wind	30 MW Wind
2027			
2028			
2029			
2030			
2031			
2032	(2) LMS100, 25 MW SFMP	(2) LMS100, 25 MW SFMP	(2) LMS100, 25 MW SFMP
2033	25 MW SFMP	25 MW SFMP	25 MW SFMP
2034	25 MW SFMP	25 MW SFMP	25 MW SFMP
2035	25 MW SFMP	(2) 10 MW Solar, 25 MW SFMP	(2) 10 MW Solar, 25 MW SFMP
2036	25 MW SFMP	25 MW SFMP	25 MW SFMP
2037	50 MW SFMP	25 MW SFMP	25 MW SFMP
2038	60 MW Wind, 25 MW SFMP	60 MW Wind, 25 MW SFMP	60 MW Wind, 25 MW SFMP
2039	25 MW SFMP	25 MW SFMP	Sodium Sulfur Battery 10 MW, 25 MW SFMP
2040	25 MW SFMP	25 MW SFMP	(2) Sodium Sulfur Battery 10 MW, 25 MW SFMP
SFMP denotes seasonal firm market power of 25, 50 or 75 MW			

Q. DOES THE BASE-WITH-RES PLAN COMPLY WITH THE RENEWABLE ENERGY STANDARD?

A. In order to determine whether the Base-with-RES Plan complies with RES, it is necessary to consider the net retail rate impact of this plan. Rule 3661(a) of the RES Rules provides that "the net retail rate impact of actions taken by an investor owned QRU ("qualifying retail utility") to comply with the renewable energy standard shall not exceed two percent of the total electric bill annually for each customer of that QRU."[3] This is known as the 2 percent retail rate impact cap.

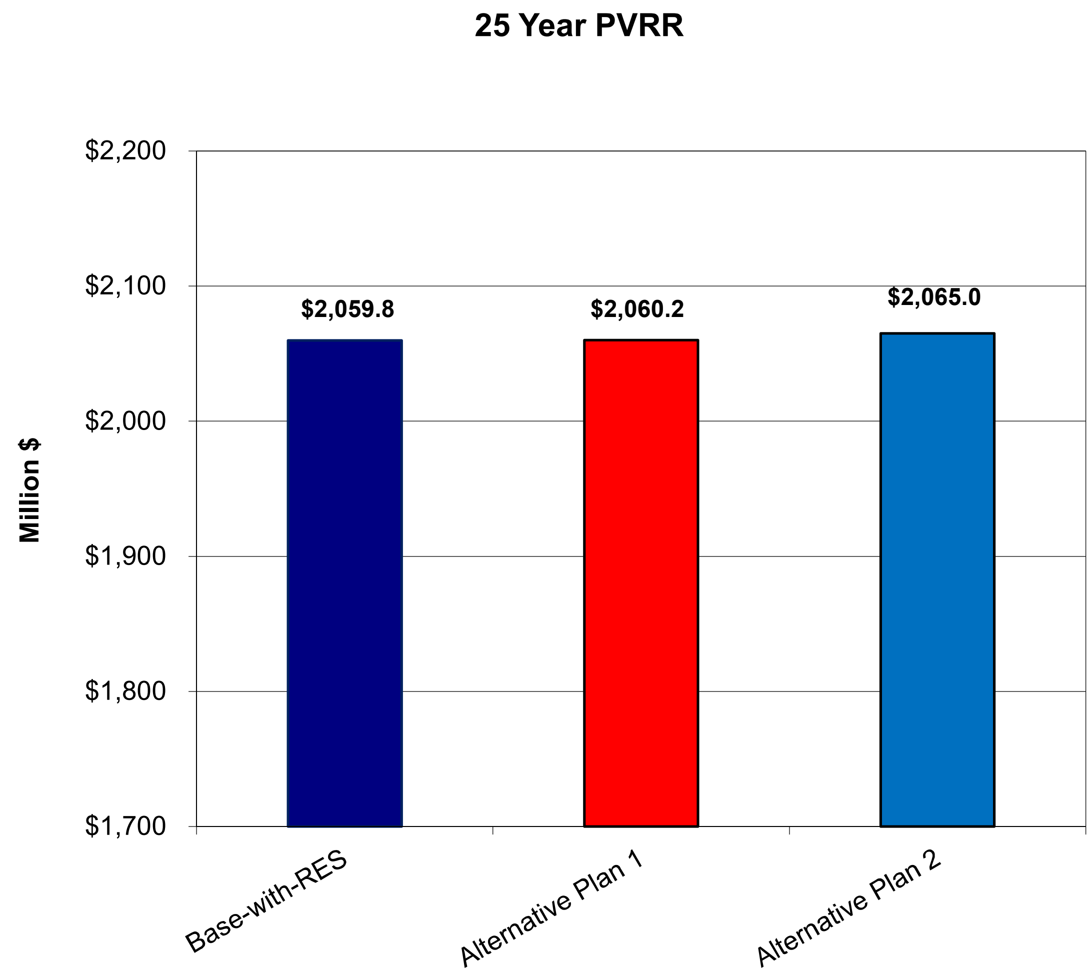
The Company followed the procedures in Rule 3661(h) to determine whether the Base-with-RES Plan can be implemented without exceeding the 2 percent retail rate impact cap. The Company concludes that if it conducts a Phase II solicitation for up to 60 MW of Eligible energy resources and bids offered in the solicitation are comparable to those received in its 2014 All-Source Solicitation, then those resources can be acquired at a cost that is lower than the avoided cost over the ERP Planning Period. In addition, the 2019 60 MW wind resource provides RECs for compliance with the RES. The retail rate impact analysis is described in detail later in my testimony.

Q. WHAT ARE THE PVRRS FOR THE THREE PLANS THE COMPANY MODELED?

A. The deterministic PVRRs for the Base-with-RES Plan, Alternative Plan 1 and Alternative Plan 2, are shown in Figure LS-1 below.

[3] Rule 3661(a) implements § 40-3.2-104(g), C.R.S.

Figure LS-1
Deterministic PVRRs (2016-2040)



Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE ALTERNATIVE 1 AND ALTERNATIVE 2 PLANS?

A. Both the Alternative Plan 1 and Plan 2 do comply with the RES with respect to the Electric resource standard. However, because the Company has sufficient capacity resources to meet demand until the PAGS PPA contract expiration in 2032, and sufficient Eligible energy resources for compliance with the RES until 2026, the model does not add Eligible energy resources or Section 123 resources until later in the ERP Planning Period. Figure LS-1 shows that the PVRR of both

Alternative Plan 1 and Alternative Plan 2 is higher than the Base-with-RES Plan. Importantly, the acquisition of resources beyond the RAP will be decided in subsequent ERPs.

Q. WERE OTHER SCENARIOS MODELED IN ADDITION TO THE PLANS DESCRIBED ABOVE?

A. Yes. Scenario analysis was conducted that included variations in natural gas cost, market electric prices, environmental costs, and load inputs which represent sources of portfolio risk.

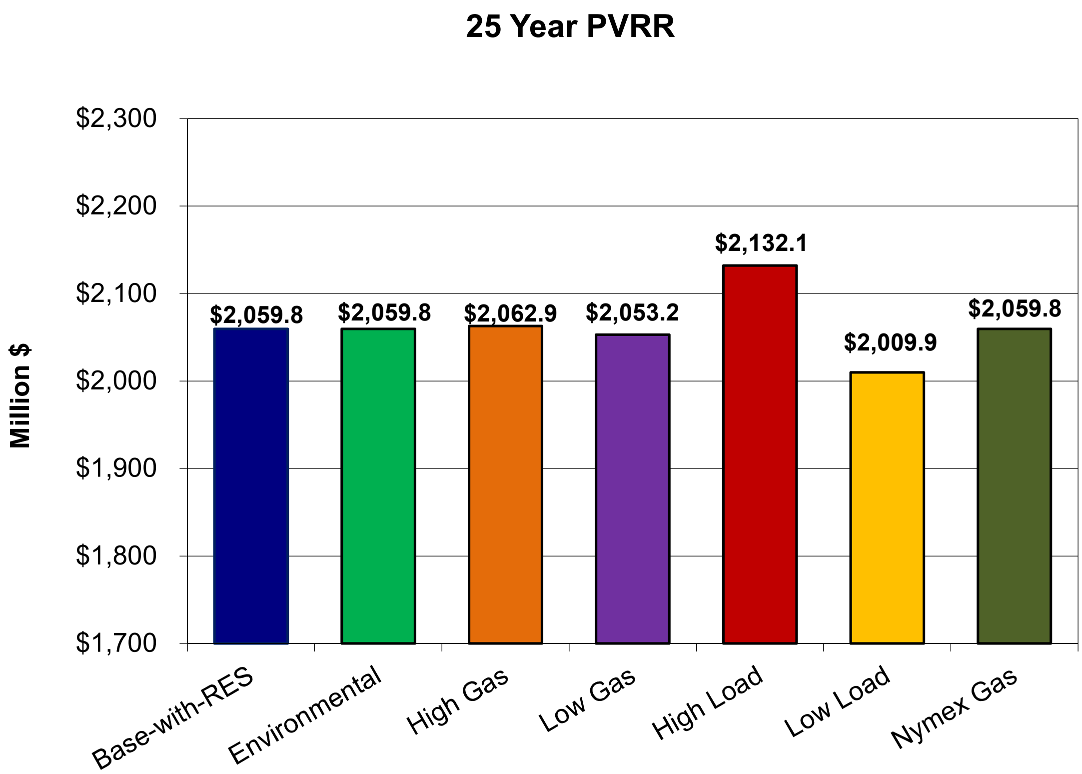
Q. PLEASE DESCRIBE THE SCENARIOS EVALUATED.

A. The scenarios that were modeled included an Environmental Scenario, High Load Scenario, Low Load Scenario, High Gas Scenario, Low Gas Scenario and a NYMEX Gas Price Scenario. Section 8.8 of the 2016 ERP includes brief descriptions of these scenarios.

Q. WHAT WERE THE RESULTS OF THE SCENARIO MODELING?

A. Capacity expansion modeling results (resource portfolios) for these scenarios are shown in Table 8-5 in the 2016 ERP. The PVRRs for the scenario analysis are shown on Figure 8-2 in the 2016 ERP, which is replicated below as Figure LS-2. The PVRR for the Base-with-RES Plan is lower than the cost for any other scenario except for the Low Load and Low Gas Plan.

Figure LS-2
Baseline Scenarios – Deterministic PVRRs (2016-2040)



Source: ABB Advisors

Q. WHAT RISK ANALYSIS WAS DONE FOR THE 2016 ERP?

A. Utilities must plan for future customer needs for electricity in an environment of significant uncertainty. Thus, the analysis conducted for this 2016 ERP examined uncertainty under a variety of possible future conditions. Stochastic analysis and risk profile compilation were among the risk techniques examined.

Q. WHAT IS STOCHASTIC ANALYSIS?

A. The stochastic analysis conducted by ABB used probability theory to assess risk. The analysis examined a wide range of uncertainties that resulted in 50 unique future scenarios for price determination and evaluation of a given portfolio of resources. The scenarios are driven by variations in electricity prices, fuel prices, unit availability, loads and capital costs and take into account statistical distributions, correlations and volatilities. These cumulative probability distributions, also known as risk profiles, were used to visually assess the results of the stochastic analysis. This type of analysis reflects standard industry practice for ERP and resource selection.

Q. WHAT CONCLUSIONS CAN BE DRAWN FROM THE RISK ANALYSIS?

A. ABB provided cumulative probability distributions, or risk profiles, which are shown on Figure 8-3 of the 2016 ERP. In Figure 8-3, with the exception of the Low Load and Low Gas Scenarios, the Base-with-RES Plan is the closest to the left and has the lowest PVRR in all years. These results are reasonable.

XVI. 2016 ERP CONCLUSION

Q. WHAT IS YOUR CONCLUSION RELATED TO THE 2016 ERP?

A. The Company's Preferred Plan is the Base-with-RES Plan, which includes:

- A 60 MW wind resource acquired in 2019;
- 30 MW wind resource installed in 2026;
- Two LMS-100 units installed in 2032;
- A 60 MW wind resource installed in 2038; and
- Seasonal firm market purchases.

Black Hills' Preferred Plan does not include the addition of any new capacity resources during the RAP. Based on the assumptions used in the 2016 ERP analysis, Eligible energy resource bid prices from the Company's 2014 All-

Source Solicitation, the forecasted cost of natural gas and forecasted electric prices, the model identified a 60 MW wind resource in 2019 as an economical option for energy regardless of the RES requirement. Given these results, Black Hills is requesting approval to conduct a Phase II competitive solicitation for the acquisition of up to 60 MW of Eligible energy resources.

XVII. 2018-2021 RES COMPLIANCE PLAN

Q. WHAT IS THE PURPOSE OF A RES COMPLIANCE PLAN?

A. The purpose of a RES compliance plan is to detail how a utility intends to comply with the RES established by the RES Statute and implemented by the RES Rules. Black Hills' 2018-2021 RES Compliance Plan (previously defined as the RES Plan) is attached to my testimony as Attachment LS-2.

Q. PLEASE PROVIDE AN OVERVIEW OF BLACK HILLS' RES PLAN.

A. Black Hills' RES Plan describes how Black Hills met the RES requirements through 2015 and how Black Hills will comply with the RES in 2018 through 2021. The RES Plan describes the Company's proposed retail DG (on-site solar and CSG) programs and a future 60 MW wind resource that was identified in the 2016 ERP. The Compliance Plan describes the retail rate impact calculations for the Company's existing and authorized solar programs, the Vestas 1.8 MW wind turbine, Busch Ranch, the Peak View Wind Project, and the Company's proposed Eligible energy resources for the ten-year compliance period 2018 through 2027. In addition, the RES Plan describes the status of Black Hills' Renewable Energy Standard Adjustment ("RESA").

Q. HOW HAS THE COMPANY MET THE RES REQUIREMENTS THROUGH 2015?

A. Black Hills has been meeting the RES requirements with the following Eligible energy resources:

- On-site solar resources;
- Purchase of solar RECs;
- Small amounts of biomass and biodiesel;
- RECs from the Vestas 1.8 MW wind turbine;
- RECs associated with a load ratio share of Public Service's non-solar renewables (wind RECs);[4]
- RECs from Busch Ranch;
- Purchase of standalone RECs; and
- A 120 kW Community Solar Garden installed in 2015.

XVIII. RES PLAN TABLES

Q. APPENDIX A TO THE RES PLAN INCLUDES SEVERAL TABLES. PLEASE IDENTIFY AND DESCRIBE EACH TABLE IN APPENDIX A TO THE RES PLAN.

- Table 1 provides a forecast of the Company's RES Compliance using existing and authorized Eligible energy resources;
- Table 2 provides a forecast of the Company's Electric resource standard ("ERS") compliance using existing, authorized and proposed Eligible energy resources;

[4] Black Hills was credited with RECs from Public Service's non-solar renewables (wind RECs) in conjunction with the wholesale PPA between Public Service and Black Hills that expired at the end of 2011. The remaining Public Service's wind RECs were retired in 2014.

- Table 3 tracks the receipt and use of retail and wholesale renewable Distributed Generation (DG) RECs;
- Table 4 shows the actual revenues and expenditures that flowed through the RESA from 2006 through 2015;
- Table 5 tracks the status of the RESA funds including existing, authorized and proposed Eligible energy resources;
- Table 6 details the forecasted REC costs associated with the proposed 2018-2021 on-site solar program, proposed CSG program and the proposed 2019 60 MW wind resource;
- Table 7 details the avoided costs for 2018 through 2027 of the proposed 2018-2021 on-site solar program;
- Table 8 includes the avoided costs for 2018 through 2027 of the proposed 2018-2021 CSG program;
- Highly Confidential Table 9 includes the avoided costs for the Vestas 1.8 MW wind turbine 2016 through 2027; and,
- Table 10 includes the avoided costs for 2018 through 2027 of the proposed 60 MW wind resource in 2019.

Q. IS THE COMPANY'S RETAIL SALES FORECAST INCLUDED IN THE RES PLAN?

A. Yes. RES Plan Table 4-01 provides Black Hills' annual retail sales forecast through 2027. This is the sales forecast used in the Company's 2016 ERP. Table 6-01 also shows the amount of Eligible energy resources required to comply with the RES every year through 2027, including the requirements for renewable DG and retail renewable DG. This ten-year period (2018-2027) is the RES Planning Period.

Q. WHAT IS THE PURPOSE OF TABLE 1 IN RES PLAN APPENDIX A?

A. Table 1 in RES Plan Appendix A provides a forecast of the Company's compliance with the ERS during the RES Planning Period using the RECs generated by the Company's existing and authorized Eligible energy resources as well as standalone RECs that were purchased in 2015 and 2016 (Proceeding No. 13A-0445E). Table 1 shows that without the addition of additional Eligible energy resources the Company will not have sufficient RECs to comply with the ERS in 2020 when the ERS requirement increases to 30 percent.

Q. PLEASE DESCRIBE THE PURPOSE OF TABLE 2 IN RES PLAN APPENDIX A.

A. Table 2 in RES Plan Appendix A provides a forecast of the Company's compliance with the ERS using the RECs generated by the Company's existing and authorized Eligible energy resources, standalone RECs that were purchased in 2015 and 2016, and the Eligible energy resources that the Company is proposing in the 2016 ERP, and in this RES Plan. Table 2 shows that the Company will be able to comply with the ERS through the RES Planning Period with the addition of 60 MW of wind in 2019 and the DG resources proposed in the RES.

Q. WHAT IS THE PURPOSE OF TABLE 3 IN RES PLAN APPENDIX A?

A. Table 3 in RES Plan Appendix A tracks the receipt and use of retail and wholesale renewable DG RECs. The retail renewable DG consists of the customer-sited Vestas 1.8 MW wind turbine, customer-sited solar systems, and CSGs. This includes all of the solar systems installed under the Company's solar programs from 2007 through 2015, the 120 kW CSG that was installed in 2015, the systems that were approved in the Company's 2015-2017 RES Plan, and the Company's proposed 2018 and 2021 on-site solar and CSG programs. In addition, Black Hills has a contractual obligation to the winning bidder of a 2007 competitive acquisition process (Rule 3655(d)) to acquire the RECs from a large class (100 kW to 2 MW) solar on-site installation. The associated RECs from that contract are included in Table 3.

The wholesale renewable DG RECs on Table 3 consist of the RECs generated by Busch Ranch, which came on-line in October 2012.

Q. HOW IS THE ACQUISITION OF RECS FUNDED?

A. The Company charges a RESA on customer bills of 2 percent, the maximum amount allowed by the RES Statute and RES Rules. The RESA funds are available to pay for the RECs from Eligible energy resources. Additionally, to the extent Eligible energy resources result in calculated avoided costs, the Company is allowed to recover REC-related costs, up to the amount of the avoided costs, through its Energy Cost Adjustment ("ECA"). This is because the avoided costs are costs that would otherwise flow through the ECA, such as the cost of natural gas fuel for conventional resources and the cost of economy energy purchases. The cost of the Company's 50 percent interest in Busch Ranch is recoverable in base rates, with appropriate adjustments to the ECA and RESA.

Q. WHAT IS THE PURPOSE OF TABLE 4 IN RES PLAN APPENDIX A?

A. The purpose of Table 4 in RES Plan Appendix A is to show the actual revenues and expenditures that flowed through the RESA from 2006 through 2015. Table 4 includes actual retail revenues, actual RESA revenues funded by the 2 percent surcharge, actual costs of the DG solar and wind RECs, and actual program costs. Table 4 also tracks the RESA balance including interest that has accrued on the negative RESA balance, which occurs when the Company advances funds to supplement the funds collected through the RESA surcharge.

Q. WHAT IS THE PURPOSE OF TABLE 5 IN RES PLAN APPENDIX A?

A. The purpose of Table 5 in RES Plan Appendix A is to track the status of the RESA funds and to show how much of the REC costs will be paid for using RESA funds. Table 5 includes the following categories:

- Revenue Forecast;
- Forecast of the RESA Revenues funded by the 2 percent surcharge;
- Forecasted gross costs of the solar and wind RECs;
- Forecasted avoided costs associated with the solar and wind RECs;
- Forecasted net incremental costs of Eligible energy resources (the gross costs minus the avoided costs); and
- Forecasted RESA balance.

The RESA balance is currently negative because the Company has advanced funds to supplement the RESA surcharge.

Q. WHAT IS THE SIGNIFICANCE OF THE NET INCREMENTAL COST/SAVINGS CALCULATIONS?

A. Commission Rule 3661(h)(V) allows the QRU to establish the incremental costs of Eligible energy resources for a set period of time, or "lock down" the costs of Eligible energy resources, enabling the QRU to better estimate the retail rate impact of Eligible energy resources.

Q. HOW ARE THE NET INCREMENTAL COSTS ASSOCIATED WITH ELIGIBLE ENERGY RESOURCES CALCULATED?

A. Rule 3661(h) sets forth the basic method for calculating the incremental costs that result from adding Eligible energy resources to the Black Hills system. The rule requires that the Company determine the net incremental cost of Eligible energy resources by comparing two scenarios to estimate the resource composition of the utility's future electric system and the cost and benefits of that system over the

RES Planning Period. Those benefits are: the avoided costs of (i) fossil fuel expense, (ii) purchased power expense, and (iii) variable O&M production expense. Avoided costs are costs that would have otherwise been incurred, such as the cost of natural gas, if the generation had been supplied by conventional resources rather than Eligible energy resources.

The first scenario is a "RES plan" that reflects the utility's plans and actions to acquire new Eligible energy resources necessary to meet the RES. The second scenario is a "No-RES plan" which reflects the utility's resource plan that replaces the new Eligible energy resources in the RES plan with new non-renewable resources reasonably available. Net incremental cost is determined over a ten-year RES Planning Period and is the calculated difference between the RES and No-RES over that period. The net incremental costs were determined from modeling conducted for the Company's 2016 ERP. Once approved these costs are locked-down and used for the purposes of cost recovery.

Q. WHEN CALCULATING THE RETAIL RATE IMPACT FOR THIS RES PLAN, WHAT RESOURCES WERE INCLUDED IN BOTH THE RES PLAN AND THE NO-RES PLAN?

A. In past proceedings, the Commission locked-down the net incremental cost of several of the Company's Eligible energy resources. The Eligible energy resources included in Table LS-11 below have had their respective incremental costs locked-down on a $/MWh basis, and these resources are included in both the RES and No-RES plans when performing the retail rate impact calculations for the current RES Planning Period.

Table LS-11
Locked-Down Eligible Energy Resources

Resources	Decision No. and Lock-Down Period
Busch Ranch	Decision No. C15-1279 Locked Down from 2015 through 2024
2006 through 2017 Solar Programs	Decision No. C15-1279 Locked Down from 2015 through 2024
Peak View Wind Project	Decision No. C15-1182 Locked Down from 2017 through 2026

Q. PLEASE IDENTIFY THE LOCKED-DOWN COSTS OF THE ELIGIBLE ENERGY RESOURCES THAT HAVE BEEN LOCKED-DOWN IN PRIOR COMMISSION DECISIONS.

A. The resource costs, avoided costs, and net incremental costs locked-down in prior proceedings for the Solar Retail DG Programs,[5] Busch Ranch, and Peak View Wind Project are shown in Table LS-12, Table LS-13, and Table LS-14 below.

[5] The Company notes that, with respect to the Solar Retail DG Programs, the total annual avoided costs and resource costs were calculated using a revised annual production estimate. This estimated annual production was multiplied by the locked-down cost ($/MWh). A revised and simplified methodology for estimating annual production was used.

Table LS-12
2016 – 2024 On-going Annual Net Incremental Costs/(Savings) of Solar Retail DG Programs

Year	Annual Avoided Cost ($/MWh)	Resource Cost ($/MWh)	Net Incremental Cost ($/MWh)
2016	($44.39)	$83.02	$38.63
2017	($48.48)	$82.69	$34.21
2018	($50.76)	$87.78	$37.01
2019	($55.84)	$87.78	$31.94
2020	($54.59)	$87.78	$33.18
2021	($56.89)	$87.78	$30.89
2022	($60.97)	$76.76	$15.79
2023	($64.72)	$76.13	$11.41
2024	($67.26)	$69.29	$2.03

Table LS-13
2016 – 2024 On-going Annual Net Incremental Costs/(Savings) of Busch Ranch Wind Project

Year	Annual Avoided Cost ($/MWh)	Resource Cost ($/MWh)	Annual Net Incremental Cost ($/MWh)
2016	($40.38)	$52.92	$12.54
2017	($43.29)	$51.96	$8.67
2018	($45.47)	$51.04	$5.57
2019	($47.79)	$50.18	$2.39
2020	($51.06)	$49.38	($1.68)
2021	($52.94)	$48.63	($4.31)
2022	($56.40)	$48.33	($8.07)
2023	($58.52)	$48.18	($10.34)
2024	($62.53)	$48.03	($14.50)

Table LS-14
2016 – 2026 On-going Annual Net Incremental Costs/(Savings) of Peak View Wind Project

Year	Annual Avoided Cost ($/MWh)	Resource Cost ($/MWh)	Annual Net Incremental Cost ($/MWh)
2016	($31.19)	$48.68	$17.49
2017	($33.18)	$48.68	$15.50
2018	($35.13)	$43.26	$8.13
2019	($37.70)	$35.52	($2.18)
2020	($40.11)	$30.21	($9.90)
2021	($43.12)	$26.37	($16.75)
2022	($45.68)	$22.52	($23.16)
2023	($48.28)	$19.75	($28.53)
2024	($51.51)	$18.09	($33.42)
2025	($54.10)	$16.42	($37.68)
2026	($57.16)	$14.74	($42.42)

Q. PLEASE DISCUSS THE "LOCK-DOWN" ASSOCIATED WITH BUSCH RANCH.

A. In Decision No. C15-1279, the Commission locked-down the net incremental costs of Busch Ranch. In that proceeding, the Company estimated the integration costs of the project based on results from the Company's 2010 Wind and Solar Integration Study. The integration cost estimated for Busch Ranch was $196,443 per year. Beginning January 1, 2015, Public Service implemented a new Variable Energy Resources ("VER") tariff that is applicable to all entities within its Balancing Authority, including Black Hills. The tariff includes two components: Schedule 3 VER Generation and Frequency Response Ancillary Services charge and Schedule 16 Flex Reserve Service Ancillary Services charge. Black Hills has included these tariff costs in the locked-down Busch Ranch incremental costs as a replacement for the previously modeled $196,443 per year integration cost.

Q. WHAT IS THE PURPOSE OF THE COMMISSION'S LOCK-DOWN RULE (RULE 3661(h)(V))?

A. The purpose of the lock-down rule is to provide the customers and utility with some certainty as to the accounting treatment of the incremental costs of resources already acquired that will be charged against the ECA and RESA accounts during the lock-down years. This facilitates planning for the acquisition of additional renewable resources.

Q. IN THIS PROCEEDING BLACK HILLS IS ASKING THE COMMISSION TO LOCK-DOWN THE NET INCREMENTAL COST OF CERTAIN ELIGIBLE ENERGY RESOURCES. WHAT ELIGIBLE ENERGY RESOURCES ARE INCLUDED IN THIS REQUEST?

A. In this proceeding Black Hills is proposing to lock-down the net incremental costs of the following Eligible energy resources for the time period 2018 through 2023:

- Proposed 2018-2022 on-site solar program;
- Proposed 2018-2022 CSG program; and
- Vestas 1.8 MW Wind facility.[6]

[6] Proceeding 14A-0535E Settlement Agreement. "Black Hills further acknowledges and agrees to calculate and propose an avoided cost amount for the Vestas demonstration wind turbine in its next RES Compliance Plan based on actual data obtained from the Vestas production meter. The Company's next RES Compliance Plan will be filed with the Company's next ERP on or before October 31, 2015 pursuant to Rule 3657(a) and covers the resource acquisition period related to that ERP."

Q. HOW WERE THE AVOIDED COSTS AND NET INCREMENTAL COSTS ASSOCIATED WITH THE PROPOSED 2018-2021 ON-SITE SOLAR PROGRAM CALCULATED?

A. To estimate the avoided costs of the proposed 2018-2021 on-site solar program, the Company compared two model runs:

- **Base-with-RES Plan and Proposed 2018-2021 On-Site Solar Program** - This plan includes the proposed 2018-2021 on-site solar capacity and the Eligible energy resources that have been locked-down in prior proceedings.

- **No-RES Plan** - This model includes all of the Company's existing conventional resources and the Eligible energy resources that have been locked-down in prior proceedings.

The annual forecasted avoided costs, resource costs, and net incremental savings for 2018 through 2027 of the proposed 2018-2021 on-site solar program are set forth in Table 7 of RES Plan Appendix A. The total forecasted avoided costs, resource cost, and net incremental cost of these programs for 2018 through 2027 are shown in the table below.

Table LS-15
2018 through 2027 Total Net Incremental Cost/(Savings) of the proposed 2018-2021 On-Site Solar Programs

Cost	Dollar Amount
Total Forecasted Avoided Costs	$3,083,540
Total Forecasted Costs	$5,054,400
Net Incremental Cost	$1,970,860

This table shows that reliance on solar resources over the ten-year RES Planning Period is approximately $1.97 million more expensive than reliance on conventional generation.

Q. HOW WERE THE AVOIDED COSTS AND NET INCREMENTAL COSTS ASSOCIATED WITH THE PROPOSED 2018-2021 CSG PROGRAM CALCULATED?

A. To determine the net incremental cost of the proposed 2018-2021 CSG program, the following two portfolios from the 2016 ERP were compared:

- **Base-with-RES Plan and Proposed 2018-2021 CSG Program** - This plan includes the proposed 2018-2021 CSG capacity and the Eligible energy resources that have been locked down in prior proceedings.

- **No-RES Plan** - This model includes all of the Company's existing conventional resources and the Eligible energy resources that have been locked down in prior proceedings.

The annual forecasted avoided costs, resource costs, and net incremental savings for 2018 through 2027 of the proposed 2018-2021 CSG program are set forth in Table 8 of RES Plan Appendix A. The total forecasted avoided costs, resource costs, and net incremental savings for the proposed 2018-2021 CSG program for 2018 through 2027 are shown in the table below.

Table LS-16
2018 – 2027 Total Net Incremental Cost/(Savings) of
Proposed 2018-2021 CSG Program

Cost	Dollar Amount
Total Forecasted Avoided Costs	$5,113,670
Total Forecasted Costs	$18,457,551
Net Incremental Cost	$13,343,881

This table shows that the proposed 2018-2021 CSG program costs approximately $13.3 million over the ten-year RES Planning Period as compared to conventional generation.

Q. HOW WERE THE AVOIDED COSTS AND NET INCREMENTAL COSTS ASSOCIATED WITH THE VESTAS 1.8 MW WIND FACILITY CALCULATED?

A. To determine the net incremental cost of the Vestas 1.8 MW Wind Facility, the following two portfolios from the 2016 ERP were compared:

- **Base -with –RES Vestas 1.8 MW Wind Facility** - This plan includes the Vestas 1.8 MW Wind Facility and the Eligible energy resources that have been locked down in prior proceedings.

- **No-RES Plan -** This model includes all of the Company's existing conventional resources and the Eligible energy resources that have been locked down in prior proceedings.

The annual forecasted avoided costs, resource costs, and net incremental savings for 2018 through 2027 of the Vestas 1.8 MW Wind Facility are set forth in Highly Confidential Table 9 of RES Plan Appendix A. The total forecasted avoided costs, resource costs, and net incremental savings for the Vestas 1.8 MW Wind Facility for 2018 through 2027 are shown in the table below.

Table LS-17
2018 – 2027 Total Net Incremental Cost/(Savings) of the Vestas 1.8 MW Wind Facility

Cost	Dollar Amount
Total Forecasted Avoided Costs	$1,658,673
Total Forecasted Costs	$3,102,070
Net Incremental Cost/(Savings)	$1,443,397

This table shows that the Vestas 1.8 MW Wind Facility costs approximately $1.4 million over the ten-year RES Planning Period as compared to conventional generation.

Q. WHAT LOCK-DOWN PERIOD IS THE COMPANY REQUESTING FOR THE PROPOSED 2018-2021 ON-SITE SOLAR AND CSG PROGRAMS AND THE VESTAS 1.8 MW WIND FACILITY?

A. The Company is requesting that the net incremental cost of the proposed on-site solar and CSG programs and the Vestas 1.8 MW Wind Facility be locked down for the period 2018-2024.

Q. WHAT IS THE STATUS OF THE COMPANY'S RESA FUND AS OF THE END OF 2015?

A. As of the end of 2015, the Company had a negative balance of $4,043,450. This means that Black Hills has paid more for its renewables programs, including RECs, than it has collected through the RESA.

XIX. COMPLIANCE WITH THE ERS REQUIREMENTS

Q. WILL THE COMPANY BE ABLE TO MEET THE RETAIL RENEWABLE DG REQUIREMENT FOR THE RES PLANNING PERIOD?

A. Yes. As shown in the retail DG section of Table 3, column 1 (Appendix A to the RES Plan), Black Hills will be able to meet the retail renewable DG requirement of the RES Rules through 2027. It will do so using its carried-forward retail renewable DG (solar) RECs, Vestas 1.8 MW RECs, and the on-going RECs from existing and authorized solar REC obligations and the proposed 2018-2021 on-site solar and CSG programs

Q. WILL THE COMPANY BE ABLE TO MEET THE WHOLESALE RENEWABLE DG REQUIREMENT FOR THE RAP OF THE 2016 ERP?

A. Yes. As shown in the wholesale DG section of Table 3, column p (Appendix A to the RES Plan), Black Hills will be able to meet the remaining renewable DG requirement of the RES Rules through 2027 and beyond with the RECs generated by Busch Ranch.

Q. WILL THE COMPANY BE ABLE TO MEET THE TOTAL RES REQUIREMENTS FOR 2018 THROUGH 2021 WITHOUT ACQUIRING THE RESOURCES PROPOSED IN THE RES PLAN?

A. No. The Company will not have sufficient carried-forward RECs and RECs generated from existing and authorized Eligible energy resources to meet the RES requirements beginning in 2020 when the RES requirement increases to 30 percent. Without the acquisition of additional Eligible energy resources or standalone RECs, Black Hills will only be able to provide 24 percent of its total energy from Eligible energy resources in 2020. This falls short of the 30 percent required in 2020. In 2021, the percentage of energy that Black Hills will be able to provide from existing and authorized Eligible energy resources is projected to be 19 percent.

Q. WHAT ANALYSIS HAS THE COMPANY COMPLETED THAT EVALUATES HOW THE COMPANY CAN MEET THE 30 PERCENT ERS WHICH STARTS IN 2020?

A. As discussed earlier in my testimony, the Company's RES compliance was evaluated in the 2016 ERP.

Q. HOW WAS THE ADDITION OF MORE WIND ENERGY RESOURCES EVALUATED?

A. The addition of more wind energy resources was evaluated in the modeling for the Company's 2016 ERP. Rule 3604(k) requires that the ERP include the descriptions of at least three alternative plans that can be used to model the cost and benefits of the resources necessary to meet the resource need. One of the three plans must represent a baseline case that complies with the RES Rules as well as with the demand side resource requirements under C.R.S. § 40-3.2-104. This is the "Base-with-RES Plan" discussed in the 2016 ERP. To meet the RES requirements over the RAP the capacity expansion modeling in the 2016 ERP selected 60 MW of wind energy in 2019.

Q. DID THE COMPANY PERFORM A RETAIL RATE IMPACT ANALYSIS OF THE 60 MW WIND RESOURCE IN 2019?

A. Yes. The retail rate impact of the Base-with-RES Plan was determined as part of the ERP process. The net incremental cost of the 60 MW wind resource in 2019 was determined by comparing two scenarios in the same manner as discussed earlier in my testimony. To determine the net incremental cost of the 60 MW wind project in 2019 in the Base-with-RES Plan, the following two portfolios were compared:

- **Base-with-RES Plan and 2019 60 MW Wind Resource** - This plan includes the 60 MW Wind resource in 2019 and the Eligible energy resources that have been locked down in prior proceedings.

- **No-RES Plan -** This model includes all of the Company's existing conventional resources and the Eligible energy resources that have been locked down in prior proceedings.

The annual forecasted avoided costs, resource costs and net incremental savings for 2018 through 2027 of the proposed 60 MW wind resource in 2019 are set forth in Table 10 of RES Plan Appendix A. The total forecasted avoided costs, resource cost, and net incremental cost of these programs for 2018 through 2027 are shown in the table below.

Table LS-18
2018 through 2027 Total Net Incremental Cost/(Savings) of the proposed 60 MW Wind Resource in 2019

Cost	Dollar Amount
Total Forecasted Avoided Costs	$74,619,576
Total Forecasted Costs	$76,725,280
Net Incremental Cost	$2,105,704

The RES/No-RES Comparison showed that the addition of 60 MW of wind energy in 2019 would provide approximately $74.6 million of avoided cost savings from 2019 through 2027. However, this resource would cost $76.7 million over that same time period. The addition of 60 MW of wind energy in 2019 would therefore result in a net incremental cost of approximately $2.1 million over the RES Planning Period. Because the Company's RESA balance is forecasted to have a positive balance in 2020 and begin accumulating funds, the Company forecasts that no funds would need to be advanced to the RESA as a result of this resource acquisition. Importantly, over the 25 year 2016 ERP Planning Period, the 60 MW wind resource, as modeled, will save approximately $69.3 million.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A

Statement of Qualifications

Lisa Seaman

Ms. Seaman graduated from the South Dakota School of Mines and Technology with a Bachelor of Science degree in Civil Engineering. Her work experience includes working as a project engineer for Horizons, Inc. from 1987 to 1999. From 1999 to 2003, she worked for the City of Rapid City as the Manager of the GIS Division. She began her career with Black Hills Corporation in 2003 as the Manager of the GIS and CAD Services Department for Black Hills Power. She worked in Black Hills Power's Energy Services Department as an Energy Services Engineer from 2006 through 2008. In 2009, she transferred to Investor Relations and then, in 2011, she accepted the position of Senior Resource Planning Analysis in Resource Planning. Ms. Seaman was named Manager of Resource Planning in January 2013.