BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE COMPLAINT OF ENERGY OF UTAH, LLC AND FALL RIVER SOLAR, LLC AGAINST BLACK HILLS POWER INC. DBA BLACK HILLS ENERGY FOR DETERMINATION OF AVOIDED COSTS	**EL18-038**

DIRECT TESTIMONY AND EXHIBITS

OF

KYLE D. WHITE

ON BEHALF OF

BLACK HILLS POWER, INC.
D/B/A BLACK HILLS ENERGY

May 7, 2019

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I. INTRODUCTION AND QUALIFICATIONS

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Kyle D. White, and my business address is 7001 Mt. Rushmore Road, Rapid City, SD 57702.

Q: PLEASE DESCRIBE YOUR EMPLOYMENT.

A: I am employed by Black Hills Service Company, LLC, a wholly-owned subsidiary of Black Hills Corporation, as Vice President of Regulatory Strategy. My areas of responsibility include providing regulatory strategy and support for the regulated utility subsidiaries of Black Hills Corporation, including Black Hills Power, Inc.

Q: PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS BACKGROUND.

A: I graduated with honors from the University of South Dakota with a Bachelor of Science degree in Business Administration, majoring in management. Several years later, I graduated with a Master's degree in Business Administration, also from the University of South Dakota. My primary areas of focus at Black Hills Corporation have included rate, resource planning, and marketing related work. I have been in my current position as Vice President of Regulatory Strategy since August of 2016, though it previously was associated with Black Hills Utility Holdings, Inc. another wholly owned subsidiary of Black Hills Corporation. During my career, I have been actively involved in preparing applications, testifying and receiving regulatory approvals related to numerous rate cases, changes in rules or regulations, and requests for certificates of public convenience and necessity for both power generation and transmission. I have also led successful efforts to achieve regulatory approvals for utility acquisitions in six states. In addition to on-thejob training, I have attended numerous seminars, trade association meetings and regulatory conferences covering a variety of utility-related subjects.

Q: ON BEHALF OF WHO ARE YOU FILING TESTIMONY?

A: Black Hills Power Inc., d/b/a Black Hills Energy, which is referred to throughout the remainder of my testimony as Black Hills.

II. PURPOSE OF TESTIMONY

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose for my testimony is to explain Black Hills' position on the requirements and dictates of PURPA; South Dakota's implementation of PURPA; and how Black Hills' avoided cost calculation and model satisfy PURPA and align with South Dakota Public Utilities Commission ("Commission") precedent and policies. I address the impact that the various avoided cost methodologies proposed in this case have on Black Hills' retail customers and provide a description of Black Hills' generation resources and load requirements. Finally, I will respond to some of the policy issues, factual matters, and allegations raised in the pre-filed testimony of Mark Klein and Ros Vrba.

III. INTRODUCTION OF WITNESSES

Q: PLEASE INTRODUCE THE BLACK HILLS WITNESSES PROVIDING PRE-FILED DIRECT TESTIMONY IN SUPPORT OF THIS APPLICATION AND BRIEFLY SUMMARIZE THEIR TESTIMONY.

A: The following witnesses, in addition to myself, are providing pre-filed direct testimony on the subjects described herein.

Amanda Thames- Senior Resource Planning Analyst. In her capacity as a resource planning analyst, Amanda Thames utilized the same software modeling system that Black Hills uses for developing resource plans and in its budgeting to forecast an avoided cost at the request of Fall River. Ms. Thames provides a description of the inputs and assumptions which underlie Black Hills' avoided cost modeling, an overview of the modeling process and provides the results of the modeling she performed.

Jim McMahon - Charles River and Associates. Mr. McMahon has spent much of his career in energy working with utilities on issues surrounding resource planning and more generally within the energy industry in assisting with determinations as to whether proposed generation projects are viable from a cost perspective. He has considerable experience with the type of production cost modeling that Black Hills utilizes in determining its avoided costs. He validates Black Hills' modeling, including its inputs and assumptions and rebuts the testimony of Fall River's retained expert, Mark Klein.

IV. EXHIBITS

Q: ARE YOU SPONSERING ANY EXHIBITS TO YOUR TESTIMONY?

A: Yes. I am sponsoring 5 exhibits:

- KDW-1: An illustrative comparison of the impact to Black Hills' retail customers based upon the methodology and avoided cost price proposed by Fall River and the price calculated by Black Hills over the 20 year QF period.
- KDW-2: An illustration of the downward direction of forecast natural gas pricing since 2015.
- KDW-3: An illustration of the downward direction of forecasted market prices for power purchases since 2015.
- KDW-4: May 31, 2018 Correspondence from Black Hills to Fall River regarding its position on the appropriate avoided cost determination methodology.

- KDW-5(a)-5(g): Example correspondence from prior PPA negotiations with Energy of Utah in late spring - early fall 2015.

V. NATURE OF THE PROCEEDING

Q: WHAT IS THE NATURE OF THIS PROCEEDING?

A: The matter before the Commission involves a complaint by Fall River Solar, LLC and its parent, Energy of Utah, LLC in relation to indicative avoided cost pricing that Black Hills has provided for a proposed 80 MW solar project to be located in or near Fall River County, South Dakota. Fall River Solar, LLC is a self-certified Qualified Facility with the Federal Energy Regulatory Commission ("FERC"). Throughout the remainder of my testimony, I will refer to Fall River Solar, LLC and Energy of Utah, LLC collectively as "Fall River" or "Petitioner."

Q: YOU INDICATED THAT THE FALL RIVER PROJECT HAS SELF-CERTIFIED WITH FERC AS A QUALIFIED FACILITY, WHAT DOES THAT MEAN AND WHAT IS ITS SIGNFICANCE?

A: Under the Public Utility Regulatory Policies Act of 1978, ("PURPA") Congress sought to encourage the development of certain types of small power production and cogeneration facilities, known as, Qualifying Facilities or "QFs." Under Section 210 of PURPA, a utility must (1) purchase from a QF any energy and capacity which is made available; (2) sell energy to the QF; and (3) interconnect with the QF. Quite simply, certification with FERC as a QF provides a renewable energy generator, like Fall River, the ability to demand that a utility purchase its energy output and capacity at the utility's avoided cost.

VI. APPLICABLE LEGAL AND REGULATORY FRAMEWORK

Q: HOW DID CONGRESS IMPLEMENT PURPA'S REQUIREMENTS?

A: Congress did not implement PURPA. Rather, through PURPA Section 210, Congress required that FERC adopt rules, which impose a purchase obligation on utilities.[1] It also prohibited FERC from adopting any rules that would provide for a rate that exceeds the "incremental cost" to the utility for the alternate energy.[2] Finally, Congress provided FERC the following guideposts with regard to the rates utilities must pay for QF energy. Those rates:

> (1) Shall be just and reasonable to the electric consumers of the electric utility and in the public interest;
> (2) Shall not discriminate against qualifying co-generators or qualifying small power producers; and
> (3) Shall not require any electric utility to pay more than the "avoided costs" for purchase.[3]

Q: DID FERC PROVIDE ANY ADDITIONAL DEFINITION OF THE PHRASE "AVOIDED COSTS?"

A: Yes, FERC sought to strike a balance between encouraging the development of QF projects, but yet protecting customers from imprudent and unnecessary costs. Consequently, FERC defined "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[4]

[1] Though Order 69, FERC enacted regulations to further assist in defining the obligations under PURPA. Implementation of FERC's rules is reserved to State regulatory authorities, and where applicable, non-regulated electric utilities. *See* Order 69, Federal Register Vol. 45, No. 38 12214, 12216 (February 25, 1980).
[2] *See* 16 USC §824a-3(a).
[3] *See* 16 USC §824a-3(b); 18 CFR §292.304.
[4] *See* 18 CFR §292.101(a)(6).

Q: HAS FERC PROVIDED ANY GUIDANCE ON WHAT HAPPENS IF THE QUALIFIED FACILITY SEEKS TO REQUIRE A UTILITY TO PURCHASE ENERGY WHICH EXCEEDS THE AMOUNT NEEDED TO SERVE ITS LOAD?

A: Yes. There is language in FERC Order 69 that provides some guidance on this particular situation. Specifically, in Order 69, FERC indicated as follows:

> A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy and capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale.[5]

Q: IS THIS LANGUAGE FROM FERC ORDER 69 RELEVANT TO THE CASE BEFORE THE COMMISSION?

A: Yes, I believe that it is especially relevant in light of the Commission's most recent decision on the issue of avoided costs, which is In the Matter of the Complaint by *Consolidated Edison Development, Inc. against Northwestern Corporation, DBA Northwestern Energy For Establishing a Purchase Power Agreement*, Docket No. EL16-021 (December 20, 2017). There, the Commission determined that in a scenario where the utility has backed down its generation to minimum levels and nevertheless there is still more energy available than can be used to serve the utility's load, the utility (there Northwestern) "cannot avoid any costs by purchasing more energy and therefore its avoided costs are zero."[6]

[5] *See* Order 69, Federal Register Vol. 45, No. 38 at 12219.
[6] *Consolidated Edison*, EL16-021 at ¶36.

Q: YOU INDICATED THE LANGUAGE OF ORDER 69 IS RELEVANT ON THE ISSUE OF AVOIDED COSTS OF ENERGY, IS IT RELEVANT WITH REGARD TO THE QUESTION OF AVOIDED COSTS RELATED TO CAPACITY?

A: Yes. I believe it is. The language excerpted from FERC Order 69 speaks to both energy and capacity costs. If PURPA's implementing rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale, a utility should not be required to provide capacity credits or payments when it is not in need of capacity. To conclude otherwise would be to discriminate against the utility's customers in favor of the qualified facility.

Q: HAS THE COMMISSION ENGAGED IN ANY RULEMAKING TO IMPLEMENT PURPA?

A: Yes. The Commission has undertaken some rule making activity, which resulted in Order F-3365. Order F-3365 sets forth some fundamental precepts. In addition, there are two significant decisions from the Commission, which address the contractual requirements for QF contracts and the calculation of avoided costs.

Q: ARE ANY OF THE ISSUES ADDRESSED IN ORDER F-3365 RELEVANT TO THE MATTER BEFORE THE COMMISSION, AND IF SO, PLEASE IDENTIFY THEM?

A: Yes, some of the topics included within the Order remain relevant today. I have summarized those items below:

- The Commission determined that there should not be stated avoided cost rates for QFs with a design capacity of more than 100kW. Instead, rates for QF facilities larger than 100kW are to be developed through negotiations between the QF and the utility.[7]

- "[S]hort and long term QF contracts should include an energy credit based on "the average of the expected hourly incremental avoided costs calculated over the hours in the appropriate on-peak and off-peak hours as defined by the utility."[8]

- Interconnection costs should be assessed to the QF on a non-discriminatory basis.

- Capacity credits should be included in any purchase rates; however, capacity credits "should be based on capacity actually avoided." "[I]f the purchase does not enable a utility to avoid capacity costs, capacity credits should not be allowed."[9]

- To require a utility to pay capacity costs when none are avoided, "would have the effect of requiring the utility to pay twice for the same capacity and would thus impose added and unnecessary costs on the utility's other customers."[10]

Q: YOU DID NOT REFERENCE A PARTICULAR METHODOLOGY FOR CALCULATING THE UTILITY'S AVOIDED ENERGY OR CAPACITY COSTS, DID THE COMMISSION ENDORSE A PARTICULAR METHODOLOGY IN F-3365?

A: No, it did not.

Q: SINCE ORDER F-3365, HAS THE COMMISSION PROVIDED ANY GUIDANCE ON THE APPROPRIATE METHODOLOGY FOR DETERMINING A VERTICALLY INTEGRATED UTILITY'S AVOIDED COST?

A: Yes, *In the Matter of the Complaint by Oak Tree Energy, LLC against Northwestern Energy for Refusing to Enter into a Purchase Power Agreement*, Docket No. 11-006 (May 17, 2013) ("*Oak Tree*") and more recently in *In the Matter of the Complaint by*

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[7] *In the Matter of the Investigation of the Implementation of Certain Requirements of Title II of the Public Utilities Regulatory Policy Act of 1978 Regarding Co-Generation and Power Production*, Decision and Order F-3365 at page 11 (December 14, 1982).
[8] *See id.* at page 12.
[9] *See id.* at page 17.
[10] *See id.* at page 18.

Consolidated Edison Development, Inc. against Northwestern Corporation, DBA Northwestern Energy For Establishing a Purchase Power Agreement, Docket No. EL16-021 (December 20, 2017)("*Consolidated Edison*"), the Commission issued findings on a number of issues that are present in this case, including the appropriate methodology for a smaller vertically integrated utility to use when determining avoided energy costs.

Q: CAN YOU SUMMARIZE THE FINDINGS FROM THESE TWO CASES WHICH ARE RELEVANT AND APPLICABLE TO THE MATTERS AT ISSUE IN THIS PROCEEDING?

A: Yes. In *Oak Tree* and *Consolidated Edison*, the Commission generally endorsed a Hybrid Method for determining avoided energy costs where the utility involved is vertically integrated and primarily relies on its owned generation. The Hybrid Method prices avoided energy costs at the market price when the utility would otherwise be making market purchases, (e.g. when the utility's load is in excess of its own generation resources). Conversely, when the utility's load is less than its baseload generation, avoided costs are those associated with the utility's own internal generation; consequently the avoided cost is represented by the variable cost of operating those generating units.[11] In addition, in *Consolidated Edison*, the Commission recognized that in a third scenario, where the utility's load is less than its available generation resources, running at minimum levels, and its generation cannot be reduced due to operational or contractual constraints, the utility avoids no costs and the avoided energy price is zero.[12] Finally, *Consolidated Edison*, reiterated the concept initially recognized in F-3365 that, while a

[11] *See generally, Consolidated Edison*, EL16-021 at pages 3-4.
[12] *See Consolidated Edison*, EL16-021 at ¶¶22,36.

capacity credit should be afforded to the QF project, that credit should only apply at the point when the utility is actually in need of additional capacity.[13]

VII. BLACK HILLS' EXISTING RESOURCES AND DEMAND REQUIREMENTS.

Q: PLEASE DESCRIBE BLACK HILLS' ELECTRIC OPERATIONS.

A: Black Hills is a vertically integrated electric utility that primarily serves retail customers. At the end of 2018, Black Hills was serving approximately 72,500 electric customers in Western South Dakota, Northeastern Wyoming, and Southeastern Montana. Black Hills' resource portfolio consists of utility-owned thermal generation (primarily coal and natural gas-fueled generation), and long term purchased power contracts. Black Hills has made substantial investments in generating facilities to serve its retail customers and recovers the costs associated with those generation facilities through its retail rates.

Q: CAN YOU PROVIDE A SUMMARY OF THE POWER SUPPLY RESOURCES CURRENTLY AVAILABLE IN BLACK HILLS' RESOURCE PORTFOLIO AND WHICH ARE INCLUDED WITHIN BLACK HILLS' AVOIDED COST MODEL IN THIS CASE?

A: Yes. As shown in more detail in Amanda Thames' exhibit AMT-1, Black Hills' owned thermal generation portfolio can provide up to a maximum of 409 MW of generation.[14] Black Hills is also a party to certain long term contractual power purchase agreements ("PPA"), which are "take or pay" in nature. Those "take or pay" contracts require

[13] *See Consolidated Edison*, EL16-021 at ¶38 (noting that capacity payments would begin at such time that Northwestern showed a need for capacity).

[14] In addition, Black Hills has co-ownership arrangements with other non-affiliated entities. Specifically, Black Hills co-owns the 100 MW Wygen III mine-mouth coal fired power plant with Montana Dakota Utilities ("MDU") and the City of Gillette ("COG"). Black Hills owns 52% of the Wygen III plant (52 MW) and this portion of the capacity is included in the 409 MW of Black Hills' owned generation listed above. MDU owns 25% of that plant and the City of Gillette owns the remaining 23%. The entire capacity of Wygen III is included within the modeling as well as accompanying loads (ownership shares) of MDU and COG.

payment of the full contracted amount whether or not it is used by the utility. Again, as shown on exhibit AMT-1, Black Hills has 3 contractual purchase obligations that are "take or pay" in nature: (1) a PPA for 14.7 MWs of wind generation from the Happy Jack Wind Farm;[15] (2) a PPA for 20 MW of wind generation from the Silver Sage Wind Farm; (3) and a contractual agreement whereby Black Hills must purchase excess energy from its affiliate Cheyenne, Light, Fuel and Power Company ("CLFP GDEMA").[16] Finally, Black Hills has a PPA with Pacificorp (PPA) for up to 50 MW of coal fired power.

Q. IN YOUR CAPACITY AS VICE-PRESIDENT REGULATORY STRATEGY ARE YOU FAMILIAR WITH BLACK HILLS' SHORT AND LONG TERM POWER SALES ACTIVITIES?

A. Yes, I am.

Q: IS IT YOUR UNDERSTANDING THAT BLACK HILLS' LONG TERM CONTRACTUAL SALES ARE INCLUDED WITHIN THE ASSUMPTION UNDERLYING BLACK HILLS' AVOIDED COST MODEL?

A: Yes, that is my understanding.

Q: PLEASE DESCRIBE HOW CONTRACTUAL SALES ARE RELEVANT TO MODELING AVOIDED COST.

A: In certain circumstances, Black Hills has a contractual obligation to serve the load of another entity. In these limited circumstances, the amount of the sales obligation is

[15] Black Hills uses an assumed peak load capacity contribution of 10% on these purchased wind resources; consequently that actual contribution of these resources with regard to energy and capacity (within the model) is less than the total contractual amount listed on AMT-1.

[16] This obligation is contained within an Amended Generation Dispatch and Energy Management Agreement ("GDEMA") between Black Hills Power, Inc. and Cheyenne Light Fuel & Power Company, dated June 14, 2012.

included within the load forecast. Those loads and commitments can be served by available power supply resources, including the QF resource.

Q: GIVEN THE POWER SUPPLY YOU IDENTIFIED, HOW IS BLACK HILLS POSITIONED TO MEET ITS LOAD OBLIGATIONS OVER THE QF CONTRACT PERIOD?

A: Other than intermittent seasonal capacity shortfalls, which are identified later in my testimony and in the testimony of Amanda Thames, Black Hills already has the necessary energy and capacity resources to meet its current and forecasted demand obligations.[17]

VIII. BLACK HILLS' AVOIDED COST METHODOLOGY

Q: DO YOU HAVE A GENERAL UNDERSTANDING OF THE AVOIDED COST METHDOLOGY WHICH BLACK HILLS USED IN PREPARING ITS AVOIDED COST CALCULATION?

A: Yes.

Q: PLEASE PROVIDE A GENERAL OVERVIEW OF THAT METHODOLOGY?

A: Black Hills used a production cost model (which is further described in the testimony of Amanda Thames and James McMahon) to determine the hourly costs of economically serving its system load over the 20 year QF contract period. Black Hills' production cost model forecasts the hourly cost of acquiring energy from a utility's owned or contracted resources, recognizing that some resources have a fixed output ("must-run") and some resources are dispatchable. The production cost model forecasts the hourly dispatch of Black Hills' dispatchable resources by considering how the marginal production cost of

[17] Exhibit AMT-2, which is Black Hills' load and resource balance utilized in its most recent modeling shows these intermittent seasonal capacity shortfalls.

each resource compares to the market price in a given hour. This type of portfolio model, further determines the mix of utility resources and market purchases, needed for the utility to meet its load obligation in each hour. If the total energy available from utility resources is short of the utility's energy requirements, the model determines the market purchases that are needed to balance the utility's system. Black Hills ran this production cost model in two scenarios. In the first scenario, Fall River was not considered a resource within Black Hills' portfolio. In the second scenario, Fall River's 80 MW solar facility was treated as a must-run resource within Black Hills' portfolio.

Q: UNDER WHAT POTENTIAL SUPPLY PORTFOLIO CONDITIONS COULD FALL RIVER BE DELIVERING ENERGY TO BLACK HILLS AND WHAT COSTS ARE AVOIDED IN EACH POTENTIAL SCENARIO?

A: Fall River's 80 MW solar facility could be supplying Black Hills with energy in three potential supply portfolio conditions. The first potential situation is where the model determines Black Hills is "short" on energy, in a given hour, and is making purchases from the market ("Short Case"). Here, the "avoided costs" are the market purchases that would otherwise be made; thus the avoided cost is the market price. The second potential situation is that Black Hills has adequate (or more) supply resources than necessary to serve its system demand, but can back-down or reduce generation to compensate for all (or part) of the 80 MW Fall River resource ("Long Case"). Here, the "avoided costs" are the marginal costs of Black Hills' displaced generation resources. The third potential situation is similar to the second situation. Black Hills has adequate (or more) supply resources than necessary to serve its system demand; however, due to operational or contractual limitations, Black Hills' resources cannot be backed-down or reduced to accommodate the Fall River resource ("Long 2 Case"). In this situation, no costs are avoided; thus the price of avoided energy is zero.

Q: WHY ARE THERE SITUATIONS WHERE BLACK HILLS' RESOURCES CANNOT BE BACKED-DOWN TO ACCOMMODATE THE FALL RIVER RESOURCE?

A: Generally speaking, a vertically integrated utility plans its generation portfolio so that it is able to serve its load, plus consideration of a 15% reserve margin. Stated simply, it is important that a utility's resources and load are roughly matched; this is important for reliability and also to ensure that utility customers are not paying more than what is necessary and prudent to meet their electricity requirements. QF supply resources are not utility-planned, consequently they cannot be considered in utility's resource planning until such time as a project is proposed. Thus, at some level, unless a utility is in need of a resource proximate to the time the QF is set to come on-line, the QF energy is, at some level, excess at the outset. To accommodate (or make room) for the QF energy, utility generating resources need to be "backed-down" or run at lower levels. While thermal generating units do have the ability to be run at levels below their nameplate capacity, there are operational constraints, minimum operating conditions and unit specific factors that can prevent a generating unit from being backed down beyond a certain point.

Q: YOU REFRENCED OPERATIONAL CONSTRAINTS THAT CAN REQUIRE MINIMUM LEVELS OF GENERATION, ARE THERE OTHER TYPES OF CONSTRAINTS ON A UTILITY WHICH COULD PREVENT USE OF THE QF ENERGY TO MEET CUSTOMER DEMAND FOR POWER?

A: Yes. As previously discussed, Black Hills has certain "take or pay" purchased power agreements. Black Hills incurs the costs of those contracts whether or not it uses the energy to meet customer demand and cannot avoid those obligations simply because QF energy is otherwise available. There are 3 agreements of this type in the model: a PPA for 14.7 MW of Wind Generation generated at the Happy Jack Wind Farm; a PPA for 20 MW of Wind Generation generated at the Silver Sage Wind Farm; and a contractual agreement whereby Black Hills must purchase excess energy of Cheyenne, Light, Fuel and Power Company ("CLFP GDEMA"). In addition to the foregoing, Black Hills has a PPA with Pacificorp for up to 50 MW of coal-fired power that has a minimum monthly energy purchase.

Q: HOW ARE THESE TAKE OR PAY CONTRACTS TREATED WITHIN THE PRODUCTION COST MODEL?

A: As further described in the testimony of Amanda Thames, these contractual purchases are set as "must-run" within the model, in other words the model is not given a choice but to dispatch these resources and they are dispatched to serve the load without regard to the economic aspect of the dispatch.

Q: IN DESCRIBING THE CONTRACTUAL AGREEMENTS, WHICH ARE TREATED AS "MUST-RUN," YOU REFERENCED THE CLFP GDEMA CONTRACT, HOW DID BLACK HILLS DETERMINE HOW MUCH ENERGY AND CAPACITY SHOULD BE ATTRIBUTABLE TO THE CLFP AFFILIATE CONTRACT?

A: The Fall River model is linked to a Cheyenne Light, Fuel and Power Company ("CLFP") production cost model. The CLFP production cost model identifies CLFP excess energy.

The excess energy then flows to Black Hills as a must-take contract. The model does not include any capacity contribution for the CLFP GDEMA.

Q: DOES THE METHODOLGY BLACK HILLS USED TO DETERMINE THE ENERGY COMPONENT OF ITS AVOIDED COST COMPORT WITH COMMISSION PRECEDENT AND, IF SO, HOW?

A: Yes it does. Black Hills sought to incorporate the Commission's key findings from *Consolidated Edison* into its avoided cost modeling methodology. Namely, the modeling identifies the three potential supply conditions under which a QF could provide energy: the Short Case, the Long Case and Long 2 Case. Additionally, similar to the process endorsed in *Consolidated Edison*, the energy pricing for QF energy in each scenario correlates to the costs the utility would have encountered "but for the purchase from the qualifying facility." In the Short Case, those avoided costs are the avoided market purchases. In the Long Case, those avoided costs are the variable operating costs associated with the generating resources which are being "backed-down." Finally, in the Long 2 Case, as recognized by the Commission in *Consolidated Edison* the avoided cost is zero.

Q: WHEN DID BLACK HILLS START MODELING AVOIDED COSTS IN THE MANNER DESCRIBED ABOVE?

A: After issuance of the *Consolidated Edison* decision, which was issued in December of 2017.

Q: WHAT IS FALL RIVER'S POSITION AS TO AVOIDED COSTS IN THE LONG 2 CASE?

A Fall River apparently disagrees with Commission's decision in *Consolidated Edison* and urges that the order does not bind the Commission or the parties. It appears that Fall River is urging that a QF delivering unusable energy should be paid forecasted market prices for that energy.

Q: IF THE COMMISSION WERE TO ALLOW FALL RIVER TO COLLECT THE FORECASTED MARKET PRICE IN THE "LONG 2 CASE," HOW WOULD BLACK HILLS' CUSTOMERS BE IMPACTED?

A: If the Commission reversed its findings in *Consolidated Edison*, and required payment of the forecasted market prices in the Long 2 case, it would be requiring Black Hills to act as a conduit to the market. Moreover, Black Hills' customers would act as a fixed price guarantor for the benefit of the QF, regardless of what the market price may be at the time of delivery. There is no benefit to Black Hills' customers in being the 20-year market maker for the forecasted excess generation of the Fall River solar project.

Q: ARE YOU FAMILAR WITH THE AVOIDED COST PRICING THAT BLACK HILLS HAS GIVEN TO FALL RIVER?

A: Yes, I am. Fall River has been given three different prices over the course of the Parties' negotiations and during this dispute. In April of 2018, Fall River was provided with modeling outputs and an avoided cost price after a request was made in February of 2018. That model and avoided cost price was based on the ABB 2017 Fall Reference Case for commodity pricing (natural gas, purchased power and oil) and included 52 MW of solar energy production from a potential utility-owned solar project referred to commonly (and in Fall River's complaint) as SD Sun. The 20 year levelized avoided cost price provided was $17.02 per MWh. After additional discussions between the Parties, Black Hills provided updated modeling outputs and avoided cost pricing in August of 2018. These outputs included a reduction in the amount of energy anticipated from a potential utility-owned solar project from 52MW to 20MW and also utilized the Spring 2018 ABB Reference Case for those same commodity prices. This updated modeling resulted in a 20 year levelized avoided cost price of $21.77 per MWh. Subsequently, a letter was sent to Fall River's counsel on March 1, 2019, advising Fall River that, because Black Hills had decided not to build the SD Sun Project at that time, Black Hills would be providing an updated avoided cost calculation that did not include the SD Sun Project in the model assumptions. On March 8, 2019, Black Hills provided Fall River with updated model outputs, which resulted after removal of the SD Sun Project. The 20 year levelized avoided cost price provided on March 8, 2019 was $24.95 per MWh.

Q: DOES THE $24.95 PER MWh AVOIDED COST PRICE THAT BLACK HILLS OFFERED ON MARCH 8, 2019 INCLUDE CONSIDERATION FOR AVOIDED CAPACITY COSTS?

A: Yes, all three of the prices referenced above included consideration for the only type of "capacity" cost actually avoided by the Fall River project which is intermittent seasonal firm energy purchases.

Q: PLEASE EXPLAIN WHY BLACK HILLS' MODEL ONLY CONSIDERS AVOIDANCE OF SEASONAL FIRM ENERGY PURCHASES FOR PURPOSES OF ASSESSING ANY CAPACITY CONTRIBUTION?

A: Black Hills is not projecting a need for capacity resources during the QF contract period. As explained earlier in my testimony and in that of James McMahon, Black Hills already has the necessary energy and capacity resources to meet its current and forecasted demand obligations. This is especially true given modest projections for load growth over the QF contract period, which are reflected in Exhibit AMT- 2, which was provided with the testimony of Amanda Thames.

Q: PLEASE EXPLAIN HOW BLACK HILLS' MODELING INCLUDES COMPENSATION FOR CAPACITY CONTRIBUTIONS?

A: Black Hills' load and resource balance determines at which points, during the 20 year QF contract period it is short capacity. These identified capacity needs are imported into the production cost model. As demonstrated in Exhibits AMT-2, 5 and 8, which were provided with the testimony of Amanda Thames, Black Hills only experiences intermittent capacity short-falls in certain months and certain years during the 20 year QF contract period. These intermittent shortfalls generally occur in the annual peak month of July. Historically, Black Hills has addressed this type of capacity shortfall with firm purchases of a 6 x 16 (6 days week, 16 hours a day) firm energy product to provide for intermittent summer capacity shortfalls. In light of the foregoing, Black Hills forecasts the costs associated with these capacity shortfalls starting with a 6 x 16 on-peak energy contract at Palo Verde (PV) as a basis and adding a firm capacity premium of 20%. The avoided costs of these seasonal firm purchases, as forecasted in the model, are included within the total $24.95 per MWh avoided cost price.[18]

Q: DOES THE COMMISSION'S PRIOR RULE-MAKING OR PRECEDENT REQUIRE CAPACITY PAYMENTS FOR A 20 YEAR TERM, REGARDLESS OF A UTILITY'S ACTUAL NEED FOR THAT CAPACITY?

[18] This same method for quantifying and pricing avoided seasonal firm energy purchases was used all three of Black Hills avoided cost models.

A: No, it does not. On the contrary, the Commission in F-3365, the Commission determined that, while capacity credits should be included in QF purchase rates, any capacity credits should be based on capacity "actually avoided." It further explained that, if a QF purchase would not allow the utility to avoid capacity costs, no such credits should be included. Finally, the Commission emphasized that, if a utility were required to make capacity payments regardless of need, it would have the effect of requiring the utility to pay twice for the same capacity and would unduly burden the utility's customers. To this end, in cases arising after F-3365, the Commission has delayed the institution of capacity payments or credits until such time as the utility actually has a need for that capacity.[19]

Q: DOES THE POSITION TAKEN BY THE COMMISSION IN F-3365 ALLIGN WITH RELEVANT FERC RULES?

A: Yes, it does. In Order 69, FERC recognized there would be situations where the QF did not allow any capacity to be deferred and thus there would be no avoided capacity cost.[20] It also recognized that the nature of the capacity deferred could be "seasonal" or "peak" in nature,[21] could involve avoidance of a new plant,[22] or could involve making fewer firm power purchases.[23]

Q: DO YOU HAVE AN UNDERSTANDING AS TO FALL RIVER'S POSITION ON CAPACITY PAYMENTS?

A: Yes, I do. First, Fall River's witness Mark Klein urges that Black Hills' proposed avoided cost provides no consideration for capacity. He is incorrect. Second, Fall River asks the

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[19] *See Consolidated Edison*, EL16-021, at ¶38.
[20] *See* Order 69, Fed. Reg. Vol 45, No. 38 at 12225.
[21] *See* Order 69, Federal Register, Vol. 45, No. 38 at 12225.
[22] *Id.* at 12226.
[23] *See Id.*

Commission to utilize a "solar proxy" method for determining avoided capacity payments. Specifically, Fall River urges that, because Black Hills had considered building a solar project with a similar in service date ("SD Sun Project,") the "all-in" costs of constructing and operating that project should be used as a proxy in determining the capacity costs avoided. Finally, it appears that Fall River urges for a capacity payment for the entire QF contract period.

Q: SHOULD THE COMMISSION ACCEPT FALL RIVER'S PROPOSED METHODOLOGY FOR DETERMINING CAPACITY CREDIT?

A: No, it should not. The Commission should reject Fall River's proposed method for determining capacity credit for a number of reasons. First, the Commission has never endorsed a methodology which would use a "renewable proxy" for determining avoided capacity costs. Second, Black Hills has notified Fall River and Staff that it is not planning to build the proposed solar project at this time. Thus, pricing avoided capacity based upon that theoretical facility would not be reflective of costs that the utility (and its customers) would have encountered. Third, Fall River's approach assumes that the proposed SD Sun project was planned to fill a capacity need or deficit; construction of this project would not have been driven by a capacity need; thus it would be inappropriate to utilize it to model avoided capacity costs. Third, Fall River asserts that it should be paid capacity for capacity for the entire 80 MW of its proposed project even though at no time did Black Hills consider building a solar project of this scale. Finally, it appears that Fall River is attempting to develop an avoided cost methodology that would justify construction of its project. For these reasons, and because the methodology utilized by Black Hills more closely aligns with the costs that Black Hills may actually avoid in light of the QF purchase, the Commission should reject Fall River's proposed capacity methodology.

Q: DO THE AVOIDED COST PRICES BLACK HILLS HAS PROVIDED INCLUDE CONSIDERATION FOR COSTS OF AVOIDED TRANSMISSION?

A: Yes.

Q: WHAT IS THE OVERALL IMPACT ON CUSTOMERS BETWEEN THE METHODOLGY UTILIZED BY BLACK HILLS AND THAT UTILIZED BY FALL RIVER?

A: Comparing the 20 year levelized avoided cost price provided by Black Hills in March of 2019 ($24.95 per MWh) and the 20 year levelized avoided cost price referenced in the testimony and report of Mark Klein, results in approximate 86 million dollar increase in costs to Black Hills' customers over the proposed QF PPA term. A direct year by year comparison can be found at Exhibit KDW-1.

Q: HOW DID YOU CALCULATE THE COSTS CONTAINED IN EXHIBIT KDW-1?

A: KDW-1 simply reflects the Parties' respective avoided cost pricing against Fall River's production profile over the 20 year QF contract period.

Q: IN PREPARING THIS TESTIMONY, HAVE YOU DISCOVERED ANYTHING THAT YOU BELIEVE SHOULD BE CHANGED WITH REGARD TO THE MODELING ACCOMPLISHED AND AVOIDED COSTS THAT HAVE BEEN PROVIDED TO FALL RIVER?

A: Yes, I have. In preparing this testimony and reviewing the previous modeling work accomplished, Black Hills determined that it did not apply an inflation component to the commodity prices (natural gas, purchased power, and oil prices) within the ABB forecasts. Black Hills has determined that the ABB forecasts are stated in real dollars, rather than nominal dollars. Consequently, it appears reasonable to consider inflation before applying any discount factor. Black Hills intends to apply a 1.5% inflation factor, which was utilized in an Integrated Resource Plan recently filed with the Wyoming Public Service Commission on behalf of affiliate Cheyenne Light, Fuel and Power Company. In addition, though the difference is slight, it appears an outdated discount factor was utilized. The 7.41% discount factor that was used was derived from Black Hills' 2011 IRP. Since that time, the Commission has authorized a weighted average cost of capital of 7.76%. Thus, the discount factor should have reflected this change. Black Hills is working to update its modeling outputs and avoided cost price with these two changes and will provide them as a supplement to its testimony and exhibits.

IX. RESPONSE TO FALL RIVER'S TESTIMONY

Q: HAVE YOU REVIEWED THE TESTIMONY PROVIDED BY ROS VRBA AND MARK KLEIN FILED ON BEHALF OF FALL RIVER?

A: Yes.

Q: WHAT IS FALL RIVER'S POSITION AS TO THE TIMING OF ANY LEGALLY ENFORCEABLE OBLIGATION OR "LEO" DATE?

A: The testimony includes a number of references to the issue of the applicable LEO date. There is a statement that Fall River, Black Hills and Staff has stipulated to a LEO date with that date being September 6, 2018. Mr. Vrba also testified to a potentially earlier LEO date (June 8, 2018), which was contemporaneous with an offer by Fall River to enter into a PPA with Black Hills for a 20 year levelized cost of $41.69 per MWh.

Q: WHAT IS BLACK HILLS' POSITION ON THE LEO DATE?

A: I am aware that, early in this litigation (Fall of 2018), Black Hills expressed a willingness to enter into a stipulation on the LEO date and that the date referenced therein was September 6, 2018. I am also aware that there were a number of subsequent discussions between lawyers for Fall River and Black Hills as to generation additions or purchased power additions to Black Hills portfolio after September 6, 2018. It does not appear, from my review of the docket, that those discussions came to a close or that the three Parties to the current litigation entered into a formal written stipulation on the LEO date. Staff's position on the LEO is currently unclear. Moreover, Black Hills recently received testimony and discovery from Fall River which includes some further information as to Fall River's avoided cost offers in June and August 2018. In June of 2018, Fall River apparently used an avoided cost price it believed to be associated with a prior solar project (SD Sun II), rather than an analysis of the avoided costs based on methodology recognized by the Commission or current market conditions.[24] In August 2018, Fall River provided a different avoided cost, which expressly rejected the Long 2 case as described herein. Because Fall River has not recognized the methodology in *Consolidated Edison*, it has not committed to deliver energy, capacity, or both in a manner that is reflective of the utility's avoided cost and it should not be deemed to have triggered a Legally Enforceable Obligation or LEO. For these reasons, Black Hills believes the Commission should adjudicate an appropriate LEO date, if any. At a minimum, additional discovery on the LEO should be accomplished.

[24] Fall River's Responses to Black Hills First Set of Data Requests, Data Request 1-10 and DR 1-11. See also Vrba testimony at 11-12.

Q: HAVE YOU REVIEWED CORRESPONDENCE AND NEGOTIATION BETWEEN THE PARTIES FROM FEBRUARY 2018 THROUGH SEPTEMBER 2018?

A: Yes.

Q: CAN YOU SUMMARIZE THE POSITIONS OF THE PARTIES DURING THESE 2018 DISCUSSIONS AND NEGOTIATIONS?

A: Yes. Black Hills took the position that it utilized the methodology identified by the Commission in the *Consolidated Edison* decision (Docket E16-021). See Exhibit KDW-4. On the other hand, Fall River urged that *Consolidated Edison* methodology had not be "approved" for Black Hills and that the methodology should not apply outside of the SPP market (or potentially another organized market).[25]

Q: DO YOU THINK THAT *CONSOLIDATED EDISON'S* RECOGNITION OF THE POTENTIAL THAT, AT TIMES, A UTILITY WILL AVOID NO COSTS THROUGH RECEIPT OF QF ENERGY SHOULD BE LIMITED TO AN ORGANIZED MARKET STRUCTURE?

A: No, I do not. To the contrary, this recognition is even more important for the protection of customers in bilateral markets, as the ability to market any excess unusable energy is wholly dependent on marketing employees being able to negotiate a sale of the energy with a willing buyer at a price in excess of what was paid for the QF energy.

Q: FALL RIVER'S EXPERT WITNESS HAS OFFERED TESTIMONY THAT BLACK HILLS HAS CONTRACTUAL AGREEMENTS TO SELL ALL OF THE

[25] *See* Testimony of Ros Vrba, Exhibit D.

ELECTRICITY THAT IT GENERATES WHEN IT IS IN A LONG SITUATION, DO YOU AGREE WITH THAT STATEMENT?

A: No, I do not. As explained in Black Hills' discovery responses, it does not have any power sales agreement whereby another party is mandated to purchase all of Black Hills excess energy. Instead, Black Hills must attempt to negotiate bilateral sales on a case-by-case basis in such a situation.

Q: IN HIS TESTIMONY AND EXHIBITS D AND F, MR. VRBA REFERENCES A CHANGE IN BLACK HILLS' PROPOSED AVOIDED COST PRICES SINCE PRIOR PPAs AND URGES THAT THIS DEMONSTRATES ERRONOEUS MODELING BY BLACK HILLS, HAS AVOIDED COST PPA PRICING CHANGED SINCE 2015 AND DO YOU HAVE ANY OPINIONS AS TO WHY?

A: Yes, Black Hills' avoided cost pricing has changed since 2015. A number of factors can result in a change to the outputs associated with avoided cost modeling. Two factors at play in this matter include changes in pricing forecasts for key inputs (including natural gas and purchased power) and changes driven by inclusion of the Long 2 - zero dollar avoided cost consideration in light of the decision in *Consolidated Edison*. In looking at Exhibits KDW-2 and KDW-3, it is clear that between Fall 2015 and Spring 2018, there is a clear downward trend in the annual average natural gas and purchase power forecast pricing. Lower natural gas and purchased power pricing forecasts impact the avoided cost pricing in the Short Case due to lower market prices, which are driven largely by natural gas pricing. Lower natural gas prices can also drivc-down avoidcd costs in thc Long Case if the marginal generating unit is a natural gas-fired unit. In addition to the foregoing, Black Hills implemented the Long 2 zero dollar cost consideration after the *Consolidated Edison*, which would also have some impact on the avoided cost price.

Q: HAVE YOU REVIEWED THE TESTIMONY OF ROS VRBA, PARTICULARLY WITH REGARD TO THE ISSUE OF BLACK HILLS' INTENTIONS TO BUILD OR NOT BUILD THE SD SUN PROJECT?

A: Yes, I have.

Q: WHAT IS YOUR RESPONSE TO THOSE ALLEGATIONS?

A: I disagree wholeheartedly with the allegation that exploration of the potential for a Black Hills' owned and developed SD Sun solar project was somehow a facade or undertaken to frustrate the process of negotiated discussion with Fall River.[26] Black Hills believes that its decision to acquire the development rights to the project and avoid the QF PPA pricing was in the best interests of its customers and provided a potential opportunity to explore a subscription based renewable option for customers. As part of that exploration, it determined that, at this time, it could not proceed because of the challenge of economically developing the project when compared to Black Hills' current and future costs to serve its system load.

Q: ARE YOU AWARE THAT FALL RIVER HAS ALSO MADE ALLEGATIONS ABOUT THE HANDLING OF THE SD SUN AVOIDED COST AND PPA NEGOTIATIONS, PARTICULARY WITH REGARD TO SD SUN I?

A: Yes, I am aware of Mr. Vrba's testimony.

Q: ARE THESE ALLEGATION RELEVANT TO THE MATTER CURRENTLY BEFORE THE COMMISISON?

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[26] *See* Direct Testimony of Ros Vrba at Page 12.

A: No, I do not believe they are at all relevant. As noted by Commission in F-3365, the Commission intends that, for contracts relating to QFs with a design criteria greater than 100kW, pricing and contracts should be negotiated between the parties, which is what occurred with SD Sun I and II. On behalf of the SD Sun I project, Mr. Vrba voluntarily entered into a PPA, after negotiations with Black Hills, and then subsequently sold the rights to that project and SD Sun II. Pricing and contract negotiations, which lead up to a negotiated arms-length transaction are simply extraneous to the matter before the Commission and distract from the actual issues, which appear to include: (1) continued viability of *Consolidated Edison*, (2) whether the modeling and price provided by Black Hills accurately reflects the costs it expects to avoid given current commodity forecasts, (3) the type of capacity that may be avoided and how to value that capacity.

Q: IF THE COMISSION WERE TO DETERMINE THAT THESE NEGOTIATIONS WERE RELEVANT, DO YOU AGREE WITH MR. VRBA'S CHARACTERIZATIONS OF THE NEGOTIATIONS?

A. No. I do not. I have reviewed communications dated April 8, 2015, June 3, 2015, June 16, 2015 and October 27, 2015 (see attached Exhibit KDW-5(a) – 5(g)), these reflect typical negotiations with questions raised by the QF developer, and, at times, adjustments and explanations provided by Black Hills. Indeed, at one point a retained consultant of Mr. Vrba explained that the Black Hills team was good to work with.

Q: HAVE YOU REVEIEWED TESTIMONY INDICATING THE FALL RIVER PROJECT IS WITHIN BLACK HILLS" EXCLUSIVE SOUTH DAKOTA SERVICE TERRITORY?

A: Yes, I have.

Q: IS THE FALL RIVER SOLAR PROJECT SITED WITHIN BLACK HILLS' EXCLUSIVE SERVICE TERRITORY?

A: No, it is not.

X. CONCLUSIONS

Q: WHO ULTIMATELY BEARS THE COST OF A POWER PURCHASE AGREEMENT WITH FALL RIVER, OR ANY OTHER QF?

A: Ultimately, all costs paid by Black Hills for a QF PPA are recovered from (paid for by) Black Hills' customers.

Q: DID CONGRESS OR FERC INCLUDE ANY PROTECTIONS TO ADDRESS THE REALITY THAT, IN THE END, COSTS OF A QF PPA ARE ULTIMATELY BORN BY THE UTILITY'S CUSTOMERS?

A: Yes. In its original legislation, Congress included a "customer indifference" protection.[27] In order, for the utility's customers to remain indifferent to the QF's energy or, stated similarly, to avoid discrimination toward the customer in favor of the QF, the appropriate focus must be on the costs that a utility can "actually avoid" by purchasing the QF output. Fall River's proposed methodology and derived avoided energy and capacity cost violate this key precept from PURPA.

Q: ARE THE QF'S COSTS MATERIAL TO DETERMING THE UTILITY'S AVODIED COST?

[27] *See* 16 U.S.C. §824a-3(b) explaining that rates for QF purchases "shall be just and reasonable to the electric consumers of the electric utility and in the public interest[.]"

A: No. The QF's costs are not material to determining a utility's avoided costs. Nothing in PURPA requires that a utility pay a rate that ensures a QF project is viable and can achieve financing, etc.

Q: ARE THERE ANY OTHER ISSUES WHICH COULD BECOME RELEVANT TO THE CASE BUT ARE NOT ADDRESSED IN THIS RESPONSE TESTIMONY?

A: Potentially, yes.

Q: PLEASE EXPLAIN YOUR ANSWER.

A: In prior avoided cost disputes, issues such as inclusion of carbon costs, compensation for renewable energy credits (RECs), cost of regulation, and appropriate deductions from the base avoided costs for interconnection costs have been at issue. At this point, it does not appear that Fall River is urging for inclusion of avoided carbon costs or REC compensation (which concepts the Commission has previously rejected). For this reason, Black Hills has not addressed these issues in its testimony. In addition, because the Parties never reached a point of discussing contract terms, issues such regulation costs and interconnection costs have not been a topic of significant discussion at this point. Likewise, it is my understanding that Fall River's project is still in the midst of the interconnection study process; thus some of the issues which arose in the *Consolidated Edison* case with regard to interconnection costs are not yet ripe. In this regard, Fall River recently contacted Black Hills and asked for an extension to provide its study deposit for its Facilities Study. Finally, in his testimony Mr. Vrba indicated that, though his current commercial operation date is in 2020, he may be seeking to extend that date into 2021 in light of current proceedings; this could impact the modeling already completed.

Q: IN LIGHT OF THE FOREGOING AND ANY OTHER ISSUES PREVIOUSLY DISCUSSED IN YOUR TESTIONY, DO YOU EXPECT TO SUPPLEMENT OR AMEND THIS DIRECT TESTIMONY.

A: Given these pending issues and indications in Fall River's testimony that it will likely be supplementing its testimony and might again change its methodology, I think it is likely that I will need to provide supplemental information. As noted herein, Black Hills has also committed that it will provide updated information in relation to the inflation of commodity prices and adjustment of the discount factor. For these reasons, I reserve the right to supplement, amend and/or modify this testimony.

Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A: Yes, it does.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE COMPLAINT OF ENERGY OF UTAH, LLC AND FALL RIVER SOLAR, LLC AGAINST BLACK HILLS POWER INC. DBA BLACK HILLS ENERGY FOR DETERMINATION OF AVOIDED COSTS

EL18-038

STATE OF SOUTH DAKOTA)
)SS
COUNTY OF PENNINGTON)

I, Kyle D. White, being first duly sworn, on oath state that I am Vice President - Regulatory Strategy for Black Hills Service Company, LLC, which is a wholly-owned subsidiary of Black Hills Corporation and an affiliate of the Respondent, Black Hills Power, Inc. d/b/a Black Hills Energy, in this proceeding, whose Direct Testimony and Exhibits were prepared by me or under my supervision. I am providing this testimony on behalf of Black Hills Power, Inc., and certify that the contents of the enclosed Direct Testimony and Exhibits are true and correct to the best of my knowledge, information, and belief.

Kyle D. White

Kyle D. White

Subscribed and sworn to before me this 7th day of May, 2019.

Notary Public
My Commission Expires December 19, 2019

KYLIE GRIFFITH
NOTARY
SEAL
PUBLIC
STATE OF SOUTH DAKOTA