EXHIBIT 10
Supplemental Testimony
IVAN VANCAS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

In the Matter of the Application of Black Hills Power, Inc.

To Approve Tariff Revisions Related to Its Cost of Service
Gas Agreement with Black Hills Utility Holdings, Inc.

Docket No. EL 15-036

June 24, 2016

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ivan Vancas and my business address is 625 9th Street, Rapid City, South Dakota 57701.

Q. ARE YOU THE SAME IVAN VANCAS WHO PREVIOUSLY PROVIDED DIRECT TESTIMONY IN THIS MATTER?

A. Yes.

Q. FOR WHOM ARE YOU TESTIFYING?

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

II. PURPOSE OF MY SUPPLEMENTAL TESTIMONY

Q. WHY ARE YOU PROVIDING SUPPLEMENTAL TESTIMONY?

A. Since filing the Application in this proceeding, the Company and Black Hills have participated in meetings and telephone discussions with consumer advocates and intervenors in various states where Black Hills has filed applications for approval of the COSG Program. In addition, Black Hills has received and had the opportunity to review testimony filed by intervenors in pending proceedings concerning the COSG Program. From those meetings, those discussions, and that testimony, some common issues have emerged that the Company believes warrant further response.

III. SUPPLEMENTAL TESTIMONY

Q. DO YOU HAVE ADDITIONAL TESTIMONY TO SUPPORT THE PURPOSES FOR THE COMPANY'S APPLICATION?

A. Yes. The Company takes its obligation to provide power to its customers at reasonable rates very seriously. The COSG Program, as proposed, is the product of years of investigation, review, and discussions, and is carefully structured to balance the interests of shareholders, who would provide all the capital, and customers. The Company believes that this proposal will benefit customers by protecting up to 50% of the gas supply used to generate power for customer from the volatility of market prices and the likely increase in market prices over the long-term.

In the 2005-2006 timeframe, I participated in a customer/industry forum facilitated by the Iowa Utilities Association. In that meeting, utilities were asked by customers why we did not "lock-in" gas prices on a long-term basis when they were lower than the then-current forecast of over $9.00 per dekatherm. Some customers said that "locking-in" was the utility's job and some suggested that we were "asleep at the wheel." That conversation has remained with me and continues to remind me of the Company's obligation to take the actions, to the extent possible, to minimize price volatility. That is why the Company has pursued the COSG Program, which is under consideration in this matter.

Q. PLEASE CONTINUE.

A. Having carefully reviewed the direct testimony submitted in other proceedings where Black Hills has applied for approval of the COSG Program, and having participated in a number of meetings and conference calls with intervenors to discuss the COSG Program, I have noted certain common concerns that have been raised. Those concerns generally relate to the following aspects of the proposed COSG Program: (i) the request to hedge up to 50% of the Company's weather-normalized annual firm demand; (ii) whether the 100-basis point deadband sufficiently balances risks between shareholders and customers; (iii) the mechanism for calculating Allowed ROE; (iv) the 60/40 equity to debt ratio; (v) the components of the Long-Term Market Price Forecast for Gas in the COSG Agreement;

(vi) the risk that drilling and operating costs might increase; (vii) whether 60 days is a sufficient period of time for the Commission and stakeholders to review proposed acquisitions and Drilling Plans; and (viii) intervenors' concern about their ability to timely retain outside support in connection with reviews of acquisition and Drilling Plans. Black Hills believes these concerns lack support and, in some cases, arise out of a misunderstanding of the COSG Program. The Company's Application in this Phase I proceeding, for authorization of the framework, should be approved, after which BHUH will work to implement the COSG Program, subject to Commission review and approval in a Phase II proceeding, so that customers can realize the benefits of a long-term physical hedge.

That being said, because the Company strongly believes that a long-term physical hedge is in customers' best interests, it would not object if the Commission, in its approval of Phase I, required a few adjustments to the COSG Program to address certain concerns raised by intervenors. For example, in its report to BHUH, Aether Advisors recommended that the Company hedge a minimum of 35% of the Company's gas supply through a long-term physical hedge, with a goal of increasing that percentage to 50%.[1] The COSG Agreement provides for hedging up to 50% of the Company's current gas supply needs through the COSG Program. However, Black Hills would not object if the Commission were to decide in this Phase I proceeding that a lower percentage, even down to 35%, is appropriate.

Q. IS THE COMPANY PROPOSING THAT LESS THAN 50% OF ITS CURRENT GAS SUPPLY NEEDS BE HEDGED THROUGH THE COSG PROGRAM?

[1] Ryan Direct Testimony, Exhibit 5, Page 36, Lines 18-20.

A. No. The Company continues to believe that 50% should be approved based on its analysis of the reserve prices, market conditions and the benefits of the COSG Program. However, in light of the stakeholders' concerns, particularly as they relate to the early years of the COSG Program, the Company would not object if the Commission were to decide that between 35% and 50% of the Company's weather-normalized annual firm demand should be hedged under the COSG Program.

Q. PLEASE CONTINUE.

A. With regard to the question of risk-sharing under the COSG Program, because the Company strongly believes that a long-term physical hedge is in customers' best interest and that customers will save money under the COSG Program over its term, the Company would also not object if the Commission decided that the Company should assume additional risk and doubled the 100-basis point deadband to 200 basis points on either side of the Allowed ROE. Although this would decrease the risk of customers bearing Hedge Costs, in practice, and because gas prices are more likely to increase than decrease, it will more likely decrease the Hedge Credits that customers receive. For that reason, the Company is not recommending this change. However, if the Commission were to decide that such a change is in customers' best interest, the Company would not object.

Similarly, the Company believes that the mechanism for calculating the Allowed ROE in the COSG Agreement is appropriate. However, the Company would not object if the Commission determines that only the average of gas utility rate cases reported by Regulatory Research Associates (rather than the average of gas utility ***and*** electric rate cases) should be used to calculate the Allowed ROE under the COSG Program.

In addition, concerning the capital structure of the COSG Program, some intervenors have suggested that the proposed capital structure (60% equity/40% debt) should be closer to a 50/50 capital structure. The Company continues to believe (and evidence continues to support) that the Company's proposed structure is appropriate and justified. However, if the Commission decides that a 50/50 capital structure should be used rather than the proposed 60/40 structure, the Company would not object.

Q. YOU ALSO MENTIONED THE FORECASTS INCORPORATED INTO THE LONG-TERM MARKET PRICE FORECAST FOR GAS. PLEASE EXPLAIN.

A. Long-term resource decisions should be made using long-term price forecast information. Although some intervenors have suggested that NYMEX Futures Contracts are a better indicator of future spot market prices, NYMEX Futures Contracts do not offer good visibility of the direction of long-term market prices due to lack of trades beyond a few years.[2] For that reason, the Company does not believe that substituting NYMEX Futures Contracts for the Long-Term Market Price Forecasts for Gas under the COSG Program would be beneficial. However, because the Company believes the consideration of NYMEX Futures Contracts provide an element of current market perspective, the Company would not object if NYMEX Futures Contracts were averaged into the Long-Term Market Price Forecast for Gas under the COSG Agreement in the following way: (i) for each of the first five years of a given Long-Term Market Price Forecast for Gas, the average of the then most recent NYMEX Futures Contracts, long-term [redacted] base case, and long-term EIA reference case would be used; and (ii) the remainder of the Long-Term Market Price Forecast for Gas for years 6-20 would consist of the average of the then most

[2] Aether Report, Exhibit 5.1, Pages 50-53.

recent long-term [redacted] base case and long-term EIA reference case, as presently proposed.

Q. WHAT ABOUT THE RISK THAT DRILLING AND OPERATING COSTS MIGHT INCREASE ABOVE WHAT IS ANTICIPATED?

A. As described in Mr. Benton's direct testimony, within fields containing significant proven reserves, which the Acquisition Criteria of the COSG Program requires, drilling and operating costs are relatively predictable and stable.[3] However, assuming the Commission adopted a 200-basis point deadband, Black Hills would not be opposed to the Commission requiring in Phase II that BHUH consider mechanisms that would further minimize risks associated with these costs for customers' benefit. For example, BHUH would be amenable, for purposes of calculating Hedge Credits and Hedge Costs during the first three years of the first Drilling Plan, to proposing a cap on aggregate drilling costs to an average $/foot to be determined in the Phase II proceeding for that first property with typical industry adjustments such as fuel-related costs. In that situation, Black Hills shareholders (rather than customers) would take on 100% of the risk that actual drilling costs exceed the agreed-to cap. In addition, the Company would not object to a limitation requiring that corporate general and administrative costs for that Drilling Plan be fixed in the Phase II proceeding with an inflation escalator. Furthermore, to address intervenors' concerns, the Company would not object to the Commission requiring three-year Drilling Plans rather than the proposed five-year Drilling Plans, although the Company notes that it continues to believe five-year Drilling Plans are more appropriate and would better maximize customer benefits under the COSG Program.

[3] Benton Direct Testimony, Exhibit 4, Page 11, Line 1 to Page 13, Line 1; *Id*., Page 26, Lines 14-16.

Q. WHAT ABOUT THE 60-DAY REVIEW PERIOD AND INTERVENORS' ABILITY TO TIMELY RETAIN OUTSIDE SUPPORT IN CONNECTION WITH THESE REVIEWS?

A. The Company continues to believe that these issues are appropriately addressed by the independent Hydrocarbon Monitor's role in the review process. Indeed, the 60-day timeframe has worked successfully for other cost-of-service gas programs. However, while recognizing that expanding this timeframe could result in certain reserve opportunities becoming unavailable to the COSG Program, the Company believes the following timeframes could allow some reserve opportunities to be pursued under the COSG Program: a 180-day review period for any proposed acquisition of a BHEP property, a 120-day review period for any proposed acquisition from an unrelated third-party (provided that the third-party has agreed to such an extended review period, [redacted]), and a 120-day review period for updated Drilling Plans. Furthermore, BHUH would be willing to establish an escrow-like fund containing $250,000 that statutory customer advocates in other states and the Staff of this South Dakota Public Utilities Commission ("Staff") could cooperatively utilize to timely retain or have on retainer additional outside support in connection with these reviews, to the extent they determine that such additional support is necessary beyond what is provided by the Hydrocarbon Monitor. If these costs were not reflected in Staff or customer advocates' budgets, the Company would expect that those costs would be recovered through the COSG Program.

Q. SOME INTERVENORS CLAIM THAT BLACK HILLS ALREADY MADE A DECISION TO PROPOSE INCLUDING ITS MANCOS SHALE ASSET IN THE COSG PROGRAM. IS THIS ASSERTION CORRECT?

A. No. As the Company has reiterated both in its direct testimony and in its responses to a substantial number of data requests, no final decision has yet been made on any reserve opportunity and, in fact, no such decision could be made before this Phase I proceeding has been approved. Only then will the Company know the scope, parameters, and guidelines of the COSG Program and be able to assess whether any potential reserve property satisfies the Acquisition Criteria or will satisfy the other requirements of the approved COSG Program. It is true that, in discussions with analysts, Black Hills management has discussed that the BHEP Mancos assets may be a good fit for the COSG Program but only if those assets satisfy both the customers' and Black Hills' needs. Before any BHEP assets could be seriously considered, the parameters, requirements, and economics of any such transaction would have to be determined under the COSG Program Acquisition Criteria as approved. In this regard, Black Hills believes its Mancos Shale asset in the Colorado Piceance Basin is a world-class asset that is ideally suited to generate customer benefits under the COSG Program. However, Black Hills is also mindful that the Acquisition Criteria in the COSG Agreement require that any sale from BHEP to COSGCO would have to be "fair based on other deals with unrelated third parties that are known in the market."[4] The E&P industry is experiencing a profound disruption due to the current, unsustainably low-price environment. This is causing many E&P companies severe financial distress, and distressed companies are selling producing gas assets for

[4] COSG Agreement, Exhibit 3.1, Exhibit A.

prices below the development cost of those assets. This circumstance may create a great opportunity for COSGCO to purchase gas reserves from distressed third-party sellers who are willing to sell properties at prices lower than what BHEP would be willing to sell its Mancos asset. The Company's witness Mr. White addresses the Company's anticipated plans for pursuing producing assets and related proven reserves at an effective cost of service gas price of approximately [redacted]/dekatherm or better (based on market conditions for natural gas in the recent past) for implementing the COSG Program in a Phase II application.

VI. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

AFFIDAVIT

STATE OF SOUTH DAKOTA)
)
COUNTY OF PENNINGTON)

I, Ivan Vancas, being first duly sworn on oath, do hereby depose and state:

1. I am employed by Black Hills Utility Holdings as Group Vice President of Natural Gas Utilities, and my business address is 625 9th Street, Rapid City, South Dakota 57701.

2. I have prepared written supplemental testimony and caused my written supplemental testimony to be filed with the South Dakota Public Utilities Commission in Docket No. EL15-036 on June 24, 2016.

3. I hereby affirm that my written supplemental testimony is true and correct to the best of my knowledge and belief as of the date of this affidavit.

Done at Rapid City, South Dakota, on June 23rd, 2016.

Ivan Vancas
Group Vice President of Natural Gas Utilities

Subscribed and sworn to before me on June 23rd, 2016.

CAROLYN J. SCHELER
NOTARY PUBLIC
SOUTH DAKOTA

Notary Public in and for said County and State
Commission # ____________
My commission expires 1-10-2021