BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NEBRASKA

IN THE MATTER OF BLACK HILLS/NEBRASKA GAS UTILITY COMPANY, LLC, d/b/a BLACK HILLS ENERGY, OMAHA, SEEKING APPROVAL OF ITS COST OF SERVICE HEDGE AGREEMENT WITH BLACK HILLS UTILITY HOLDINGS, INC.	)))))	APPLICATION NO. NG-0086

PUBLIC VERSION

DIRECT TESTIMONY AND EXHIBITS OF

MICHAEL J. MCGARRY SR

ON BEHALF OF THE NEBRASKA PUBLIC ADVOCATE

FEBRUARY 16, 2016

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I. Introduction

A. Witness Identification and Testimony Overview

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Michael J. McGarry Sr. I am employed as President and Chief Executive Officer by Blue Ridge Consulting Services, Inc. My business mailing address is 2131 Woodruff Rd. STE 2100 PMB 309 Greenville, South Carolina 29607.

Since July 2004, I have been President of Blue Ridge Consulting Services, Inc. I have participated in and/or overseen numerous rate cases and related audits, power supply cost recovery proceedings, management and operational audits, and prudence proceedings. I have worked with clients to manage various aspects of the regulatory and rate case process, prepared supporting analyses and testimony for submission to regulatory bodies and interveners, prepared revenue requirement and cost of service analyses, and developed complex revenue requirement models to present alternative positions to a utility's proposed rate request. Prior to assuming my present position, I was Vice President of East Coast Operations from July 2003 to June 2004 with Hawks, Giffels & Pullin, Inc. (HGP). In that position, I was responsible for developing and overseeing client engagements in utility regulatory affairs, management audits, and rate case management.

From August 2001 to July 2003, I was an independent consultant working on a number of different projects, including a renewal/update of delivery service tariffs for Illinois Power Company (now, Ameren Illinois) and several utility street-lighting cost-benefit-assessment projects.

From June 2000 until August 2001, I was a senior consultant with Denali Consulting, Inc., a utility supply chain and e-procurement strategy and implementation firm.

From October 1997 through June 2000, I was employed by Navigant Consulting, Inc., and several of its predecessors or acquired firms working on a number of different projects, including a management audit of Southern Connecticut Gas Company and the original delivery service tariff filing for Illinois Power.

From July 1985 through October 1997, I was employed by the New York State Department of Public Service (NYSDPS) in its Utility Operational Audit Section where I conducted focused operational audits in many facets of utility operations for all sectors of the utility industry including electric, gas, telecommunications, and water.

Prior to my employment with the NYSDPS, I was a rate analyst with Orange and Rockland Utilities (1981 to 1983) and then Seminole Electric Cooperative (1983 to 1985).

I received my Masters of Business Administration from the State University of New York at Buffalo in 1996 and a Bachelor of Arts in Economics from Potsdam College (SUNY) in 1981.

Q. WHAT OTHER INDUSTRY EXPERIENCE DO YOU HAVE?

A. I have presented topics before staff groups, including regulatory commissions, NARUC sub-committee groups, and as a program faculty member for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, and price regulation theory.

Q. HAVE YOU INCLUDED A MORE DETAILED DESCRIPTION OF YOUR QUALIFICATIONS?

A. Yes. My resume is included as Appendix A.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Nebraska Public Advocate.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEBRASKA CORPORATION COMMISSION?

A. No.

Q. IN WHAT OTHER JURISDICTIONS HAVE YOU PREVIOUSLY APPEARED AS A WITNESS OR FILED TESTIMONY?

A. I have testified in Arizona, Delaware, Georgia, Illinois, Maine, Maryland, Michigan, Missouri, New York, North Dakota, Nova Scotia, Ohio, and Utah. These proceedings included testimony involving rate case evaluations, power supply cost recovery, management decisions and prudence impacts, operations and maintenance expenses, capital investments, revenue requirements, project management, and other areas. More recently, I have testified for the Arkansas Attorney General as a revenue requirements and cost of service witness in Docket No. 15-015-U, Entergy Arkansas's request for an increase in base rates.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony includes my evaluation of the Applicants' request that the Commission (1) authorize the Applicant, Black Hills/Nebraska Gas Utility, LLC, d/b/a Black Hills Energy ("Black Hills NE" or "Company") to enter into a cost-of-service gas hedge agreement ("the COSG Agreement") with Black Hills Utility Holdings, Inc. ("BHUH"), (2) approve the related Purchase Gas and Annual Cost Adjustment tariffs, (3) approve the requested 50% hedge-participation level of the Company's forecasted annual demand (or a revised amount that the Commission determines, and (4) grant any necessary waivers from the Commission's affiliate rules or regulations or any ring-fencing commitments that the Commission deems applicable.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. After careful review of various components of how this cost-of-service agreement would work and impact Black Hills/NE ratepayers, I conclude that this cost-of-service hedging agreement for up to 50% of Black Hills/Nebraska's firm natural gas annual demand would not be in the public interest and should be rejected. Specifically, I base my conclusion on the following factors:

1. The Company's proposal unduly shifts the risk of excessive costs and inappropriately guarantees cost recovery of an unregulated affiliate's investment and operating costs through the hedge true-up.
2. The Company's request—to establish the return of investment for the investments in the development of the reserves that would be the subject of the COSG Program based on the average rate of return of all electric and gas utilities set in the prior year— is unreasonable and could lead to Black Hills/NE ratepayers providing a higher return than they currently pay to the Company
3. Similarly, the requested debt/equity ratio of 40/60 will overstate the return to the unregulated affiliate COSGCO.[1]
4. The 60-day review period proposed under the Company's cost-of-service gas proposal is too short to provide adequate review considering the volume of data and the cost implications.
5. The Company's brief review period also applies to forecasts, unduly shifting risk to ratepayers that traditionally and naturally should be borne by the Company.
6. The Company's plan to use a Hydrocarbon Monitor and an Accounting Monitor who would be hired and paid for by the Company, with only

[1] COSGCO refers to the as-yet theoretical unregulated affiliate that will be created under Black Hills Utility Holdings to acquire and/or develop existing/new natural gas reserves.

approval by the Commission, is an inadequate independent safeguard to provide the necessary expert evaluation for the Commission and intervenors.

7. The hypothetical/illustrative example provided in Company Exhibit AC-2 combined with the sensitivity of that analysis to any changes in the underlying assumptions (e.g., price forecasts), makes it virtually impossible to know when, and even if, customers will start to see benefits from the COSG program.
8. If one or more commissions/utility boards of BHUH Utilities do not approve the similar COSG program in their respective jurisdictions, the remaining operating companies will be left to shoulder the burden of the costs that would have been allocated to and paid for by the other operating company(ies) not receiving approval for the COSG program.
9. The Termination Clause of the COSG Agreement may usurp the Commission's ability to ensure just and reasonable rates for Black Hills/NE customers.
10. With respect to the Purchase Gas and Annual Cost Adjustment tariffs, since I am not recommending the approval of the Company's Cost-of-Service Gas Agreement and Plan, the question of the tariffs is moot.
11. With respect to the 50% hedge-participation level of the Company's forecasted annual demand, since I am not recommending the approval

of the Company's Cost-of-Service Gas Agreement and Plan, the question of the hedge proposal is also moot, and I recommend maintaining the current hedging levels that have been approved previously by the Commission.

12. With respect to granting any necessary waivers from the Commission's affiliate rules or regulations or any ring-fencing commitments that the Commission deems applicable, since I am not recommending the approval of the Company's Cost-of-Service Gas Agreement and Plan, the question of the waivers becomes unnecessary.

Q. ARE YOU PRESENTING ANY EXHIBITS IN CONNECTION WITH YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. Exhibits MJM-1 through MJM-8 support my analysis and the resulting testimony:

Exhibit MJM-1 - Response to Wyoming Staff Data Request CIR 3.6

Exhibit MJM-2 – Exhibit IV to Black Hills/Nebraka Witness Ivan Vancas, proposed Cost of Service Gas Agreement

Exhibit MJM -3 – Black Hills/NE response to Public Advocate Data Request PA-33

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B. Background

Q. PLEASE PROVIDE THE BACKGROUND ON THE BLACK HILLS/NE APPLICATION.

A. Black Hills/NE provides natural gas service to approximately 200,000 residential, commercial and industrial customers servicing 106 communities in the eastern third of Nebraska.[2] In 2014, Black Hills/Nebraska had purchased gas expense of $108.9 million dollars and delivered 17,835,438 Mcf of natural gas to customers.[3] On September 30, 2015, Black Hills/NE filed with the Commission an application for approval of a cost-of-service purchase agreement and related issues wherein an unregulated affiliate, hereinafter referred to as "COSGCO" (cost of service gas company), would acquire and develop yet-to-be-determined gas reserves. Gas produced from these reserves would be sold to the open market, and the resulting net costs or credits would be charged back to Black Hills/NE ratepayers through the cost-of-service agreement and the Company's PGA. This filing comes after several months of preliminary information and discussion sessions among the Company, Staff, and interested stakeholders, including the Public

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[2] Application, page 2.
[3] FERC Form 2 pages 321 and 301b, respectively.

Advocate. A planning conference was held on November 16, 2015, and a procedural order was issued on November 20, 2015.

The Companies' Application is made pursuant to Neb. Rev Stat §§ 66-1808 (Rate changes; term or condition of service; when effective), 66-1854 (Cost of gas supply; effect on rate schedules; procedure), and other applicable statutes of the State Natural Gas Regulation Act and orders issued by the Commission.

II. Summary of Proposed Cost-of-Service Gas Program

A. Overview of Proposed Cost-of-Service Gas Program

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S PROPOSED COST-OF-SERVICE AGREEMENT.

A. As proffered by Company Witness Ivan Vancas, Black Hills/Nebraska is requesting approval of an agreement between the Company and Black Hills Utility Holdings (BHUH) that will create a cost-of-service gas (COSG) program. This program will purportedly create a long-term hedging program, whose purpose, Witness Vancas states, is to "reduce the Company's customers' exposure to the volatility of gas prices, to provide long-term price stability through a physical hedge, and to provide an opportunity for customers to pay less than market prices over the long term."[4] He states that a physical hedge would be created through the acquisition of natural gas

[4] Direct Testimony of Ivan Vancas, page 4, lines 13-16.

wells that are or could produce natural gas at production costs, "which, over the life of the wells and on a net present value basis, are anticipated to be below forecast market prices."[5] He claims that the COSG Program would "effectively peg a portion of customers' gas costs to today's low gas prices and to stable and predictable production costs during the term of the COSG Agreement."[6] It is important to note that Black Hills/Nebraska would not purchase natural gas directly from these acquired reserves; rather, the gas would be sold into the natural gas market at market rates. BHUH would purchase natural gas on the market and either charge or credit customers for any difference between the cost-of-service price as determined by the COSG agreement and the market price that the acquired (or developed) reserves generate in the open market. The Company states that maintaining this arms-length approach preserves certain tax benefits that the COSGCO can take advantage of and thus lower costs to customers.

Mr. Vancas lists the specific components of the Company request. They include the overall determination that the COSG Program and the related COSG Agreement are prudent and that the amounts associated with the COSG Program are eligible for recovery through the Company Purchase Gas Adjustment Clause (PGA). The request includes four major components:

1. Authorize the Company to enter into the COSG Agreement, which incorporates these items:

[5] Direct testimony of Ivan Vancas, page 4, lines 18-20.
[6] Ibid. lines 20-22.

(a) Acquisition and drilling criteria

(b) An expedited process for Commission review of acquisition opportunities

(c) Other guidelines to protect the Company's customers; the guidelines include these customer protections:

(i) Commission review of all proposed drilling plans every five years

(ii) The retention by BHUH of a mutually acceptable hydrocarbon monitor ("Hydrocarbon Monitor") that would review potential acquisitions and drilling plans

(iii) The retention by BHUH of a mutually acceptable accounting monitor ("Accounting Monitor") that would assess the financial information of the COSG Program, as provided in the COSG Agreement, and provide an assurance report

2. Approve the revised tariff sheets that incorporate the "Hedge Credits" and "Hedge Costs" under the COSG Program

3. Approve the requested 50% hedge-participation level based on the Company's forecast annual firm demand or, in the alternative, a revised percentage that the Commission may determine

4. To the extent necessary, grant any waivers from affiliate rules, regulations, or ring-fencing commitments, the Commission deems necessary.

B. Pre-determination of Prudence

Q. DOES THE COMPANY STATE THE REASON IT NEEDS A PRUDENCE DETERMINATION BEFORE ENTERING INTO THIS AGREEMENT?

A. Yes. Company Witness Vancas provides four reasons for the pre-determination of prudence of this agreement:[7]

1. Determination is required by Nebraska Revenue Statute § 66-1854.[8]
2. Prudence determination is "advisable in light of ring-fencing protections that were put in place when BHUH acquired certain utilities that could be involved in the COSG program.
3. While the Company already purchases gas from BHUH, the COSG Program is the first time the Company would be a participant in a program in which long-term gas reserves are acquired. Since the investment in these reserves will be significant, it will require coordination with utilities in several states. Witness Vancas states that "the Company believes it is appropriate to seek a prudence determination from this Commission, as well as the public utility

[7] Direct Testimony of Ivan Vancas, page 6.
[8] Statute 66-1654 Cost of gas supply; effect on rate schedules; procedure.

commissions in each state where the COSG Program would be in effect before undertaking the COSG Program."[9]

4. The Company insists that the nature of gas reserve acquisitions necessitates both pre-approval of the Commission oversight process and the acquisition guidelines that are incorporated into the COSG Agreement. Witness Vancas argues that this is true "because the closing timelines of typical sellers of oil and gas interests are shorter than typical Commission review processes, and the COSG Program will likely find willing sellers who will want some comfort that the Commission will likely approve a proposed transaction." He further states that "the proposed Commission oversight process and guidelines address these issues, while also appropriately protecting the Company's customers."[10]

C. Multi-Jurisdictional Approval

Q. DOES THE COMPANY'S PROPOSAL REQUIRE APPROVAL IN OTHER JURISDICTIONS?

A. Not necessarily. To my knowledge, the Company's regulated affiliate utility companies in five (5) other jurisdictions have made similar filings to the one here in NG-0086 in each of their respective jurisdictions, including Colorado, Iowa, Kansas, Wyoming, and South Dakota. Each of the filings is in various stages of review. At the time of the filing of this testimony, none has given

[9] Direct Testimony of Ivan Vancas, page 6, lines 11-14.
[10] Direct Testimony of Ivan Vancas, page 6, lines 14-21.

approval for the COSG program. However, the Company has said that, based on the economics and operating considerations, it could move forward even if a commission did not approve its proposal, depending on the level of committed firm demand of natural gas to the COSG Program in the other jurisdictions.[11]

III. Public Advocates Review Of The Components Of The Cost-Of-Service Program

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. In this section, I will review the major component of Black Hills/NE's proposal: the authorization of the Cost-of-Service Gas Agreement and Plan. The other issues of the Company's proposal hinge on the authorization of the Cost-of-Service Gas Agreement and Plan. Unless this item is found with merit, the other elements of the Company's proposal are moot.

Q. WHAT ARE YOUR CONCERNS WITH THE COMPANY'S PROPOSED COST-OF-SERVICE GAS AGREEMENT/PROPOSAL?

A. I believe that the COSG Program, as proposed by the Company is an unworkable, risky venture that could be detrimental to ratepayers and is not in the public interest. Too many moving parts (both known and unknown)

[11] Exhibit (MJM-1) Response to Wyoming Staff Data Request CIR Data Request 3.6 filed in WYPSC Dockets 20003-145-EA-15; 30005-208-GA-15; 30011-92-GA-15; and 20002-98-EA-15 (Record No. 14241), In this response, the Company states, "Once BHUH knows the actual portfolio percentage commitments from the multiple states in which Black Hills Utilities have applied, then it will reevaluate the feasibility of continuing the COSG Program. There has to be a level of size and scale to the aggregate program to ensure that the administrative and other costs to maintain the program are not overly burdensome to the cost of producing gas."

have to come together and stay together in order for the program to benefit the Company's customers and not unduly burden them with otherwise absent risk and costs. The following significant issues make the Company's proposal regarding the predetermination of the COSG Program Agreement unworkable and not the public interest.

- Risk Shifting
- Requested Rate of Return
  - Debt Structure
- Review and approval of the acquisition and drilling plan
  - Expedited review by monitors/Five Year Plan
  - Commission/Advocate ability to review
- Modeling, Forecast Assumptions and Hypothetical basis of approval
- Impact of disapproval by one or more other Commissions
- Termination Clause

I will address each of these in order.

A. Risk Shifting

Q. PLEASE DECRIBE YOUR CONCERNS WITH RISK FOR THE COMPANY'S NEBRASKA RATEPAYERS?

A. As proposed in the COSG Agreement, all COSG Program costs will be trued up every year through the hedge cost/credit provisions of the agreement.[12] This includes production, operations, and maintenance costs, along with the return on the investment on the production facilities. Therefore, the ratepayers will absorb any and all fluctuations in costs of this program.

[12] Exhibit MJM-2: Cost of Service Gas Agreement (as included as Exhibit IV of Ivan Vancas Direct Testimony – See Section 5.3 Annual Hedge Reconciliation).

Further, the hedge amount will be based on a forecast, and thus true-ups will be automatic.

Q. WHY IS THIS A CONCERN?

A. The proposed scheme creates undue burden along two fronts. First, it mandates that the Commission and the intervening parties have only a very expedited, and thus brief, period (no more than 60 days) to review the costs and make a determination and recommendation of their reasonableness. Second, it shifts risk to ratepayers. The brief review also applies to the subsequent forecasts. In a traditional rate regulation plan, the utility is not provided a guarantee of recovery of costs or its return; it is provided only the opportunity to earn its approved return. Under the current proposal, in which cost recovery and return is actually guaranteed, the risk of non-recovery shifts away from the parent company shareholders to rest squarely on the ratepayers.

Q. DOES THE COMPANY PROPOSE TO ABSORB ANY RISK ASSOCIATED WITH THIS PROGRAM?

A. They do, but only to the extent that the return on equity is within 100 basis points below the approved return. Any burden beyond that is borne by the ratepayers. In other words, if excessive drilling, operations, and maintenance costs adversely impact the COSGCO's ROE beyond 100 basis points, the ratepayers must make up the difference. Likewise, if drilling and production do go well, and COSGCO returns are above the allowed ROE, the Company keeps the first 100 basis points, and only excessive returns above that are returned to ratepayers in the form of a hedge credit. While this may be an incentive for COSGCO, it is a burdensome and therefore unreasonable risk for ratepayers.

Q. HOW WILL THE ROE BAND WORK?

A. If the Weighted Cost of Gas as calculated per the specific formula in the Agreement is less than COSGCO's price to market, BHUH retains that amount up to 100 basis points on the agreed-to ROE and credits customers with any remainder if in excess of 100. If the Weighted Cost of Gas is greater than COSGCO's price to market, BHUH absorbs the amount up to 100 basis points. The new hedge cost would include an amount for the excess.[13] As I have stated, in my opinion, this shifts too much of the potential adverse risk for the speculative venture into acquiring reserves, drilling, and production onto ratepayers. Even the Company's own witness acknowledges that acquisition, drilling, and operating costs could be higher than expected.[14]

B. Requested Rate of Return

Q. WHAT ARE YOUR CONCERNS WITH THE COMPANY'S PROPOSED METHODOLOGY FOR ESTABLISHING THE RETURN OF EQUITY FOR THE HEDGE COST?

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[13] Exhibit MJM-2: Cost of Service Gas Agreement (as included as Exhibit IV of Ivan Vancas Direct Testimony) – See Section 5.1 – Hedge Settlement.
[14] Direct testimony of John Benton, page 15, lines 4-13.

As stated by Company Witness McKensie,

> "The COSG Agreement specifies that the Allowed ROE will be the average of the annual return on equity in all gas and electric utility rate cases for each calendar year, as subsequently reported by Regulatory Research Associates ("RRA") in its Regulatory Focus report entitled, "Major Rate Case Decisions," provided that if less than twenty (20) gas and electric utility rate cases are reported for a calendar year, then the Allowed ROE for that calendar year shall equal the average of (i) the average of the annual return on equity in all gas and electric utility rate cases for that calendar year, and (ii) the average of the annual return on equity in all gas and electric utility rate cases for the prior calendar year, all as reported by Regulatory Research Associates."

Based on this statement, the rate of return for the investment costs associated with acquired reserves and related capital costs will be established on a rate that is not the Company's latest approved return on equity.

Q. DOES THE COMPANY OFFER AN ESTIMATE OF WHAT THIS RATE WILL BE FOR THE FIRST YEAR OF THE PROGRAM IF IT IS APPROVED BY THE COMMISSION?

A. Yes. Witness McKensie states that the rate allowed in the current COSG Agreement if approved would be 9.86%.[15]

Q. WHAT IS THE COMPANY'S CURRENT ALLOWED RATE OF RETURN?

A. As approved by the Commission in its most recent base rate case NG-0061 (Order approving application August 17, 2010), the Company's allowed rate of return is 9.111%.

Q. WHY IS GRANTING A HIGHER RATE FOR THIS TYPE OF BUSINESS VENTURE A PROBLEM?

A. Besides being a substantially higher (8% higher) rate, the Company is asking that its return be based, not on the relevant facts and circumstances for Black Hills/NE, but rather on an external source, which may have no connection to what the Commission would normally hold for the Company in its base rates. If the Commission decides to approve the COSG Program, whatever ratepayers are returning to shareholders should be the same as that which they pay for the infrastructure used to provide service to its customers (i.e., the Company's most recently approved rate of return).

Q. WHAT ARE YOUR CONCERNS WITH THE DEBT STRUCTURE?

A. In this issue, the Company's proposal is even more troubling than with the rate of return. The Company is seeking to include a debt structure of 40/60 debt to equity. This ratio must be compared to the Company's current ratio of

[15] Direct Testimony of Adiren McKensie, page 18, line 15.

48/52 as approved in NG-0061. What this difference means is that overall weighted return will be higher simply because of the change in the ratio since debt costs are less (cheaper) than the ROI. The Company's approved long-term debt cost is 8.04%.

Q. DOESN'T THE COMPANY PROVIDE AN EXTENSIVE ARGUMENT CONCERNING THE DEBT STRUCTURE AND RETURN INVESTORS IN THIS TYPE VENTURE REQUIRE?

A. Yes. Witness McKensie provides a detailed discussion on both issues. However, Witness McKensie downplays or ignores altogether that the funds that will be used to support this venture are ratepayer funds and a guaranteed revenue stream regardless of what happens to the costs of production and operations. Under the proposed COSG Agreement, Black Hills/NE's ability to recover all production and operations costs and guarantee the return on investment means that the COSGCO's business and operational risk has to be lower than even the Company's, and certainly that risk would also have to be much lower than normal exploration and drilling companies that do not have a guaranteed revenue stream. Like the return on investment, the debt structure should follow the same process of evaluation and be based on actual empirical data based on the Company's (i.e., Black Hills/NE's) debt-to-equity ratio.

C. Review and approval of the Acquisition and Drilling Plan

Q. PLEASE EXPLAIN YOUR CONCERNS WITH REVIEW AND APPROVAL OF THE ACQUISITION AND DRILLING PLAN?

A. The Company is proposing that the Commission and interested stakeholders, including the Nebraska Public Advocate would have an opportunity to review a five-year reserve acquisition and drilling plan (Drilling Plan). The specifics of this review are included in Section 4.4 of the proposed COSG Agreement. This plan would be filed with the Commission 60 days prior to the end of the five-year anniversary of the then current plan. The five-year drilling plan will include the following information:

- Data and information described in Section 4.2(iii)-(xiv) of the COSG agreement for each Property:

  (iii) Gross working interest and net revenue interest to be acquired or earned by COSGCO in existing wells, if any, and wells to be developed through execution of the Proposed Drilling Program;

  (iv) Historical production from and remaining reserves of existing wells;

  (v) Forecast reserves for wells to be developed through execution of the Proposed Drilling Program;

  (vi) Forecast production for existing wells and wells to be developed through execution of the Proposed Drilling Program, showing aggregate production per year;

(vii) A summary of geologic and geophysical data;

(viii) Historical exploration, drilling and operating costs (including gathering and processing costs) of existing wells;

(ix) Forecast operating costs (including gathering and processing costs) of existing wells;

(x) Forecast capital and operating costs (including gathering and processing costs) for future wells;

(xi) Estimated production tax for existing wells and to be developed through execution of the Proposed Drilling Program;

(xii) A third-party engineering report (the "**Reserve Report**") assessing, using the then-current Long-Term Market Price Forecast, (1) the proved reserves (including without limitation proved undeveloped reserves) and any probable reserves to be developed through execution of the Proposed Drilling Program, (2) the forecast production for existing wells and wells to be developed through execution of the Proposed Drilling Program, and (3) the estimated cost to develop the proved reserves through execution of the Proposed Drilling Program and the projected costs per Dth for existing and to-be-developed reserves as produced;

(xiii) Then-current Long-Term Market Price Forecast;

(xiv) The "**COSG Cost Forecast**," which means, for each year of the Reserve Report, the forecast Gas cost calculated in nominal dollars pursuant to the following formula:

*COSG Cost Forecast = [COSGCO OpEx + (Cost of Capital * Investment Base)] - Liquids Revenue Provided* that (i) "Liquids Revenue" means the money COSGCO is anticipated to receive from the sale of all Hydrocarbons other than Gas, and (ii) the then-current Long-Term Market Price Forecast and the Proposed Drilling Program, Drilling Plan or Drilling Plan II, as applicable, shall be used in calculating the COSG Cost Forecast;

- Black Hills/Nebraska's aggregate Hedge Target for each remaining year in the twenty (20) year period following the First Acquisition Date, and
- An updated Drilling Plan for each Property for such period.

1. <u>Expedited Review by monitors/five year plan</u>

Q. THE PREVIOUS LIST APPEARS TO BE QUITE AN EXHAUSTIVE LIST OF DATA AND INFORMATION. WHY IS THIS NOT SUFFICIENT FOR THE COMMISSION AND THE PUBLIC ADVOCATE TO MAKE A DETERMINATION OF THE REASONABLENESS OF THE DRILLING PLAN?

A. It is not so much that the list would not be sufficient to conduct a thorough review of the proposed drilling plan. It is the expedited review and the required level of expertise that is required by the Commission and the interested stakeholders, including the Public Advocate to adequate conduct the review. For example, the COSG calls for an expedited review through the use of what the Company has termed a "Hydrocarbon Monitor," which the Company defines as "an independent third party with substantial experience evaluating oil and gas transactions."[16] Further, the Company would engage the services of an "Accounting Monitor" who would be an independent, third-party certified public accountant. These monitors would be hired by the Company but approved by the Commission to provide the technical engineering and accounting/financial oversight review of the Company's five-year drilling plan as well as the review of any additional properties acquired during the plan's time frame **and** the review of the accounting for the hedge costs(credits). As stated by Witness Vancas, "The Hydrocarbon Monitor would be an independent third party not affiliated in any way with the Company or BHUH and would

(i) assess any proposed acquisition or an initial drilling plan and provide a written recommendation regarding whether the proposed acquisition or drilling plan satisfies the criteria in the COSG Agreement;

(ii) assess every five years the future drilling plans and provide a written recommendation regarding whether the those plans satisfy the drilling criterion in the COSG Agreement."[17]

Witness Vancas adds that BHUH (not Black Hills/NE) would hire the services of an Accounting Monitor subject to Commission approval. He states,

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[16] Exhibit MJM-2 Cost of Service Gas Agreement – Article 1 – Definitions.
[17] Direct Testimony of Ivan Vancas at Page 15, lines 18-23

"The Accounting Monitor, also an independent third party not affiliated with the Company or BHUH, would conduct annual assessments of BHUH's calculations under the COSG Program as provided by the COSG Agreement and provide an assurance report of its findings for the Commission."[18]

The COSG Plan Agreement has two sections dealing with oversight, which is supposed to provide the ratepayer protections that the Company believes will satisfy the Commission and interested stakeholders, including the Public Advocate. Section 4.4 *Five-Year Drilling Plan Review* states,

> "No later than seventy (70) calendar days before each Five-Year Anniversary, BHUH shall provide the Hydrocarbon Monitor with the information described in Section 4.2(iii)-(xiv)[19] for each Property, the Utilities' aggregate Hedge Target for each remaining year in the twenty (20) year period following the First Acquisition Date, and an updated Drilling Plan for each Property for such period."[20]

After being provided the information listed above, the Hydrocarbon Monitor has 10 calendar days to issue a written report to BHUH, the Company, and the Commission concerning whether the drilling plan meets the "Drilling Plan Criterion."[21] If, in the opinion of the monitor, the plan does not meet the criterion, no new acquisitions are added to the agreement. However, if the

[18] Direct Testimony of Ivan Vancas at Page 16, lines
[19] See list earlier in this testimony.
[20] The COSG Agreement will also include a provision wherein BHUH can update the plan with additional reserves anytime within the 5 year planning horizon provided that BHUH provides the Hydrocarbon Monitor with the information described in Section 4.2(iii)-(xiv) for the Property, the Utilities' aggregate Hedge Target for each remaining year in the twenty (20) year period following the First Acquisition Date, and an updated Drilling Plan the Property for such period.
[21] Exhibit MJM-2 - Appendix 2 to the COSG Plan Agreement

monitor approves the plan, a 60-day clock starts within which the Commission and interested stakeholders have to conduct an adjudicative proceeding to evaluate the plan, at the end of which the Commission must decide whether to approve this five-year drilling plan. There are several "if-then" stipulations in the COSG Plan Agreement should the Commission fail to approve or should one of the other jurisdictions not approve the plan. The bottom line is that, if the Commission approves this agreement, it is approving a locked-in and short-review period to determine the reasonableness of what will in all likelihood be millions of dollars of investment and operations costs for natural gas reserves that could be located anywhere in the mid-west.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE EXPEDITED REVIEW?

A. My concerns are: (1) there is a very short 60-day adjudication period, (2) the agreement presumes reliance on so-called independent technical and financial monitors, (3) the plan is for five years but can be amended anytime during the plan (assuming the monitors agree), and (4) there is an extensive list of information that would have to be reviewed which would surely stretch and tax the limited resources of the Commission and the Public Advocate

2. Ability to review.

Q. HAVING REVIEWED THE COMPANY'S RESPONSES AS TO THE EXPERTISE NECESSARY TO EVALUATE POTENTIAL ACQUISITIONS, DO YOU BELIEVE

THAT THE NEBRASKA PUBLIC SERVICE COMMISSION OR THE NEBRASKA PUBLIC ADVOCATE HAS ADEQUATE RESOURCES TO MAKE AN EDUCATED RECOMMENDATION IN THAT REGARD?

A. No. In fact the Company acknowledges this lack of expertise. Exhibit MJM-3 (Black Hills/Nebraska's response to PA-33) shows that the Company was asked, "Does Black Hills believe that approval of reserve acquisitions and drilling plans is within the Commission's and the PA's expertise? Does Black Hills expect the Commission and the Parties to contract for such expertise, or are the Hydrocarbon Monitor and Accounting Monitor intended to fulfill such needs?" The Company's response acknowledged the lack of expertise and then dismissed it by stating, "Where Commissions, Boards and Consumer Advocates may lack the personnel with technical expertise and experience with natural gas production to monitor each aspect of the functions of the COSG Program and/or to evaluate and approve reserve acquisitions, the COSG Program incorporates assistance for the Commission, its staff, and consumer advocates."[22] The Company then goes on to say the two monitors will fill in for this lack of expertise.

Q. **DOES THAT ADDRESS YOUR CONCERN?**

A. No. For there to be some level of independence, at the very least, these monitors should be selected by the Commission, not just approved. It is quite common for Commissions to select auditors to review a utility's operations,

[22] Exhibit MJM-3 – Black Hills/NE response to PA-33.

finances, and overall management and then have the utility pay for the cost either by direct payment to the auditor or by reimbursing the Commission. But, in those cases, the auditor is selected by the Commission, ensuring a greater degree of independence. Further, and with specific reference to the hydrocarbon monitor, this would undoubtedly involve in-depth knowledge of the industry and specific professional competence, regarding which the Commission has little, if any, background or expertise. As for the Public Advocate, based on discussions with counsel, there is no expertise within the PA office to conduct the type of review that would be required either in the five-year drilling plan or any new acquisitions. That consideration does not even address the cost of obtaining any outside assistance that the PA would require in the expedited 60-day review process.

Q. GIVEN THE COMPLEXITY OF THE NATURAL GAS INDUSTRY AND WITH THE AMOUNT OF INFORMATION THAT WOULD BE PROVIDED BY THE COMPANY, IS IT YOUR OPINION THAT 60 DAYS IS A SUFFICIENT PERIOD OF TIME FOR THE COMMISSION AND THE PUBLIC ADVOCATE TO EVALUATE POTENTIAL ACQUISITIONS BY COSGO OR THE FIVE-YEAR DRILL PLAN OR ANY ACQUISTION?

A. As I established earlier in this testimony, there is a significant amount of information that will come with the five-year drilling plan or with individual acquisitions once the plan is in place. The Company, to this point, has refused to disclose how many potential acquisitions may be in the first plan.

Therefore, neither the Commission nor the Public Advocate or any of the intervenors have any idea what to expect in terms of how much is going to be reviewed. It is unreasonable to think, considering the sheer volume of information that will be presented, that it can be adequately reviewed in 60 days. It took more than 60 days to move from the planning conference to the filing of this testimony in this docket (i.e., November 16 to February 16 is 92 days), and we did not even have a single actual acquisition to review.

Q. **ARE THESE CONCERNS ADDRESSED BY THE COMPANY'S STATED WILLINGNESS TO PROVIDE THE MONITOR WITH DATA EARLIER UNDER CONFIDENTIALITY AGREEMENTS?**

A. No. Just because the monitors may have access to the data under the cloak of confidentiality does not mean that it will be reliable for the purposes of setting the hedge costs. The information is not beneficial to the Commission or Public Advocate until it can be reviewed.

D. Modeling, Forecast Assumptions, and Hypothetical Approval

Q. **WHAT ARE YOUR CONCERNS WITH THE MODELING, FORECAST ASSUMPTIONS, AND HYPOTHETICAL APPROVAL?**

A. While the Company has gone to great lengths to show how the hedge costs (or credits) would be calculated, the entire process is hypothetical. The Company has not provided any factual numbers for anyone to review and validate and test the assumptions in the model. I will acknowledge that

Company Witness Aaron Carr has presented a very detailed and integrated model that could be a useful economic tool if we had real numbers with which to work, but that is simply not the case. In fact, Witness Carr acknowledges this in his testimony when he states,

> "The model was compiled on a ***hypothetical cost of service program*** [***emphasis added***] to educate and inform the parties to this docket as to the mechanics and formulas driving the effective cost of gas under the COSG Program and illustrate the regulatory-like functionality of the COSG Program parameters consistent with the COSG Agreement (i.e. revenue requirements, cost of service recovery, regulated cost of capital, etc.)".[23]

Obviously, the Company's purpose here is to gain acceptance and approval of the formulas and algorithms in the model and then use it to develop the hedge costs (or credits). Based on my review of the model, I do not see a problem with what it attempts to calculate or how it is working. However, because the Commission is being asked to approve the COSG Program based on a hypothetical model, I do have some concerns with some aspects of the way the model is purportedly going to be used.

Q. PLEASE CONTINUE.

A. I am concerned with the variability of the natural gas forecasts that, combined with the hypothetical information provided, makes it virtually

[23] Direct Testimony of Aaron Carr at page 20, lines 8-12

impossible to know when, and even if, customers will start to see benefits from the COSG program.

Q. PLEASE EXPLAIN

A. As hypothetically proposed in the Company's financial model (See CONFIDENTIAL Exhibit AC -2), the Company hypothetically estimates, based on a fictitious level of production from some unknown resource and 100% participation by all BHUH utilities, that customers would see a net benefit of [redacted] million on a NPV basis for the first 10 years of the plan (2016-2015).[24] Reviewing this further shows that in the first four years, customers would be expected to pay a premium (or hedge cost) of [redacted] million, [redacted] million, [redacted] million, and [redacted] million for the years 2016-2019, respectively; a total of [redacted] million before customers ever start to realize benefits in the COSG program. This scenario is caused by the initial start-up and cash outlays as acquisition and production activities ramp up. However, if I simply update the forecast of natural gas market prices based on current EIA data based on a report release on February 8, 2016 and then escalate the 2017 cost of natural gas at Henry Hub presented in that report using the imbedded escalation rate in the Company's forecast, the net benefits shrink to [redacted] (as opposed to the Company's forecast of [redacted] million) for the same 10-year period. In fact, with this forecast, customers end up paying [redacted] million on an NPV basis in the first 10 years for the privilege of participating in the COSG

[24] Exhibit AC-2 Tab marked Outputs Col F, Line 28

Program. Further, the amount that customers see in a hedge costs in the first four years rises to [redacted] million. I have included as Exhibit MJM-4 the derivation of my calculations using the updated and escalated EIA data.

Q. IS THERE ANY EVIDENCE THAT THE NATURAL GAS FORECAST PRICES THE COMPANY USED ARE OVERSTATED OR HIGH?

A. I believe there is. In her testimony, Company Witness Ryan presents Figure 6 on page 24 that shows the forecast for natural gas from 2016 through 2034. That chart shows that the EIA reference case forecast for natural gas would be [redacted] in 2015 and escalate to [redacted] per MMBtu in 2034. This is the same information that Company Witness Carr uses in the hypothetical model to generate the hypothetical [redacted] in NPV benefits to customers. However, in Exhibit MJM-5, the EIA report issued in February 2016 shows that natural gas prices are substantially lower than was forecasted as recently as last April. The table below shows the two data sources below for side by side comparison. To arrive at an estimate of the long term forecast, I simply applied the embedded escalation rate in the April 2015 forecast and applied that to 2017 to 2034. EIA will issue a new long term forecast in April. The costs in columns (d) and (e) are what I used to generate the example contained in MJM-4.

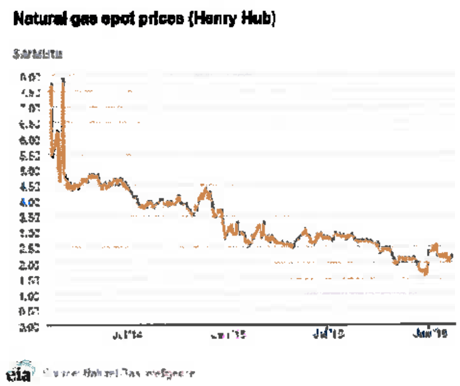
Table 1 – Derivation of Price for Sensitivity Analyses
Company as Filed vs. EIA Latest Report
$ per MMBtu

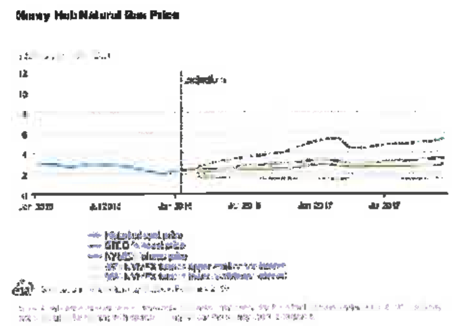
Year	Company As filed ($ per mmbtu)	Escalation Rate	EIA Short Term Outlook ($ per mmbtu)	Escalated
(a)	(b)	(c)	(d)*	(e)=(d)*(c)
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]

This difference in price forecasts alters the model's results dramatically.

Q. **IS THERE ANY RECENT EVIDENCE THAT PRICES MAY STAY LOWER THAN THAT THE COMPANY PREDICTED WHEN IT FILED THIS APPLICATION?**

A. Yes. The figure below shows EIA short-term outlook for natural gas prices in 2016 and 2017. In this figure, the January 2015 spot price is less than $3.00 per MMBtu. Yet, both the figures in table 1 above show 2015 as being well above that amount at [redacted] and [redacted] per MMBtu. The second chart is a reproduction of an EIA short-term forecast that shows the NYMEX spot price through the end of 2017 being less than [redacted] per MMBtu. This is the basis of my analysis in MJM-4.





Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. I conclude that (a) the financial model is very sensitive to changes in the forecasted price of natural gas on the open market (i.e., if prices remain low, the potential benefits of the COSG Program are significantly dampened and may all but disappear); (b) the fact of a wide variability in forecasts due simply to when one reviews the forecast, in conjunction with all the other assumptions that could adversely affect ratepayers, makes basing any decision about the long-term benefits too risky to pursue.

E. Impact of disapproval by one or more other Commissions

Q. WHAT ARE YOUR CONCERNS RELATED TO THE MULTI-JURISDICTIONAL APPPROVAL OF THIS COST OF SERVICE GAS PROGRAM?

A. As I mentioned earlier in my testimony, BHUH's individual operating companies in Colorado, Iowa, Kansas, South Dakota, and Wyoming have filed similar requests for approval of essentially the same program in those respective jurisdictions. In fact, some of the testimony is nearly duplicative among the jurisdictions. Further, there have been hundreds, if not thousands of information requests issued across the six jurisdictions, many looking at the same issues that I have addressed here in this testimony. Further, the Public Advocate in Iowa has already filed testimony in dockets SPU-2015-0028, WRU-2015-0032-0225, and TF-2015-0327 before the Iowa Utilities Board.[25] In Kansas, Staff and CURB are expected to file their testimony on March 21 with cross hearing starting on March 28. The other jurisdictions each have their own schedules to review their respective BHUH operating company's application. My concern is that if one or more of these commissions or boards do not approve the plans in their jurisdictions, the remaining operating companies will be left to shoulder the burden of the costs that would have been allocated to and paid for by the other operating company(ies) not receiving approval for the COSG Plan. It is important to note that even one of the other jurisdictions not participating will have an impact to this jurisdiction. The table below shows the allocation that will be used in the Company's model to calculate the hedge costs/credits.

[25] See Direct Testimonies of Marco Munoz, Blake J. Kruger and Brian W. Turner

Table 2 – Allocation percentages based on Jurisdiction Demand

	As Shown in COSG Model		With Iowa Out			
State	Annual Demand (mmbtus)	Allocation%	Annual Demand (mmbtus)	Allocation%	Change in Allocation	% Change in Allocation
(a)	(b)	(c)	(d)	(e)	(f)	(g)
Iowa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kansas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nebraska	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Colorado	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wyoming	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
South Dakota	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]		

Source: Exhibit AC-2 COSG Model - Tab marked Financial Model Col F, lines 165-171

As this table shows, Black Hills/NE customers will shoulder [redacted] (Col c) of the costs for the COSG Program if 100% of the jurisdictions approve the plan. However, in column (e), I have removed Iowa's firm demand of [redacted] and recalculated the allocation. Indeed, Nebraska and all the other jurisdictions receive a [redacted] (column [g]) increase in the amount of costs that will be allocated to them. This is one major reason that the Company's plan is unworkable with respect to Nebraska public interest in that it involves too many variables and unknowns. If just one out of the five jurisdictions with substantial demand fails to approve the Company's proposal, a major cost shift occurs. Further, because of the hypothetical information provided in the filing, we have no way to discern the exact impact should one or more companies not participate because a commission or board failed to approve. Here to is another reason why this plan is untenable.

Q. HAS THE COMPANY MADE ANY COMMENTS ABOUT THIS CONCERN?

A. Yes. In Constellation NewEnergy-Gas Division, LLC, (CNEG) data request No. 1-12 (Exhibit MJM-6), the Company was asked this question:

> If the public utility commissions concurrently reviewing the COSG Program decline to approve the Program, does Black Hills intend to purchase natural gas reserves without the guaranteed cost recovery proposed through the Program?"

The Company provided the following response:

> "BHUH would not acquire reserves to provide a long-term supply hedge to utility customers absent the COSG Program. Within the Black Hills family of companies, only BHEP acquires and develops properties as a traditional exploration and production company. If BHEP did acquire or develop reserves, absent the COSG Program, those reserves would not specifically be developed for the Black Hills utilities."

Therefore, without a pre-approval of the program, BHUH will not pursue the program for its customers.

Q. DID THE COMPANY PROVIDE ANY SORT OF BREAK-EVEN POINT AT WHICH THE PROGRAM MIGHT NOT MOVE FORWARD?

A. No. They left the decision open until they have resolution from jurisdictions in which they have filed for pre-approval of the program. In response to Request No. PA-4 (Exhibit MJM-7), the Company stated, "Once BHUH knows the actual portfolio percentage commitments from the other multiple states in which Black Hill Utilities have applied, **then it will reevaluate the feasibility of continuing the COSG Program**" [**emphasis added**].

Q. DID THE COMPANY ADMIT THAT THERE HAS TO BE A CERTAIN LEVEL OF PARTICIPATION IN THE PROGRAM TO MAKE IT VIABLE?

A. Yes. Witness Vancas clearly makes this point in his direct testimony in which he states, "The Company may or may not pursue the COSG Program depending on the levels of volumes the Commission orders to be hedged. There has to be a level of scale to the COSG Program to minimize administrative and other costs and to facilitate a reasonable COSG price to customers that would make the COSG Program viable."[26]

From this statement, several scenarios emerge, and there is no way to be sure whether in the end Black Hills/NE customers will be better off than maintaining the status quo. Here again, too many unknowns exist for the Commission to grant approval for a program with significant cost implications to customers.

F. Termination Clause

Q. PLEASE DESCRIBE YOUR CONCERN WITH THE TERMINATION CLAUSE?

A. With respect to the Company's ability to terminate its participation in the COSG Program, I am concerned that the termination clause of COSG Agreement may usurp the Commission's ability to ensure just and reasonable rates for Black Hills/NE customers.

Q. PLEASE EXPLAIN.

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[26] Direct Testimony of Ivan Vancas page 22, Lines 18-22

A. Included in the COSG Agreement is a whole section on termination. Section 6.2 - Early Termination by Utility reads:

> If a Utility is ordered by its PUC to terminate its rights and obligations under this COSG Agreement before the end of the Term, the Utility shall provide notice to BHUH. Upon receipt of a termination notice, BHUH shall cause COSGCO to sell, as soon as practical, an interest in the Properties (but excluding any Property and/or wells for which the terminating Utility is a Non-Participating Utility) that is functionally equivalent to the terminating Utility's Percentage Share for the calendar year in which such sale(s) closes, <u>provided that no sale(s) shall occur until the remaining Utilities have approved the interest to be sold and the terminating Utility has approved the sale price(s)</u>. Following the sale, Investment Base shall be adjusted to reflect such sale(s). The termination of the terminating Utility's rights and obligations under this COSG Agreement shall be effective at the end of the calendar month in which the sale (or, if COSGCO sells such interest through multiple transactions, the last sale) closes, provided that (i) any amount due under Section 6.4 and any reconciliation amount owed under Section 5.3 shall be promptly paid, (ii) <u>until such sale closes</u>, the terminating Utility shall continue to receive any credits and incur any costs required under ARTICLE 5, and (iii) **<u>if no third party(ies) is willing to purchase such interest, the terminating Utility shall remain bound to this COSG Agreement until the end of the Term [emphasis added].</u>**

Q. YOU HAVE HIGHLIGHTED PART 3 OF THIS SECTION. PLEASE DESCRIBE YOUR CONCERNS WITH IT.

A. In stating my concern, I will describe a hypothetical but reasonable termination scenario by Black Hills/NE that could develop. First, assume that the Commission approves the Company's participation in the COSG Program and allows the Company to enter/sign the COSG Agreement with BHUH. Second, assume that the first set of acquisitions is approved in the first drilling plan. After a year passes, the first report is issued and, in our scenario, costs are significantly higher than expected and the hedge cost calculation shows a significant cost to customers. The Commission would review this situation (in its abbreviated 60-day review cycle) and, most likely, determine that it would want Black Hills/NE to terminate its interest in the program. Black Hills/NE would then notify BHUH per the provisions of Section 6.2, but would not be free from the agreement because of the terms of 6.2 which states that before release, the Company's interests in the COSG Program have to be sold to either a third-party or possibly to the remaining utilities in the COSG Program. Please note that the remaining utilities are under no obligation to purchase a terminating utility's interest and are not obligated to absorb the costs allocated to the terminating utility. As such, Black Hills/NE would be obligated to continue to pay for its allocated share until a suitable and approved buyer could be found. Bear in mind that the underlined provision, "*provided that no sale(s) shall occur until the remaining Utilities have approved the interest to be sold,*" makes it clear that one or more of the other utilities could negate any potential sale transaction. Additionally, in Section 6.2 ii, Black Hills/NE would continue to be bound to the agreement until the sale closed no matter how long it took. Finally, if no third party could be found (which would be the likely scenario if the Commission were to order Black Hills/NE to terminate the agreement since the circumstances would make the deal unattractive to any other party), the bolded/underlined section makes clear that Black Hills/NE would be obligated to the terms of the agreement, notwithstanding the Commission's directive to terminate the agreement.

Q. DID THE COMPANY MAKE ANY STATEMENTS IN DISCOVERY ON THIS ISSUE?

A. Yes. In response to Data Request CNEG 1-16 (Exhibit MJM-8), in which the Company was asked, "Please explain the Company's understanding of the Commission's authority if, at some point after approval of the proposed COSG Program, the Commission determines the COSG Agreement is no longer in the best interest of the ratepayers," the Company responded,

> "If the Commission approved the COSG Program and the COSG Agreement, the Commission would have the authority not to approve acquisitions or drilling programs. See COSG Agreement, Article IV. If the Commission approved an acquisition and drilling program, the Company would be required to satisfy any obligations associated with that acquisition and drilling program, in the same way **the Company is required to perform its obligations under other utility-related agreements approved by the Commission, regardless of whether the Commission later believed the contract was no longer in the best interest of ratepayers**. As such, the Company would not expect that the Commission would attempt to cause the Company to breach its obligations under the agreement" (emphasis added).

The highlighted section summarizes the totality of the rigidness of the Company position. Black Hills/NE is requesting approval of a program and agreement that could cost ratepayers millions of dollars based on hypothetical numbers but once approved, the utility is "**required to perform its obligations under other utility-related agreements approved by the Commission, regardless of whether the Commission later believed the contract was no longer in the best interest of ratepayers**."[27]

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW AND ANALYSIS?

A. When I look at all the facets of the COSG Program and the related agreement, I come to the conclusion that this program with its rigid termination clause, has too many unknowns, improperly shifts risk to ratepayers with too many possibilities that ratepayers may not benefit from the program. As such the Cost of Service Gas Program, as proposed, is not in the public interest and should be rejected by the Commission.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

[27] Exhibit MJM-8

ATTACHMENT A

Professional Experience and Education of Michael J. McGarry Sr

Summary

Mr. McGarry's professional experience spans thirty-three years within the private and public sectors. He has been a project manager of numerous rate case and management audit reviews for commissions and public advocates in addition to testifying in a number of jurisdictions. He is knowledgeable and well-versed in the issues facing the energy industry with respect to renewable energy resources, alternative rate plans, cost unbundling, rate case management, and regulatory affairs. His regulatory auditing and affairs experience includes managing rate case audits and managing rate cases for commissions, attorney general offices, and consumer advocates. In addition, Mr. McGarry has conducted over 30 management and operational audits which, in most cases, evaluated management decisions and actions in light of information that was known to utility executives and managers at the time decisions were made or actions were taken. Topics of these included fuel procurement, environmental compliance strategy, customer service, renewable energy, and others.

Selected Professional Experience

Audits - Utility Management and Operational

Mr. McGarry has conducted comprehensive management and operational audits of investor-owned energy, telecommunications, and water utilities, including audits on most functions within the utility environment including affiliates transactions, capital and operating budget processes and practices, crew operations, commodity trading, construction program practices, corporate governance, demand side management, distribution operations and maintenance, fuel procurement, internal auditing, strategic planning, and supply chain management.

- On behalf of the Connecticut Public Utilities Regulatory Authority, Diagnostic Management Audit of all functions of Yankee Gas Services Company. June 2014-present. Co-Project Manager.
- On behalf of the Maine Public Utilities Commission. Management audit of Central Maine Power Company's (CMP) Advanced Metering Infrastructure (AMI) project in Docket No. 2013-00168, September 2013-April 2014. Project Manager. Led team of consultants to assess the effectiveness of Central Maine Power Company's AMI project management, compliance with Commission directives, the estimated versus actual cost and savings, and the program's capabilities.
- On behalf of the Public Advocate of Nebraska, Nebraska PSC. Assistant Project Manager. Supported the Public Advocate with a review of the adjustment to

customer charges to reflect the company's infrastructure system replacement cost recovery charge.

  - NEPSC Application No. NG-0074, Black Hills/Nebraska Gas Utility Company, LLC, d/b/a Black Hills Energy, July-November 2013.
  - NEPSC Application No. NG-0072, SourceGas Distribution, LLC, March 2013-May 2013.

- On behalf of the Staff of the Public Utilities Commission of Ohio (PUCO). Assistant Project Manager. Participated on a team of consultants engaged to review and ensure the accuracy and reasonableness of the Companies' compliance with its Commission-approved infrastructure cost recovery rider filings. The review included a detailed mathematical verification and validation of the support of the riders' revenue requirements model, development of sensitivity analysis that supported the PPS sampling techniques used to isolate specific plant work order for further testing.
  - Case No. 12-2855-EL-RDR: Delivery Capital Recovery (DCR) Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), December 2012-July 2013.
  - Case No. 11-5428-EL-RDR: DCR Rider Audit of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies), November 2011-May 2012.
- On behalf of the Massachusetts Department of Public Utilities, Case No. D.P.U. 08-110: Regarding the Petition and Complaint of the Massachusetts Attorney General for an Audit of New England Gas Company, February-August 2010. Project Manager. Managed a project team of accountants and industry specialists who were responsible for evaluating the accuracy of the accounting records, practices and procedures used in the development of the Company's revenue requirements calculations in the Company's base rate request.
- On behalf of the Staff of the Public Utilities Regulatory Authority of Connecticut Docket (CTPURA) #07-07-01 Diagnostic Management Audit of Connecticut Light & Power Company, July 2008-June 2009. Project Manager. Performed overall day to day project management responsibilities to conduct a diagnostic management audit of the Connecticut Light & Power Company (CL&P). Managed a project team of accountants, engineers and industry specialists who were responsible for evaluating the effectiveness of the management and operations of all aspects of the company. In addition, managed a focused prudency review of Northeast Utilities' (CL&P's parent company) development and implementation of a $122M customer information system known as CustomerCentral or C2.
- On behalf of the Staff of the Public Utilities Commission of Ohio. Project Manager. Oversaw multi-discipline team of accountants, auditors, engineers and analysts to conduct a comprehensive rate case audit of the Company's gas base rate filing. Primary goal of project was to validate information in filing, provide findings conclusions and recommendations concerning the reliability of information and

data in the filing and support Staff in its evaluation of the reasonableness of the filing.

- Case #08-0072-GA-AIR: Columbia Gas of Ohio, April-August 2008
- Case #07-0829-GA-AIR: Dominion East Ohio, November 2007-July 2008
- Case #07-0589-GA-AIR: Duke Energy Ohio, November 2007-Februrary 2008

- Co-sponsored between NW Natural, Oregon Public Utilities Commission (ORPUC) Staff, Northwest Industrial Gas Users, Citizens Utility Board, Docket No. UP205: Examination of NW Natural's Rate Base and Affiliated Interests Issues, August 2005-January 2006. Project Manager. Led a team that conducted a management audit of NW Natural Gas that included an evaluation of rate base issues for Financial Instruments (gas and financial hedging) Deferred Taxes, Tax Credits, Cost for a Distribution System, Security Issuance Costs and AFUDC calculations as well as Affiliate Transactions for Cost Allocations and Transfer Pricing, Labor Loading, Segregation of Regulated Rate Base and Subsidiary Investments and Properties, and validation of tax paid from/to affiliates are proper. Audit was to ensure Company compliance with orders, rules and regulations of the ORPUC, with Company policy and with Generally Accepted Accounting Principles.
- Consultant. As part of a team that conducted a comprehensive management audit of the management and operations of Southern Connecticut Gas, completed the capital budgeting area of the audit.
- Focused review of the preparedness of Rochester Gas and Electric (RG&E) and Consolidated Edison (ConEd) for competition in the electric industry. Evaluated all aspects of the company's management actions to prepare for competition including strategic planning, goals and objectives and senior management's attention to the company operations in a de-regulated industry
- New York Public Service Commission (NYPSC), Case 93-E-0918: Operational Audit of the Demand Side Management Function at RG&E, Commission Staff. Comprehensive operational audit of the demand side management function including program planning, management and energy savings verification. Developed and supervised the implementation of the work plan.
- NYPSC, Case 92-W-0030: Operational Audit of Jamaica Water Operations and Management, Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, and specific topics areas including engineering, contracting, and information technology. Findings led to prudence proceeding.
- NYPSC, Case 92-M-0973: Management Audit of RG&E, Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, supervision of staff and specific topics areas including purchasing and internal controls.
- NYPSC, Case 91-C-0613: Operational Audit of the Outside Plant Construction and Rehabilitation Program of New York Telephone Company, Commission Staff.

Comprehensive operational audit of the company's management and implementation of a $150M capital program to rehabilitate the outside plant distribution network. Served as Staff Examiner responsible for crew supervision, goals monitoring, contractor oversight, and report preparation.

- NYPSC, Operational Audit of the Fuel Procurement and Contracting of Long Island Lighting Company (LILCO), Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project.
- NYPSC, Operational Audit of the Fuel Procurement and Contracting of ConEd, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project
- NYPSC, Case 90007: Operational Audit of the Fuel Procurement and Contracting of Central Hudson Gas and Electric, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project
- NYPSC, Operational Audit of Fuel Procurement and Contracting of Orange & Rockland Utilities, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project
- NYPSC, Operational Audit of the Fuel Procurement and Contracting of RG&E, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on nuclear fuel. Provided research and data evaluation expertise.
- NYPSC, Case 88005: Operational Audit of Materials and Supply Function at National Fuel Gas, Commission Staff. Comprehensive operational audit of the materials and supplies function including warehouse operations, inventory control and procurement. Developed and implemented the work plan for this project.
- NYPSC, Case 87003: Operational Audit of the Homer City Coal Cleaning Plant (HCCCP), Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on the construction of the HCCCP jointly owned by New York State Electric and Gas (NYSEG) and Penelec. Responsible for fuel and construction costs analysis, benchmarking costs and alternative methods for meeting EPA Clean air restrictions, contracting practices and report preparation.
- NYPSC, Case 87003: Operational Audit of the Fuel Procurement and Contracting of NYSEG, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis, benchmarking costs, contracting practices and report preparation.
- NYPSC, Case 86007: Operational Audit of the Field Crew Supervision and Utilization of NYSEG, Commission Staff. Comprehensive operational audit to

determine effectiveness of field crew utilization and supervision. Staff examiner responsible for verifying supervisor activities, reporting, goals attainment and report preparation.

- NYPSC, Case 86005: Operational Audit of the Fuel Procurement and Contracting of Niagara Mohawk Power Company (NIMO), Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis and benchmarking costs, contracting practices and report preparation.
- NYPSC, Case 85001: Operational Audit of the Research and Development Function of ConEd, Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on R&D activities. Staff examiner on the project responsible for reviewing projects documentation and control, outside contracting a report preparation.

Cost Allocation, Cost of Service, and Rate Design

- MPSC Case No. U-17688, on behalf of the Michigan Attorney General in the matter of the MPSC's own motion to commence a proceeding to implement certain recently enacted provisions of Public Act 169. October 2014 to present. Project Manager and Testifying Witness. Analyzed and testified before the Commission regarding Consumer Energy's application with respect to proposed changes to cost allocation methodologies among various customer classes and rate design methods
- MPSC Case No. U-17689, on behalf of the Michigan Attorney General in the matter of the MPSC's own motion to commence a proceeding to implement certain recently enacted provisions of Public Act 169. October 2014 to present. Project Manager and Testifying Witness. Analyzed and testified before the Commission regarding DTE Energy Company's application with respect to proposed changes to cost allocation methodologies among various customer classes and rate design methods.

Hedging

- On behalf of the Vermont Public Service Department in the matter of the review of filings made by Vermont Gas Systems (VGS) pursuant to its Alternative Regulation Plan, September 2013-present. Project Manager. Led a team of consultants in reviewing VGS's hedging and benchmarking information to ascertain company practices and provide recommendations to improve strategy and credit risk level.
- Before the Utah Division of Public Utilities (UTDPU), Docket No. 09-035-15: In the Matter of the Application of Rocky Mountain Power (RMP) for Approval of its Proposed Energy Cost Adjustment Mechanism (ECAM) - Net Power Cost Evaluation (NPC), RMP 2009 General Rate Case, July-December 2009. Project Manager and Testifying Witness. Analyzed the reasonableness and technical accuracy of the RMP's NPC request, performed a comprehensive review of the Company's NPC estimate and developed recommendations to ensure an accurate baseline for the ECAM, analyzed special issues addressed in the NPC portion of

the case, analyzed the Company's fuel price hedging policies and provided recommendations appropriate for the ECAM, and reviewed intervener NPC issues as well as analyzing additional issues as raised by the Company and testified to hedging issues.

- On behalf of the Staff of the Delaware Public Service Commission (DEPSC), Docket No. 07-239F: In the matter of the application of Delaware Power & Light (DPL) for approval of modifications to its gas cost rates, October 2007-April 2008. Project Manager and Testifying Witness. Oversaw review of DPL gas hedging program.
- On behalf of the Staff of the DEPSC, Docket No. 06-287: In the matter of Chesapeake Gas Corporation's implementation of a Gas Hedging program, June-August 2007. Project Manager. Provided industry expertise and suggestions to the Commission on a proposal plan to implement a gas hedging procurement program at the Company.

Natural Gas Cast Iron Main Replacement

- On behalf of the MIAG, Case No. U-16407: In the matter of the application of Michigan Consolidated Gas Company (MichCon) for approval of a detailed plan for gas main renewal, including a long-term plan to significantly reduce the amount of cast iron main in its system. Nov 2010-May 2011. Project Manager and Testifying Witness. Reviewed Company's proposed plan with respect to whether a cost recovery mechanism can be designed to minimize the impact on ratepayers. Testified as to the reasonableness of cost benefit of replacements as well as to the capital cost recovery as it affects future rate cases.
- On behalf of Maine Public Advocate (MeOPA), Case No. 2008-151: Maine Public Utilities Commission (MEPUC) Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s (NUI) Cast Iron Facilities (Phase II), July 2008-July 2010. Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to follow-up on investigation for the need for the program and the Company's management of the repair or replacement of its cast iron facilities.
- On behalf of MeOPA, Case No. 2004-813: MEPUC Investigation into Maintenance and Replacement Program for NUI's Cast Iron Facilities (Phase I), November 2004-March 2005. Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the MeOPA to investigate the need for the program and the company's management of the repair or replacement of its cast iron facilities.

Power, Fuel & Gas Cost Recovery

Supported the Michigan Attorney General (MIAG) with analysis and/or testimony in Power Supply (PSCR) and Gas Cost Recovery (GCR) cases. Issues included: prior year under-recovery of power supply costs, under-recovery of cumulative Pension Equalization Mechanism costs, over-refund of the companies' residual Self-Implementation Refund, the companies' claimed credit to PSCR costs related to credit claimed by affiliate, regulatory asset recovery surcharges asset and liability balance resulting in over recovery, Reduced Emissions Fuel (REF) prudency and calculation of REF impacts, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of mercury filter expenses and coal refinement expenses, transfer price for renewable energy sources, replacement power costs, inclusion of excess fuel and variable O&M expenses proffered by various intervenors, Karn 1 outage delay and Rate E-1 discount recovery, and hedging on gas procurement.

- Case No. U-17095-R. Consumers Energy Company 2013 PSCR Plan reconciliation. July-November 2014. Project Manager and Testifying Witness.
- Case No. U-17097-R. Detroit Edison Company 2013 PSCR Plan reconciliation. July-Nov 2014. Project Manager and Testifying Witness.
- Case No. U-17319. Detroit Edison Company 2014 PSCR Plan. February-August 2014. Project Manager and Testifying Witness.
- Case No. U-16892-R. Detroit Edison Company 2012 PSCR Plan reconciliation. May-December 2013. Project Manager and Testifying Witness.
- Case No. U-17097. Detroit Edison Company 2013 PSCR Plan. February-April 2013. Project Manager and Testifying Witness.
- Case No. U-16434-R. Detroit Edison Company 2011 PSCR Plan reconciliation. June 2012-February 2013. Project Manager and Testifying Witness.
- Case No. U-16892. Detroit Edison Company 2012 PSCR Plan. November 2011-May 2012. Project manager and Testifying Witness.
- Case No. U-16047-R. Detroit Edison Company 2010 PSCR Plan reconciliation. August 2011-March 2012. Project Manager and Testifying Witness.
- Case No. U-16432. Consumers Energy Company 2011 PSCR Plan. February-June 2011. Project Manager.
- Case No. U-16434. Detroit Edison Company 2011 PSCR Plan. February-June 2011. Project Manager and Testifying Witness.
- Case No. U-15675-R. Consumers Energy Company 2009 PSCR Plan reconciliation. October 2010-January 2011. Project Manager and Testifying Witness.
- Case No. U-15677-R. Detroit Edison Company 2009 PSCR Plan reconciliation. September-December 2010. Project Manager and Testifying Witness.
- Case No. U-16047. Detroit Edison Company 2010 PSCR Plan. January-May 2010. Project manager and Testifying Witness.
- Case No. U-15415-R. Consumers Energy Company 2008 PSCR Plan reconciliation. May-November 2009. Project Manager and Testifying Witness.
- Case No. U-15677. Detroit Edison Company 2009 PSCR Plan. January-June 2009. Project Manager.
- Case No. U-15415. Consumers Energy Company 2008 PSCR Plan. January-March 2008. Project Manager.
- Case No. U-15320. Midland Cogeneration Venture Limited Partnership (MCV) elimination of "availability caps" which limit Consumers Energy Company's recovery of capacity payments with respect to its power purchase agreement with MCV. October 2007-June 2008. Project Manager.

- Case No U-15040. Michigan Gas Utilities Corporation 2007/08 GCR Plan. March-August 2007. Project Manager and Testifying Witness.
- Case No. U-15001. Consumers Energy Company 2007 PSCR Plan. November 2006-August 2007. Project Manager and Testifying Witness.
- Case No. U-14701-R. Consumers Energy Company 2006 PSCR Plan reconciliation. June-November 2007. Project Manager and Testifying Witness.

Project Management

- Mr. McGarry's experience includes management of multi-discipline teams for a wide range of client engagements, development and implementation of detailed work plans and project schedules. He has analyzed and planned interdivisional resource utilization; supervised, developed and coached interdivisional team members; and created numerous executive reports, briefings, and presentations.

Prudence Reviews

- On behalf of the Staff of the Public Utilities Regulatory Authority of Connecticut Docket #07-07-01 Diagnostic Management Audit of Connecticut Light & Power Company (CL&P), July 2008-June 2009. Project Manager. Performed overall day to day project management responsibilities, within the context of a diagnostic management audit, to conduct a focused prudency review of Northeast Utilities' (CL&P's parent company) development and implementation of a $122M customer information system known as CustomerCentral or C2, including managing a project team of accountants, engineers and industry specialists who were responsible for evaluating the effectiveness of the management and operations of C2.
- NYPSC, Case 96-M-0858: Prudence Investigation into the Scrap Handling Practices in the Western Division of NIMO, Commission Staff and Testifying Witness. Litigated proceeding as a result of allegations of bribery and corruption in company practices related to a specific vendor who purchased company scrap metal. Led team of 10 staff examiners to quantify the extent to which the Company paid excessive rates to this vendor. Testified to the findings of the analysis. Case settled with ratepayers receiving a credit to bills
- NYPSC, Case 91-W-0583: Prudence Proceeding of the Operations and Management of Jamaica Water, Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive costs to rate payers. Testified on a Staff panel to the excessive costs associated with management's inattention to sound business practices related to the design, purchase and installation of the Company customer information system.
- NYPSC, Case 88-E-115: Prudence Proceeding to Investigate the Construction Costs Associated with the HCCCP, Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive construction charges related to the HCCCP. Testified on a Staff panel to the fuel price differential costs resulting from the failure of the coal cleaning plant to function as designed as well as surrebuttal testimony on the cost of a flu-gas de-

sulfurization plant and ancillary equipment and facilities. Case settled. Customers received $125M credit.

- NYPSC, Case 86005: Prudence Proceeding to Investigate the Fuel Procurement and Contracting Practices at NIMO, Commission Staff. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive fuel charges to customers. Responsible for fuel cost analysis and benchmarking costs, contracting practices, and testimony preparation. Case settled with customers receiving $66M credit.

Regulatory and Rate Case Management

Mr. McGarry has worked with clients to manage all aspects of the regulatory and rate case process. He has developed efficient processes to prepare supporting analyses and testimony for submission to the regulatory bodies and interveners. He is a seasoned project manager and has analytical expertise to respond to interrogatories and data requests from all rate case interveners in a timely manner. Mr. McGarry has assisted a number of clients in preparing revenue requirement and cost of service analyses. He has also developed rate structure and billing determinant information analyses, time of day and interruptible rates analyses, fuel and purchased power reports, and annual wholesale rates for member cooperatives. He has developed complex revenue requirement models to present alternative positions to a utility's proposed rate request.

- On behalf of the District of Columbia Public Service Commission (DCPSC), Formal Case No. 1106: In The Matter Of The Investigation of Washington Gas Light Company's (WGL) Interruptible Service Customer Class, the operation of WGL's Distribution Charge Adjustment, How WGL's Class Cost of Service Study Accounts For Revenues From Certain Classes Of Customers, the proper design of Interruptible Service Rates, and related issues, February 2014-present. Lead Consultant and Assistant Project Manager. Provided assistance with management of the team and schedule as well as providing support to lead consultants in their review of customer class cost of service issues.
- On behalf of the Michigan Attorney General, Case No. 17496: In the Matter of the application of Consumers Energy Company for approval of long-term power purchase auction procedures. February-April 2014. Project Manager and Testifying Witness. Reviewed the company application, other documents filed in the case, including DRs, and relevant sections of the Michigan Code of Laws in preparation for filing expert witness testimony regarding the reasonableness and prudency of the company's proposed long-term power purchase auction procedure.
- On behalf of the Georgia Public Service Commission, Docket No. 36989, Georgia Power Company's 2013 general rate case, June-November 2013. Project Manager and Testifying Witness. Led a team of consultants providing advisory services to the Commission staff with analysis of fossil fuel O&M, environmental capital cost and compliance, and transmission and distribution system costs. Provided written testimony in support of Staff's position on those issues.

- On behalf of the District of Columbia Public Service Commission (DCPSC), Formal Case No. 1103: In the Matter of the Application of the Potomac Electric Power Company (Pepco) for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service, June 2013-July 2014. Assistant Project Manager. Advised Commissioners and Staff on proposed revenue requirements, rate base, rate design, reliability projects, and cost recovery mechanism.
- On behalf of the Arizona Corporation Commission, Docket No. E-04204A-12-0504, in the matter of the application of UNS Electric, Inc. (UNSE) for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of UNSE devoted to its operations throughout the State of Arizona and for related approvals. April-November 2013. Project Manager and Testifying Witness. Oversaw analysis and assessment of the company's proposed cost of service and rate design, and energy efficiency mechanisms. Provided written testimony in support of Staff's position regarding energy efficiency mechanisms and cost adjustors.
- On behalf of Central Hudson Gas and Electric Corporation to provide assessment of its business case for the replacement of its legacy information systems platforms. January-March 2013. Project Manager and Lead Consultant. Provide review and comment on company testimony to be submitted in context of the company's general rate case which seeks concurrence and/or approval of its proposed business case.
- On behalf of the Staff of the Delaware Public Service Commission, Docket No. 12-546, Delmarva Power & Light for an increase in gas base rates. February-December 2013. Project Manager and Testifying Witness. Reviewed, analyzed, and evaluated the Company's proposed gas main extension policy as to the need, cost benefits, and the equity of distribution of costs and provided expert witness testimony on those issues.
- On behalf of the Attorney General of the State of Michigan, Case No. U-15768. Detroit Edison Company. October 2012-May 2013. Project Manager and Testifying Witness. Supported the Attorney General of the State of Michigan (MIAG) with analysis and/or testimony. Issues included: prudency of AMI investments, expenses, and cost/benefits; partial and interim rate relief; acquisitions; revenue requirements; revenue decoupling; cost of service; revenue allocation; and rate design.
- On behalf of the Staff of the Arizona Corporation Commission, Docket No. 12-0291: Application of Tucson Electric Power Company for Just and Reasonable rates and charges to realize a reasonable rate of return in Arizona, before the AZCC. August 2012-June 2013. Project Manager and Testifying Witness. Oversaw analysis and assessment of the company's proposed cost of service and rate design, cost of capital and return on equity, and energy efficiency mechanisms. Provided written testimony in support of Staff's position regarding energy efficiency mechanisms and environmental compliance adjustor.

- On behalf of the District of Columbia Public Service Commission (DCPSC), Formal Case No. 1093: In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's (WGL) Existing Rates and charges for Gas Service. July 2011-July 2013. Assistant Project Manager and Lead Consultant. Participated on a team of consultants providing advisory services to Commissioners and Staff on proposed revenue requirements, rate base, and rate design. Team analyzed revenue requirements, fuel costs, uncollectibles, environmental issues affecting rate base, inventory adjustments, plant in service, construction work in progress, research and development issues, safety initiatives, affiliate allocations, and energy funds.
- On behalf of the Staff of the DEPSC, Docket No. 11-528: in the matter of the application DPL for approval of modifications to its electric base rates, January-July 2012. Project Manager. Oversaw rate case analysis and assessment of company's proposed inter-company allocations.
- On behalf of the District of Columbia Public Service Commission (DCPSC), Formal Case No. 1087: In the Matter of the Application of the Potomac Electric Power Company (Pepco) for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service, September 2011-December 2012. Project Manager and Lead Consultant. Advised Commissioners and Staff on proposed revenue requirements, rate base, rate design, reliability projects, and cost recovery mechanism.
- Before the Arizona Corporation Commission, Docket No. 11-0224, Arizona Public Service Company Rate Case, July 2011-March 2012. Project Manager and Testifying Witness. Analyzed the Company's proposed Infrastructure Tracking Mechanism, power supply adjustor, and tariffs. Testimony filed in November 2011.
- On behalf of the North Dakota Public Service Commission (NDPSC), Case No. PU-10-657/PU-11-55: Northern States Power Company (NSP) 2011 and 2012 Request for Authority to Increase Electric Rates in North Dakota, April-October 2011. Project Manager and Testifying Witness. Led a team of consultants engaged to review NSP's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated NSP's proposed revenue requirement and testified before the NDPSC to proposed adjustments to the revenue requirements filed by the company in its application.
- On behalf of the City of Kansas City, Case No. HR-2011-0241: Veolia Energy Company (Veolia) 2011 and 2012 Request for Authority to Increase Electric Rates in Missouri, July-September 2011. Project Manager and Testifying Witness. Led a team of consultants engaged to review Veolia's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated Veolia's proposed revenue requirement and testified before the Missouri Public Service Commission to proposed adjustments to the revenue requirements filed by the company in its application.

- On behalf of the Attorney General of the State of Michigan (MIAG), Case No. U-16472: In the matter of the application of Detroit Edison for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority, February 2011-April 2014. Project Manager and Testifying Witness. Review of Advanced Metering Infrastructure program cost benefits and tariffs filed and testifying witness to same.
- On behalf of the CTPURA, Docket #10-02-13: Application of Aquarion Water Company to Amend its Rate Schedules, April-August 2010. Project Manager. Oversaw rate case analysis and assessment of company's proposed revenue requirement specifically related to cash working capital and test year expenses. Assisted with analysis of specific issues and preparation of Commission's recommended decision.
- On behalf of the Staff of the DEPSC, Docket No. 09-414: in the matter of the application of DPL for approval of modifications to its electric base rates, September 2009-May 2010. Project Manager. Oversaw rate case analysis and assessment of company's proposed revenue requirement. Assisted with analysis of specific issues and preparation of witness testimony.
- On behalf of the DCPSC, Formal Case No. 1076: In the Matter of the Application of Pepco for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service, July 2009-June 2010. Project Manager. Advised Commission Staff on the Company's and intervener's filings and testimony regarding revenue requirements, rate base, cost of service, rate design, bill stabilization, and depreciation.
- On behalf of the UTDPU, Docket No. 09-035-23: In the Matter of the Application of RMP for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, June 2009-February 2010. Project Manager and Testifying Witness. Verified the reasonableness of the revenue requirements as provided by the company in its application and testified before the Public Service Commission of Utah.
- On behalf of the Staff of the Maryland Public Service Commission (MDPSC), Case No. 9092/9093 (Phase II): Base Rate Proceeding for Pepco and DPL, December-March 2008. Project Manager and Testifying Witness. Provided rebuttal testimony on behalf of the Commission related to the reasonableness of the costs and charges of Pepco Holdings, Inc. Service Company.
- On behalf of the Ohio Hospital Association, Case No. 08-0917-EL-SSO: In the matter of the Application of American Electric Power of Ohio for authority to increase rates for distribution of electric service. Provided expertise to the association's attorney in negotiating rate with American Electric Power, September 2008-March 2009. Evaluated revenue and rate impact on member hospitals.

- On behalf of the MIAG, Case No U-15244: In the matter of the application of Detroit Edison (DetEd) for authority to increase its electric base rates, September 2007-October 2008. Project Manager and Testifying Witness. Testified regarding revenue requirements.
- On behalf of the Ohio Schools Council, Case No. 07-0551-EL-UNC: In the matter of the Application of FirstEnergy Ohio (and its operating companies Ohio Edison, Cleveland Electric, and Toledo Edison) for authority to increase rates for distribution service, modify certain accounting practices and for tariff approval, August 2007-April 2008. Project Manager. Hired by Ohio Schools Council's attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing FirstEnergy's application with respect to cost of service and rate design and the resulting impact on Council's member school systems' energy costs.
- On behalf of the MIAG, Case No. U-15245: In the matter of the application of Consumers Energy Company (CECO) for authority to increase its rates for the generation and distribution of electricity and for other relief, July 2007-April 2008. Project Manager and Testifying Witness. Provided expert testimony on partial and interim rate relief, CECO's decision to acquire Zeeland Power Company from Broadway Gen Funding, LLC. Provided testimony in permanent phase to reduce company's net operating income to more closely reflect the expected costs in 2008.
- On behalf of the City of Cincinnati, Case No. 06-0986-EL-UNC: In the matter of the Application of Duke Energy Ohio, Inc., to modify its market-based standard service offer, May-August 2007. Project Manager. Hired by City of Cincinnati's Water and Sewer District attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing the Company's proposal and impact on City's project energy costs.
- On behalf of the MIAG, Case No U-15190: In Base Rate Proceeding for CECO, March-September 2007. Project Manager. Reviewed the revenue decoupling proposal and supported the witness testimony.
- Technical consultant for the DCPSC in the matter of Pepco's request for a $50.4 million increase in base rates (Formal Case No. 1053), February 2007-June 2008. Project Manager. Provide technical expertise to Commission in evaluating the Company's rate case filing. Commission accepted adjustments which reduced the allowed increase by a significant percentage.
- On behalf of the Staff of the MDPSC, Case No. 9092: Base Rate Proceeding for Pepco, January-June 2007. Project Manager. Reviewed and analyzed company's base increase request and all pro formas, adjustments to test year revenue requirement and supported witness testimony. Commission approved less than 20% of Company's original request.
- On behalf of the Consumer Advocate of the Province of Nova Scotia, Case No. P-888: Base rate proceeding of Nova Scotia Power, December 2006-March 2007. Project Manager and Testifying Witness. Provided an evaluation of a

management audit of Nova Scotia Power and that report's usefulness to assess the Company's management performance and operational efficiency within the context of that proceeding.

- On behalf of the Staff of the DEPSC, Docket No. 06-284: in the matter of DPL's request for a $15M increase in gas base rates, October 2006-March 2007. Project Manager and Testifying Witness. Testified on several rate base and revenue requirement issues. Recommended Commission reduce proposed rate increase request to $8.4M (56%).
- On behalf of the Staff of the MDPSC, Case No. 9062: In the matter of the application of Chesapeake Utilities Corporation for authority to revise its rates and charges for gas service, May-October 2006. Project Manager. Managed a project team responsible for providing expert witness testimony in the areas of revenue requirements, rate base, cost of service, revenue allocation, rate design, revenue normalization, and cost of capital.
- On behalf of the MIAG, Case No. U-14547: In the matter of the application of CECO for authority to increase rates for the distribution of natural gas and for other relief, December 2005-April 2006. Expert Witness and Project Manager. Provided analysis, recommended adjustments, and filed testimony for the Attorney General on CECO's proposed increase to base rates.
- On behalf of the Illinois Citizens Utility Board, Cook County State's Attorney's Office and City of Chicago, Case: 05-0597, November 2005-May 2006. Project Manager and Testifying Witness. Provided analysis and recommended adjustments in the general rate increase of 20.1% or $320 million filed by Commonwealth Edison Company.
- On behalf of the MIAG, Case No. U-14347. Consumers Energy Company. April-September 2005. Project Manager. Supported the MIAG with analyses in preparation for testimony before the Commission.
- On behalf of the DCPSC, Formal Case No. 1032: In the Matter of the Investigation into Pepco's Distribution Service Rates, January-March 2005. Project Manager. Review and evaluation of Pepco compliance filings for class cost of service and revenue requirements for distribution service pursuant to a settlement approved in May 2002. Provided analysis and recommended adjustments to Staff on 23 designated issues and 13 Company proposed adjustments. Proceeding was settled in anticipation of a full rate case for rates to be effective August 8, 2007.
- On behalf of the DCPSC, Formal Case No. 1016: In the Matter of the Application of Washington Gas Light Company (WGL), District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service, June-December 2003. Project Manager and Consultant to Commissioners and Staff. Project Manager for the analysis of WGL's rate filings. Provided analysis and recommended adjustments to the DCPSC Staff on WGL's proposed increase to base rates. Advised the Commission during deliberations on party positions and possible recommendations.

- Consultant to Ameren UE. Conducted revenue requirement analysis in preparation of Missouri Public Service Commission compliance filing to un-bundle utility's rate tariffs. Prepared the filing requirements and all support schedules analysis to justify allocations of generation, transmission and distribution.
- Advised South Carolina State Senator on regulatory process for requesting States Public Service Commission for a comprehensive review of Duke Power Company's storm and restoration and right of way management. Reviewed and advised Senator of results of report finding.
- NYPSC, Case: 97-M-0567, Commission Staff. Litigated proceeding to determine the benefits of a proposed merger of LILCO/Brooklyn Union Gas. Analyzed proposed synergy savings.
- NYPSC, Case: 96-E-0132, Show Cause Proceeding Regarding Rate Relief for Ratepayers of LILCO, Commission Staff and Testifying Witness. Litigated proceeding where Staff proffered testimony containing a benchmark study showing that LILCO's operations and maintenance expenses were excessive compared to a peer group of 24 utilities. Panel testimony concerning the findings and conclusions resulting from the benchmark study.
- Before the Hawaii Public Utilities Commission, Docket No. 05-0075: In the matter of a proceeding to investigate Kauai Island Utility Coop's Proposed Revised Integrated Resource Plan and Demand Side Management Framework, June-November 2005. Project Manager. Managed a team of consultants responsible for evaluating the impact of the changes proposed by the Company.

Renewable Energy and Energy Conservation

- On behalf of the MIAG. Project Manager and Testifying Witness. Supported the MIAG with analysis and/or testimony regarding the Michigan Public Service Commission's 21st Century Energy Plan Report including various cases regarding Renewable Energy Plan (REP) costs and their associate plan reconciliations and Energy Optimization Plans (EOP). Analyzed cost methodologies used by the companies for adherence to approved processes and reasonable and prudent costs. Issues included calculation of transfer costs for inclusion in power supply recovery costs and adherence to specifications of Public Acts.
  - Case No. U-16655. Consumers Energy Company (CECO) reconciliation of its REP costs associated with the plan approved in Case No. U-15805 and Case No. U-16543. September 2012-January 2013.
  - Case No. U-16656. Detroit Edison Company (DetEd) reconciliation of its REP costs associated with the amended plan approved in Case No. U-16582. September 2012-March 2013. Project Manager and Testifying Witness.
  - Case No. U-16300. CECO for authority to reconcile its renewable energy plan costs associated with the plan approved in Case No. U-15805, November 2010-January 2011.

- Case No. U-16356. DetEd for authority to reconcile its REP costs associated with the plan approved in Case No. U-15806-RPS, October 2010-March 2011.

- Independent Third-Party Evaluation of Puget Sound Energy's (PSE) Conservation Incentive Mechanism (ECIM) under the co-direction of PSE and the Washington Utilities and Transportation Commission Staff, Phase I: July-October 2009; Phase II: October 2009-September 2010. Project Manager. Assess the extent to which the design and implementation of the incentive mechanism addressed key issues and objectives required by the Commission: accuracy of implementation in calculations of incentives or penalties, compliance with the conditions and requirements of the pilot program, proper use of the calculation methodology, and which assumptions or methods were used to calculate and verify the savings report.
- On behalf of the MIAG, Case No. U-15806/U-15890: In the matter of DetEd's and MichCon's compliance with Public Acts 286 and 296 regarding their REP and Energy Optimization Plan (EOP), March-June 2009. Project Manager and Testifying Witness. Reviewed the EOPs of both DetEd and MichCon and provided analysis of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.
- On behalf of the MIAG, Case No. U-15805/15889: In the matter of CECO to comply with Public Acts 286 and 295 regarding its REP and EOP, March-June 2009. Project Manager and Testifying Witness. Reviewed the EOP of CECO and provided analysis of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Restructuring and Unbundling

Mr. McGarry has developed the supporting analyses and regulatory filing requirements needed to support unbundling rates for utilities. This has included detailed studies where the company's plant-in-service and depreciation reserve was allocated to each unbundled function. He has assessed utility management actions to prepare the company for competition, including the processes and practices used by the utility to prepare to enter new markets and offer new services.

- Consultant to Illinois Power Company. Conducted mandated compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the Company's Controller.
- Consultant to Illinois Power Company. Prepared 2001 required update filing for the ILCC compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the Company's Controller.

Specialty Cases

- Case No. U-17429 on behalf of the Michigan Attorney General in the matter of the application of Consumers Energy Company for approval of a Certificate of Necessity for the Thetford Generating Plant pursuant to MCL 460.6s and for related accounting and ratemaking authorizations, September 2013-February 2014. Project Manager and Testifying Witness. Managed review and assessment of company and intervenor testimony regarding its need for generated power, the suitability of proposed new plant, reasonableness of the estimated costs and financing for the proposed plant, and the company's compliance with Commission directives related to the new plant. Testified to the best option for meeting power needs as well as the appropriateness of the contingency the Company has included in its estimated costs.

- Case No. U-17026 On behalf of the MIAG in the matter of the application of Indiana Michigan Power Company for a certificate of necessity pursuant to MCL 460.6s and related accounting authorizations, June-September 2012. Project Manager. Managed review of certificate of necessity, evaluation of company's prudency in obtaining alternative power supply options, and review of the company's implementation of and prudency in management of its nuclear plant Life Cycle Management project in comparison to industry standards.

Telecommunications

- Before the NYPSC, Case: 94-C-0657, Commission Staff. Proceeding to evaluate the compliance of NYNEX with Commission rules and orders related to operational support system costs to competitors. Part of staff panel to facilitate discussion between company and potential competitors (i.e., users of operational support systems) and report back to Commission.
- NYS PSC Opinion: 92-36 Operational Audit of New York Telephone Company Service Quality Standards Measurement Practices. A comprehensive operational audit to assess whether the Company had effective and accurate means to measure its performance for each of eleven service quality standards; whether New York Telephone accurately reported its performance on each of the eleven service quality standards; examined the internal controls the Company had in place to ensure that its performance for each of the service quality standards were accurately measured and reported; and reviewed the then current regulations and service quality standards against the Company's actual practices and performance to determine whether regulatory changes were necessary.

Testimony and Witness Preparation

Mr. McGarry has proffered and/or supported testimony in many jurisdictions. These proceedings have included testimony involving management decisions and prudence impacts, operations and maintenance expenses, capital investments, revenue requirements, project management, and others.

Testimony proffered

Before the Arizona Corporation Commission

- UNS Electric, Inc. - Docket No. E-04204A-12-0504
- Tucson Electric Power Company - Docket No. E-01933A-12-0291
- Arizona Public Service Company - Docket No. E-01345A-11-0224

Before the Delaware Public Service Commission

- Delmarva Power and Light Company - Docket No. 12-546
- Delmarva Power and Light Company - Docket No. 11-528
- Delmarva Power and Light Company - Docket No. 07-239F
- Delmarva Power and Light Company - Docket No. 06-284

Before the Georgia Public Service Commission
- Georgia Power Company - Docket No. 36989

Before the Illinois Commerce Commission
- Commonwealth Edison - Case No. 05-0597

Before Maine Public Utilities Commission
- Northern Utilities Inc. - Case No. 2008-151
- Northern Utilities Inc. - Case No. 2004-813

Before the Maryland Public Service Commission
- Pepco and Delmarva Power and Light Company - Case No. 9092/9093

Before the Michigan Public Service Commission
- Consumers Energy Company - Case No. U-17688
- Detroit Edison Company - Case No. U-17689
- Detroit Edison Company - Case No. U-17097-R
- Consumers Energy Company - Case No. U-17095-R
- Detroit Edison Company - Case No. U-17319
- Consumers Energy Company - Case No. U-17496
- Consumers Energy Company - Case No. U-17429
- Detroit Edison Company - Case No. U-16892-R
- Detroit Edison Company - Case No. U-17097
- Detroit Edison Company - Case No. U-15768
- Detroit Edison Company - Case No. U-16656
- Consumers Energy Company - Case No. U-16655
- Detroit Edison Company - Case No. U-16434-R
- Detroit Edison Company - Case No. U-16047-R
- Detroit Edison Company - Case No. U-16434
- Detroit Edison Company - Case No. U-16892
- Detroit Edison Company - Case No. U-16472
- Michigan Consolidated Gas Company - Case No. U-16407
- Detroit Edison Company - Case No. U-16356
- Consumers Energy Company - Case No. U-16300
- Detroit Edison Company - Case No. U-16047
- Detroit Edison Co. and Michigan Consolidated Gas - Case No. U-15806/U-15890
- Consumers Energy Company - Case No. U-15805/15889
- Detroit Edison Company - Case No. U-15677-R
- Consumers Energy Company - Case No. U-15675-R
- Consumers Energy Company - Case No. U-15415-R
- Consumers Energy Company - Case No. U-15245
- Detroit Edison Company - Case No. U-15244
- Michigan Gas Utilities, Corporation - Case No. U-15040

- Consumers Energy Company - Case No. U-15001
- Consumers Energy Company - Case No. U-14701-R
- Consumer Energy Company - Case No. U-14547

Before the Missouri Public Service Commission
- Veolia Energy Company - Case No. HR-2011-0241

Before the New York Public Service Commission
- Long Island Lighting Company - Case No. 96-E-0132
- Niagara Mohawk Power Company - Case No. 96-M-0858
- Jamaica Water - Case No. 91-W-0583
- New York State Electric & Gas Homer City Prudence Review - Case No. 88-E-115

Before the North Dakota Public Service Commission
- Northern States Power Company - Case Nos. PU-10-657 and PU-11-55

Before the Nova Scotia Utility and Review Board
- Nova Scotia Power - Case No. P-888

Before the Utah Division of Public Utilities
- Rocky Mountain Power - Docket No. 09-035-23

Training and Public Speaking

Mr. McGarry has presented topics before Commission staff groups, NARUC sub-committee groups, and as a program faculty member (2010 & 2011) for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, and price regulation theory, and cost trackers.

- National Association of Regulatory Utility Commissioners (NARUC). Presented, before the sub-committee on Accounting and Finance, a presentation on value of rate case audits. March 19, 2014
- NARUC. Presented, before the sub-committee on Accounting and Finance, a presentation on CAPEX trackers. March 28, 2012.
- Institute of Public Utilities, Michigan State University, East Lansing, MI. Presented a training session on Management Audits and Prudency Reviews to the attendees at the Institute of Public Utilities, Fall 2010 Advanced Regulatory Studies Program. September 27, 2011, and September 30, 2010.
- NARUC. Presented, before the sub-committee on Accounting and Finance, a presentation on service company costs and allocations to regulated entities. September 15, 2010.
- Special Case Study: Public Service Company of New Mexico, NM PRC Docket No. 10-00086-UT, June 2010. Worked with QSI Consulting, Inc. to conduct a training session for the New Mexico Public Service Commission Staff and to develop training materials for presentation to Staff on the basic elements of future test year proceedings, how those may differ from traditional rate cases, and how to apply and interpret the forecasting methodologies and modeling that will come

into play; and analyze the company's pending rate case and provide an analytic framework for Staff to apply to the forecasting issues in the case.

Professional Experience

Blue Ridge Consulting Services, Inc.: 2004-Present
President and CEO

Hawks, Giffels & Pullin, Inc.: 2003-2004
Vice President of East Coast Operations

Independent Consultant: 2001-2003

Denali Consulting, Inc.: 2000-2001
Senior Consultant

Navigant Consulting, Inc.: 1997-2000
Senior Consultant

New York State Department of Public Service: 1985-1997
Utility Operations Examiner

Seminole Electric Cooperative: 1983-1985
Rate Analyst II

Orange and Rockland Utilities: 1981-1983
Associate Rate Analyst

Education

Potsdam College, B.A., Economics, 1981
University at Buffalo School of Management, MBA, 1996

**CHEYENNE LIGHT, FUEL & POWER COMPANY;
BLACK HILLS NORTHWEST WYOMING GAS UTILITY COMPANY LLC, DBA BLACK HILLS ENERGY; AND BLACK HILLS POWER, INC.**

WY PSC DOCKETS: 20003-145-EA-15; 30005-208-GA-15; 30011-92-GA-15; and 20002-98-EA-15 (Record No. 14241)

Joint Application for Approval of Cost of Service Gas Agreement and Other Relief

REQUEST DATE: December 15, 2015

RESPONSE DATE: December 29, 2015

REQUESTING PARTY: Wyoming Public Service Commission Staff

CIR Data Request 3.6: Would Black Hills still offer the COSG program if the maximum gas supply for Wyoming gas and electric customers was capped at 10% of the overall gas supply program?

Response to CIR Data Request 3.6:

The 50% recommendation for reserves acquisition is based upon several factors. As described in the Aether Report, a meaningful volume commitment will bring greater economies of scale than a smaller program. The effort involved would not make sense to pursue if the COSG Program did not provide meaningful hedging protection to customers. From a market price perspective, indications are that the time is opportune. In a rising price environment customers are better protected with a higher percentage of hedging. Natural gas prices are currently at historical lows, but there are many indications prices will need to rise to encourage production growth to meet future demand increases.

The Company has not made any predetermination of a lower percentage of its general system natural gas portfolio as this program is focused on achieving the 50% long-term hedge based on analyses and the recommendations by Aether Advisors. Once BHUH knows the actual portfolio percentage commitments from the multiple states in which Black Hills Utilities have applied, then it will reevaluate the feasibility of continuing the COSG Program. There has to be a level of size and scale to the aggregate program to ensure that the administrative and other costs to maintain the program are not overly burdensome to the cost of producing gas.

Response provided by: **Ivan Vancas**

Attachments:

COST OF SERVICE GAS AGREEMENT

This COST OF SERVICE GAS AGREEMENT ("**COSG Agreement**"), dated September 15, 2015, is by and between BLACK HILLS UTILITY HOLDINGS, INC., a South Dakota corporation, ("**BHUH**") and the following (each a "**Utility**" and collectively the "**Utilities**"): BLACK HILLS POWER, INC., a South Dakota corporation; BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP, a Delaware limited partnership; BLACK HILLS/COLORADO GAS UTILITY COMPANY, LP, a Delaware limited partnership; BLACK HILLS/IOWA GAS UTILITY COMPANY, LLC, a Delaware limited liability company; BLACK HILLS/KANSAS GAS UTILITY COMPANY, LLC, a Kansas limited liability company; BLACK HILLS/NEBRASKA GAS UTILITY COMPANY, LLC, a Delaware limited liability company; BLACK HILLS NORTHWEST WYOMING GAS UTILITY COMPANY, LLC, a Wyoming limited liability company; and CHEYENNE LIGHT, FUEL AND POWER COMPANY, a Wyoming corporation. BHUH and Utilities are referred to individually as a "**Party**" and collectively as the "**Parties.**"

RECITALS

A. BHUH purchases natural gas for, or on behalf of, each Utility.

B. Each Utility desires for BHUH to cause physical reserves of natural gas to be acquired and developed pursuant to this COSG Agreement to (i) reduce volatility in the price for natural gas, (ii) hedge against long-term increases in the market price for natural gas, and (iii) reduce long-term costs to its customers by using a cost-based, rather than market-based, approach to meeting a portion of its natural gas needs.

NOW, THEREFORE, the Parties agree as follows:

ARTICLE 1 - DEFINITIONS

The following terms shall have the following meanings:

"**Accounting Monitor**" means an independent, third-party certified public accountant.

"**Acquisition Criteria**" means the criteria set forth in attached Exhibit A.

"**Actual ROE**" means the percentage obtained by dividing Net Income by Invested Equity.

"**Affiliated Utility**" means each Utility for which BHUH acts as agent when buying Gas, namely Black Hills Power, Inc., Black Hills Northwest Wyoming Gas Utility Company, LLC, and Cheyenne Light, Fuel and Power Company.

"**Allowed Cost of Debt**" means the weighted average of the following: (i) the cost of long-term debt, if any, of COSGCO, and (ii) for the balance of forty percent (40%) of Investment Base, the weighted average of Black Hills Corporation's cost of long-term debt.

"**Allowed ROE**" means the average of the annual return on equity in all gas and electric utility rate cases for the calendar year, as subsequently reported by Regulatory Research Associates, *provided* that if less than twenty (20) gas and electric utility rate cases are reported for a calendar year, then Allowed ROE for that calendar year shall equal the average of (i) the average of the annual return on equity in all gas and electric utility rate cases for that calendar year, and (ii) the average of the annual return on equity in all gas and electric utility rate cases for the prior calendar year, all as reported by Regulatory Research Associates.

"**BHUH**" is defined in the introductory paragraph of this COSG Agreement.

"**COSG Agreement**" is defined in the introductory paragraph of this COSG Agreement.

"**COSG Cost Forecast**" is defined in Section 4.2(xiv).

"**COSGCO**" means wholly-owned subsidiary of BHUH that is operated for the purpose of implementing this COSG Agreement.

"**COSGCO Gas**" means COSGCO's Gas produced from the Properties.

"**COSGCO OpEx**" means COSGCO's expenses, calculated in accordance with GAAP, including without limitation the costs of management, attorneys, consultants, operating expenses, fees and charges paid to the operator, gathering, transportation, compression, line loss and unaccounted for gas costs, minimum daily quantity penalties, processing, marketing, royalties, depreciation, amortization and depletion (including accruals for future plugging, abandonment, and other anticipated asset retirement expenses calculated using engineering estimates and GAAP), Taxes, and direct charges from BHUH and its affiliates for time spent providing services for the benefit of COSGCO, *provided* that (i) COSGCO OpEx shall include BHUH's costs for the Monitors, (ii) depletion shall be calculated on a unit of production basis using the "full cost method" but limited to proved developed producing reserves, (iii) depletion shall include the costs to identify and evaluate potential properties that do not become Properties under this COSG Agreement, and (iv) COSGCO's actual interest expense shall be replaced with an amount equal to the Allowed Cost of Debt multiplied by Investment Base multiplied by forty percent (40%).

"**COSGCO Revenue**" means the net proceeds received by COSGCO from the sale of Hydrocarbons produced from the Properties.

"**Cost of Capital**" shall be an imputed weighted average consisting of forty percent (40%) Allowed Cost of Debt and sixty percent (60%) Allowed ROE.

"**Drilling Plan**" means the plan approved under Section 4.3 or Section 4.4, as applicable, to drill wells on a Property.

"**Drilling Plan Criterion**" means the criterion set forth in attached Exhibit B.

"**Drilling Plan II**" means a plan approved under Section 4.5 to drill wells on a Property after the twentieth (20th) anniversary of the First Acquisition Date.

"**Dth**" means dekatherm.

"**Early Termination Amount**" is defined in Section 6.4.

"**Effective Date**" means the date the condition subsequent in Section 8.1 is satisfied or, if not satisfied, the date this COSG Agreement is deemed effective pursuant to Section 8.1.

"**First Acquisition Date**" means the date the first Property acquisition closes.

"**Five-Year Anniversary**" means the fifth (5th), tenth (10th), and fifteenth (15th) anniversaries of the First Acquisition Date.

"**Force Majeure Event**" is defined in Section 9.4.

"**Forecast Period**" means the six (6) months in each calendar year from (i) January 1 to June 30, and (ii) July 1 to December 31.

"**GAAP**" means generally accepted accounting principles as recognized by the American Institute of Certified Public Accountants, as in effect from time to time, consistently applied and maintained on a consistent basis by BHUH throughout the applicable period and consistent with BHUH's prior financial practice.

"**Gas**" means any mixture of gaseous Hydrocarbons or of Hydrocarbons and other gasses, in a gaseous state, consisting primarily of methane, and excluding condensate and NGLs.

"**Hedge Cost**" is defined in Section 5.1(ii).

"**Hedge Credit**" is defined in Section 5.1(i).

"**Hedge Forecast Amounts**" is defined in Section 5.2.

"**Hedge Quantity**" is defined in Section 3.3.

"**Hedge Target**" means, for each Utility, fifty percent (50%) of its anticipated annual natural gas demand, *provided* that anticipated annual natural gas demand shall be (i) for a gas utility, its weather-normalized annual firm demand, (ii) for Black Hills Power, Inc., 600,000 Dths per year, which shall increase annually by 1.25%, (iii) for Black Hills/Colorado Electric Utility Company, LP, 10,500,000 Dth per year, which shall increase annually by 0.87%, and (iv) for Cheyenne Light, Fuel and Power Company (elec.), 400,000 Dths per year, which shall increase annually by 1.25%.

"**Hedge Year-End Amount**" is defined in Section 5.3.

"**Hydrocarbon Monitor**" means an independent third party with substantial experience evaluating oil and gas transactions.

"**Hydrocarbons**" means hydrocarbons, in either liquid or gaseous form, including Gas, condensate, NGLs, and oil.

"**Invested Equity**" means the product of Investment Base and sixty percent (60%).

"**Investment Base**" means the capitalized costs to identify, acquire and develop the Properties, including lease acquisition costs, capital investments, drilling, completion and equipping costs, and compression and gas gathering and processing capital costs, reduced by accumulated depletion, depreciation, amortization, and net accumulated deferred taxes, *provided* that (i) for purposes of calculating Investment Base in connection with Hedge Forecast Amounts under Section 5.2 and the Hedge Year-End Amount under Section 5.3, if there are no capitalized costs at the beginning of the relevant period, then the period for calculating Investment Base shall commence when capitalized costs are incurred,[1] and (ii) the capitalized costs to identify and acquire a Property shall be allocated to proved developed producing reserves at the time of the acquisition and to proved undeveloped reserves developed under the Drilling Plan for the Property prior to the Five-Year Anniversary immediately following the Property's acquisition.

"**Long-Term Market Price Forecast**" shall mean the following, in nominal dollars:

(i) for Gas, the average of the most recent long-term "base case" Gas price forecast published by Ventyx and the long-term "reference case" Gas price forecast published by the U.S. Energy Information Administration in its most recent "Annual Energy Outlook";

(ii) for NGLs, a commercially reasonable price forecast based on available public information;

(iii) for all other Hydrocarbons (excluding Gas and NGLs), the average of the most recent long-term "base case" crude oil price forecast published by Ventyx and the long-term "reference case" crude oil price forecast published by the U.S. Energy Information Administration in its most recent "Annual Energy Outlook,"

Provided that (a) the locational basis of each forecast shall be adjusted to correspond with the respective delivery point for COSGCO's Hydrocarbons, (b) inflation shall be forecast using the inflation percentage used by the U.S. Energy Information Administration in its most recent "Annual Energy Outlook," and (c) if a forecast does not extend through the end of the period covered by the applicable Reserve Report, then the forecast price for the last year of that forecast shall be escalated annually by the aforementioned inflation percentage.

"**Monitors**" means the Accounting Monitor and the Hydrocarbon Monitor.

"**Net Cap. Costs**" is defined in Section 6.4.

[1] For example only, if COSGCO paid $50 million to acquire its first Property on March 15, then Investment Base for purposes of calculating the Hedge Year-End Amount pursuant to Section 5.3 for that calendar year would be the average of COSGCO's capitalized costs on March 15, March 31, and the end of each subsequent calendar month in that calendar year.

"**Net Income**" means COSGCO Revenue minus COSGCO OpEx, calculated in accordance with GAAP.

"**Net Op. Costs**" is defined in Section 6.4.

"**NGLs**" means those liquid Hydrocarbons, excluding condensate, obtained by processing gas.

"**Non-Participating Utility**" means, with respect to any Property, a Utility (i) whose PUC determines pursuant to Section 4.3 that the Property's proposed acquisition does not satisfy the Acquisition Criteria, (ii) whose PUC determines pursuant to Section 4.4 that an updated Drilling Plan does not satisfy the Drilling Plan Criterion, or (iii) that either determines it does not want to participate in further development of the Properties after the twentieth (20th) anniversary of the First Acquisition Date or whose PUC determines pursuant to Section 4.5 that a Drilling Plan II does not satisfy the Drilling Plan Criterion.

"**Party**" and "**Parties**" are defined in the introductory paragraph of this COSG Agreement.

"**Percentage Share**" means, for each Utility, its then-applicable Hedge Target divided by the Utilities' then-applicable aggregate Hedge Target.

"**PGA/GCA/ECA Filing**" means, with respect to each Utility, its purchased gas adjustment, gas cost adjustment or energy cost adjustment filing.

"**Property**" and "**Properties**" means any property approved pursuant to Section 4.3 in which COSGCO acquires interests, or the right to earn interests through drilling.

"**Proposed Drilling Program**" is defined in Section 4.2(ii).

"**PUC**" means the Colorado Public Utilities Commission with respect to Black Hills/Colorado Gas Utility Company, LP and Black Hills/Colorado Electric Utility Company, LP; Iowa Utilities Board with respect to Black Hills/Iowa Gas Utility Company, LLC; Kansas Corporation Commission with respect to Black Hills/Kansas Gas Utility Company, LLC; Nebraska Public Service Commission with respect to Black Hills/Nebraska Gas Utility Company, LLC; South Dakota Public Utilities Commission with respect to Black Hills Power, Inc.; and Wyoming Public Service Commission with respect to Black Hills Power, Inc., Cheyenne Light, Fuel and Power Company and Black Hills Northwest Wyoming Gas Utility Company, LLC.

"**Reserve Report**" is defined in Section 4.2(xii).

"**T**" means the highest marginal statutory federal income tax rate applicable to corporations combined with applicable state statutory income tax rates, in effect for the year in question.

"**Taxes**" means all taxes, charges, fees, duties, levies, or other assessments, however, denominated, imposed by any federal, state, or local government or any agency or political subdivision of any such government, including, without limiting the generality of the foregoing, income or profit, gross receipts, net proceeds, ad valorem, real and personal property (tangible and intangible), possessory interest, sales, use, franchise, excise, value added, stamp, leasing, lease, business license, user, transfer, fuel, environmental, excess profits, occupational, interest equalization, windfall profits, severance and employees' income withholding, workers' compensation, Pension Benefits Guaranty Corporation premiums, unemployment and Social Security taxes, and other obligations of the same or of a similar nature to any of the foregoing (all including any interest, penalties or additions to tax related thereto imposed by any taxing authority).

"**Term**" is defined in Section 6.1.

"**Utility**" and "**Utilities**" are defined in the introductory paragraph of this COSG Agreement, *provided* that notwithstanding anything to the contrary (i) with respect to Black Hills Power, Inc., this COSG Agreement only pertains to its utility operations in South Dakota and Wyoming, (ii) the gas and electric utility operations of Cheyenne Light, Fuel and Power Company shall each be considered a separate Utility, and (iii) Utility and Utilities does not include any Utility whose PUC has not approved this COSG Agreement in full and without modification in an order satisfactory to BHUH and the Utility.

ARTICLE 2 - MONITORS

Section 2.1 Accounting Monitor; Hydrocarbon Monitor. BHUH shall retain the Accounting Monitor and Hydrocarbon Monitor, each mutually agreeable to BHUH and the PUCs. The Accounting Monitor shall prepare assurance reports regarding the accuracy of BHUH's calculations under this COSG Agreement pursuant to Section 5.5. The Hydrocarbon Monitor shall assess the following: (i) whether each proposed acquisition satisfies the Acquisition Criteria pursuant to Section 4.3; (ii) whether each Drilling Plan and Drilling Plan II satisfies the Drilling Plan Criterion pursuant to Section 4.4 and Section 4.5, respectively; and (iii) whether COSGCO's reserves in the annual report described in Section 5.5 were calculated in accordance with standard industry practice.

Section 2.2 Communications. The Monitors shall be available to BHUH, the Utilities, and the PUCs. BHUH, the Utilities, and the PUCs shall be given advance notice, reasonable under the circumstances, of and afforded the opportunity to join any discussions with the Monitors and shall be copied on all written communications to/from the Monitors.

Section 2.3 Records; Confidentiality. BHUH and COSGCO's books, accounts, and records regarding the Properties and this COSG Agreement shall be available to the Monitors, each Utility, and each PUC for inspection at any reasonable time with prior notice. The Monitors and the PUCs shall each not disclose to any third party any information or other communications to or from BHUH, COSGCO, one or both of the Monitors, or any PUC(s) without the prior written consent of BHUH and the PUCs.

ARTICLE 3 - GAS PURCHASE

Section 3.1 Gas Purchase. In accordance with BHUH's role as purchaser of Gas for, or on behalf of, each Utility pursuant to prior PUC precedent and rules, during the Term each

Utility shall continue to reimburse BHUH for the costs BHUH incurs purchasing Gas on the market for, or on behalf of, the Utility, including the Utility's Hedge Quantity, *provided* that BHUH shall not purchase, directly or indirectly, Gas produced from the Properties unless mutually agreeable to all Parties pursuant to a written addendum to this COSG Agreement executed by all Parties. In addition, during the Term each Utility shall receive any credits and incur any costs required under ARTICLE 5.

Section 3.2 Hedge Target. On or before November 1 of each year, each Utility shall provide BHUH with its Hedge Target for each remaining year in the Term. Each Utility's Hedge Target and Percentage Share for 2016 are set forth in attached Exhibit C. Notwithstanding anything to the contrary in this COSG Agreement, a Utility's Hedge Target shall not decrease in any year unless such decrease can be accommodated pursuant to Section 3.4.

Section 3.3 Hedge Quantity. Each Utility's "**Hedge Quantity**" in each calendar month during the Term shall be a quantity of Gas equal to the Utility's Percentage Share multiplied by the quantity of COSGCO Gas produced during that calendar month, *provided* that the Utility's Hedge Quantity shall not exceed its Hedge Target unless (i) the Utility experiences a decrease in its Hedge Target as set forth in Section 3.4, in which case its Hedge Quantity may temporarily exceed its Hedge Target while BHUH seeks to accommodate such decrease pursuant to Section 3.4, or (ii) the Properties produce more Gas than anticipated by the Drilling Plans, in which case the Utility's Hedge Quantity may temporarily exceed its Hedge Target while one or more of the Drilling Plans is adjusted to decrease production from the Properties.

Section 3.4 Decrease to a Utility's Hedge Target. If a Utility experiences, after adjusting for weather normalization, a ten percent (10%) or more decrease to its anticipated natural gas demand that was used in calculating its Hedge Target and the Utility reasonably expects such reduced demand will continue, then BHUH shall take all reasonable steps to accommodate such decrease as soon as reasonably practicable, including the following:

(i) Adjusting the Drilling Plan(s) as soon as reasonably practicable to decrease production from the Properties to account for such decrease; and/or

(ii) Decreasing the Utility's Percentage Share to account for such decrease and increasing the other Utilities' Percentage Shares but only (i) with each of the other Utilities' prior consent, and (ii) to the extent that each of the other Utilities' resulting Hedge Quantity does not exceed its Hedge Target,

Provided that until BHUH is able to accommodate such a change, this COSG Agreement shall continue to apply to the Utility's full Hedge Quantity before such reduction in demand and the Utility shall accept any credits and incur any costs required under ARTICLE 5 calculated using the Utility's full Hedge Quantity before such reduction in demand.

ARTICLE 4 - PROPERTIES

Section 4.1 Property Acquisition and Development. For the twenty (20) years following the First Acquisition Date, BHUH shall cause COSGCO to acquire interests, or the right to earn interests through drilling, in one or more properties and to develop each Property in accordance with its Drilling Plan to increase and maintain COSGCO Gas production up to the

Utilities' aggregate Hedge Target subject to the processes and PUC oversight described in this ARTICLE 4 and to the extent commercially feasible. BHUH shall cause COSGCO to endeavor to increase COSGCO Gas production up to the Utilities' aggregate Hedge Target as soon as practical after the Effective Date and then to maintain COSGCO Gas production at the Utilities' aggregate Hedge Target until the twentieth (20th) anniversary of the First Acquisition Date, *provided* that, notwithstanding anything to the contrary in this COSG Agreement, this obligation shall be subject to the following:

(i) BHUH's determination, in its sole discretion, regarding the maximum capital expenditure to be made with respect to any proposed acquisition, the availability of property(ies) that satisfy the Acquisition Criteria, and the annual schedule for capital expenditures by COSGCO on acquisition and development; and

(ii) The processes and PUC oversight described this ARTICLE 4.

BHUH shall cause COSGCO to limit its business activities to identifying and evaluating potential Property acquisitions; acquiring, developing and operating the Properties; marketing and selling Hydrocarbons produced from the Properties; and conducting other activities related to operating the Properties. For the avoidance of doubt, except as expressly provided this ARTICLE 4, decisions regarding the development and operation of the Properties, including without limitation well locations, shall be made solely by COSGCO as directed by BHUH.

Section 4.2 <u>Acquisition Information</u>. BHUH shall provide the Hydrocarbon Monitor with the following information concerning each proposed COSGCO acquisition that BHUH wants to become a Property under this COSG Agreement:

(i) Price and terms of the proposed acquisition by COSGCO, including any joint operating agreement(s) to which COSGCO would become bound;

(ii) A plan to drill wells on a schedule intended, to the extent commercially feasible, to develop and maintain reasonably stable production from the property for a period of at least five (5) years ("**Proposed Drilling Program**"), *provided* that proposed acquisitions that are fully developed or that have a Proposed Drilling Program less than five (5) years in length can become Properties under this COSG Agreement if the Acquisition Criteria are satisfied;

(iii) Gross working interest and net revenue interest to be acquired or earned by COSGCO in existing wells, if any, and wells to be developed through execution of the Proposed Drilling Program;

(iv) Historical production from and remaining reserves of existing wells;

(v) Forecast reserves for wells to be developed through execution of the Proposed Drilling Program;

(vi) Forecast production for existing wells and wells to be developed through execution of the Proposed Drilling Program, showing aggregate production per year;

(vii) A summary of geologic and geophysical data;

(viii) Historical exploration, drilling and operating costs (including gathering and processing costs) of existing wells;

(ix) Forecast operating costs (including gathering and processing costs) of existing wells;

(x) Forecast capital and operating costs (including gathering and processing costs) for future wells;

(xi) Estimated production tax for existing wells and to be developed through execution of the Proposed Drilling Program;

(xii) A third-party engineering report (the "**Reserve Report**") assessing, using the then-current Long-Term Market Price Forecast, (1) the proved reserves (including without limitation proved undeveloped reserves) and any probable reserves to be developed through execution of the Proposed Drilling Program, (2) the forecast production for existing wells and wells to be developed through execution of the Proposed Drilling Program, and (3) the estimated cost to develop the proved reserves through execution of the Proposed Drilling Program and the projected costs per Dth for existing and to-be-developed reserves as produced;

(xiii) Then-current Long-Term Market Price Forecast;

(xiv) The "**COSG Cost Forecast**," which means, for each year of the Reserve Report, the forecast Gas cost calculated in nominal dollars pursuant to the following formula:

*COSG Cost Forecast = [COSGCO OpEx + (Cost of Capital * Investment Base)] - Liquids Revenue*

Provided that (i) "Liquids Revenue" means the money COSGCO is anticipated to receive from the sale of all Hydrocarbons other than Gas, and (ii) the then-current Long-Term Market Price Forecast and the Proposed Drilling Program, Drilling Plan or Drilling Plan II, as applicable, shall be used in calculating the COSG Cost Forecast;

(xv) Description of any material lease, title, and legal issues known by COSGCO concerning the proposed acquisition;

(xvi) A consultant's report describing environmental and regulatory permits and permit compliance for the existing wells and infrastructure related to the proposed acquisition; and

(xvii) Other data as BHUH may deem to be appropriate to an evaluation of the proposed acquisition.

Section 4.3 Acquisition Oversight. Within ten (10) calendar days following receipt of all the information described in Section 4.2, the Hydrocarbon Monitor shall issue a written report to BHUH, the Utilities, and the PUCs regarding whether the proposed acquisition satisfies the Acquisition Criteria.

If the Hydrocarbon Monitor determines that the proposed acquisition does not satisfy the Acquisition Criteria, then the proposed acquisition shall not be deemed a Property under this COSG Agreement, *provided* such a determination shall not preclude BHUH from subsequently seeking approval under this Section 4.3 for the same proposed acquisition.

If the Hydrocarbon Monitor determines that the proposed acquisition satisfies the Acquisition Criteria and no PUC reaches a contrary determination in a formal, adjudicative proceeding concluded within sixty (60) calendar days after receipt of the Hydrocarbon Monitor's report, then the following shall occur upon the closing of the acquisition: the proposed acquisition shall be deemed a Property under the terms of this COSG Agreement, the Proposed Drilling Program shall become the Drilling Plan for the Property, and BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with the Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action.

If the Hydrocarbon Monitor determines that the proposed acquisition satisfies the Acquisition Criteria but one or more PUCs reach a contrary determination in a formal, adjudicative proceeding concluded within sixty (60) calendar days after receipt of the Hydrocarbon Monitor's report, then, if BHUH directs COSGCO to move forward with the proposed acquisition, the following shall occur upon the closing of the acquisition:

(i) The proposed acquisition shall be deemed a Property under the terms of this COSG Agreement, the Proposed Drilling Program shall become the Drilling Plan for the Property, and BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with the Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action, *provided* that if BHUH determines that the Proposed Drilling Program needs to be modified to account for the non-participation of a Non-Participating Utility in the Property, then (1) BHUH shall first make such modifications to the Proposed Drilling Program, and (2) the proposed acquisition shall not become a Property unless the Hydrocarbon Monitor issues a written report concluding that the proposed acquisition (with the modified Proposed Drilling Program) satisfies the Acquisition Criteria, in which case the modified Proposed Drilling Program shall become the Drilling Plan for the Property, and BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with that Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action;

(ii) Any capital and operating expenses incurred by COSGCO to acquire, develop and operate the Property and any production from the Property shall not be used when calculating the Hedge Quantity and any credits and costs under ARTICLE 5 for a Non-Participating Utility, and a Non-Participating Utility shall neither receive any credits nor incur any costs under ARTICLE 5 with respect to the Property; and

(iii) A Non-Participating Utility and its PUC shall have no rights or obligations with respect to the Property under Section 4.4.

Section 4.4 Five-Year Drilling Plan Review. No later than seventy (70) calendar days before each Five-Year Anniversary, BHUH shall provide the Hydrocarbon Monitor with the information described in Section 4.2(iii)-(xiv) for each Property, the Utilities' aggregate Hedge Target for each remaining year in the twenty (20) year period following the First Acquisition Date, and an updated Drilling Plan for each Property for such period. BHUH may seek approval for an updated Drilling Plan for any Property at any other time by providing the Hydrocarbon Monitor with the information described in Section 4.2(iii)-(xiv) for the Property, the Utilities' aggregate Hedge Target for each remaining year in the twenty (20) year period following the First Acquisition Date, and an updated Drilling Plan the Property for such period.

Within ten (10) calendar days following receipt of said information, the Hydrocarbon Monitor shall issue a written report to BHUH, the Utilities, and the PUCs regarding whether the updated Drilling Plan(s) satisfies the Drilling Plan Criterion.

If the Hydrocarbon Monitor determines that an updated Drilling Plan does not satisfy the Drilling Plan Criterion, then BHUH shall cause COSGCO to not participate in the drilling of any new production wells on the Property until an updated Drilling Plan has been approved under this Section 4.4.

If the Hydrocarbon Monitor determines that an updated Drilling Plan satisfies the Drilling Plan Criterion and no PUC reaches a contrary determination in a formal, adjudicative proceeding concluded within sixty (60) calendar days after receipt of the Hydrocarbon Monitor's report, then BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with the Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action.

If the Hydrocarbon Monitor determines that the updated Drilling Plan satisfies the Drilling Plan Criterion but one or more PUCs reach a contrary determination in a formal, adjudicative proceeding concluded within sixty (60) calendar days after receipt of the Hydrocarbon Monitor's report, then the following shall occur:

(i) BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with the Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action, *provided* that if BHUH determines that the Drilling Plan needs to be modified to account for the non-participation of a Non-Participating Utility in the updated Drilling Plan, then (1) BHUH shall first make such modifications to the updated Drilling Plan, and (2) BHUH shall cause COSGCO to not develop the Property in accordance with that modified Drilling Plan unless the Hydrocarbon Monitor issues a written report concluding that the modified Drilling Plan satisfies the Drilling Plan Criterion, in which case BHUH shall cause COSGCO to develop the Property until the next Five-Year Anniversary in accordance with that Drilling Plan, unless adjusted pursuant to Section 3.3 or Section 3.4, and without further PUC action;

(ii) Any capital and operating expenses incurred by COSGCO to develop and operate additional wells on the Property after the effective date of the updated Drilling Plan and any production from such wells shall not be used when calculating the Hedge Quantity and the credits and costs under ARTICLE 5 for a Non-Participating Utility; and

(iii) A Non-Participating Utility and its PUC shall have no further rights or obligations with respect to the Property under this Section 4.4.

Section 4.5 Drilling Plan II. Notwithstanding anything to the contrary in this COSG Agreement, following the twentieth (20th) anniversary of the First Acquisition Date COSGCO shall not continue drilling new production wells on the Properties except as provided in this Section 4.5, *provided* that BHUH shall cause COSGCO to continue producing Hydrocarbons from the wells COSGCO acquired or drilled prior to such twentieth (20th) anniversary and each Utility shall continue to receive any credits and incur any costs required under ARTICLE 5 until the expiration or early termination of this COSG Agreement. If BHUH anticipates that opportunities to further develop one or more of the Properties may exist on the twentieth (20th) anniversary of the First Acquisition Date and one or more Utilities (but with respect to any Property with further development opportunities, excluding any Non-Participating Utility) desire for BHUH to cause COSGCO to participate in such opportunities, then BHUH shall provide the Hydrocarbon Monitor with Drilling Plan II for each such Property and the information described in Section 4.2(iii)-(xiv) for each such Property no later than seventy (70) calendar days before the twentieth (20th) anniversary of the First Acquisition Date. Drilling Plan II(s) shall then be subject to the review process, criterion, and other terms set forth in the second through fifth paragraphs of Section 4.4.

Section 4.6 Opportunity for Non-Participating Utilities to Participate in Subsequent Drilling Plans. Notwithstanding anything to the contrary in Section 4.3 and Section 4.4, BHUH may propose that a Non-Participating Utility participate in new production wells to be drilled pursuant to an updated Drilling Plan for the Property in which the Non-Participating Utility is not participating, *provided* that in such situation, the following provisions shall supplement the review of the updated Drilling Plan under Section 4.4:

(i) In addition to providing the information identified in Section 4.4, BHUH shall provide the Hydrocarbon Monitor with information describing why and/or how the proposed participation of the Non-Participating Utility in such updated Drilling Plan is not anticipated to be detrimental to the other Utilities participating in the Property;

(ii) If the Hydrocarbon Monitor, in addition to determining that the updated Drilling Plan satisfies the Drilling Plan Criterion, concurs with BHUH in the written report called for under Section 4.4, then the updated Drilling Plan shall be subject to the fourth and fifth paragraphs of Section 4.4 and

1) If either the PUC for the Non-Participating Utility reaches a contrary determination in a formal, adjudicative proceeding concluded within sixty (60) calendar days after receipt of the Hydrocarbon Monitor's report or one or more of the PUCs for the other Utilities participating in the Property objects within such sixty (60) calendar day period to the proposed participation of the

Non-Participating Utility, then the Non-Participating Utility shall remain a Non-Participating Utility with respect to new production wells drilled pursuant to the updated Drilling Plan; but

2) If the PUC for the Non-Participating Utility does not reach a contrary determination in a formal, adjudicative proceeding concluded with such sixty (60) calendar day period and none of the PUCs for the other Utilities participating in the Property objects within such sixty (60) calendar day period, then the Non-Participating Utility shall participate in new production wells drilled pursuant to the updated Drilling Plan, any capital and operating expenses incurred by COSGCO to develop and operate additional wells on the Property after the effective date of the updated Drilling Plan and any production from such wells shall be used when calculating the Hedge Quantity and the credits and costs under ARTICLE 5 for the Non-Participating Utility, and the Non-Participating Utility and its PUC shall have further rights and obligations with respect to the Property under Section 4.4.

ARTICLE 5 - HEDGE SETTLEMENT

Section 5.1 Hedge Settlement. After the end of each calendar month, BHUH shall calculate a Hedge Credit pursuant to Section 5.1(i) or a Hedge Cost pursuant to Section 5.1(ii), as applicable.[2]

(i) Hedge Credit. If Actual ROE for a calendar month is more than one hundred (100) basis points greater than Allowed ROE, then a "**Hedge Credit**" for such calendar month shall be calculated pursuant to the following formula:

$$\textit{Hedge Credit} = -(\textit{Net Income} - ((\textit{Allowed ROE} + 100 \textit{ basis points}) * \textit{Invested Equity})) * \frac{1}{(1-T)}$$

Each Utility's Percentage Share of the Hedge Credit shall be credited against the amount the Utility owes to BHUH for all Gas that BHUH purchased on the market for, or on behalf of, the Utility in that calendar month, *provided* that BHUH shall instead pay each Affiliated Utility its Percentage Share of the Hedge Credit within thirty (30) days following the end of that calendar month.

(ii) Hedge Cost. If Actual ROE for a calendar month is more than one hundred (100) basis points less than Allowed ROE, then a "**Hedge Cost**" for such calendar month shall be calculated pursuant to the following formula:

$$\textit{Hedge Cost} = -(\textit{Net Income} - ((\textit{Allowed ROE} - 100 \textit{ basis points}) * \textit{Invested Equity})) * \frac{1}{(1-T)}$$

[2] Sample calculations of a Hedge Credit and Hedge Cost are shown in attached Exhibit D for illustrative purposes only.

Each Utility's Percentage Share of the Hedge Cost shall be included as a cost in the amount the Utility owes to BHUH for all Gas that BHUH purchased on the market for, or on behalf of, the Utility in that calendar month, *provided* that each Affiliated Utility shall instead pay BHUH its Percentage Share of the Hedge Cost within thirty (30) days following the end of that calendar month.

Section 5.2 Utility Hedge Forecast. To establish reasonably accurate rates in advance for the Utilities' customers, BHUH shall do the following before the start of each Forecast Period: (i) forecast Actual ROE for each calendar month of that Forecast Period using the average of the forecast Investment Base for each calendar month in that Forecast Period; and (ii) forecast a Hedge Credit calculated pursuant to Section 5.1(i) or a Hedge Cost calculated pursuant to Section 5.1(ii), as applicable, for each calendar month of that Forecast Period (collectively, the "**Hedge Forecast Amounts**") using the most recent Allowed ROE. To help minimize annual reconciliations under Section 5.3, the Hedge Forecast Amounts may also include an adjustment to reflect anticipated differences between the Hedge Forecast Amounts for an unreconciled Forecast Period(s) and COSGCO's actual results to date in that calendar year. Each Utility shall incorporate its Percentage Share of the Hedge Forecast Amounts into its rates for the Forecast Period in accordance with its approved tariffs and adjustment mechanisms.

Notwithstanding anything to the contrary in the immediately preceding paragraph, (i) until the First Acquisition Date, the Hedge Forecast Amounts shall be zero, and (ii) concurrent with the closing of the acquisition of any Property, BHUH shall update the Hedge Forecast Amounts for the remainder of the then-current Forecast Period and each Utility shall incorporate its Percentage Share of the updated Hedge Forecast Amounts into its rates for the Forecast Period in accordance with its approved tariffs and adjustment mechanisms.

Section 5.3 Annual Hedge Reconciliation. To ensure that the Utilities and their customers are receiving the actual benefits or paying the actual costs of this COSG Agreement and to incorporate the actual Allowed ROE for each calendar year, BHUH shall do the following no later than ninety (90) calendar days after the end of each calendar year: (i) calculate Actual ROE for that prior calendar year; (ii) calculate the actual Hedge Credit or the actual Hedge Cost, as applicable, for that prior calendar year (the "**Hedge Year-End Amount**") using the Allowed ROE for that prior calendar year and the trailing thirteen (13) calendar month average of Investment Base; (iii) reconcile the Hedge Year-End Amount with the aggregate Hedge Credits and Hedge Costs credited or billed to each Utility pursuant to Section 5.1 for that prior calendar year, including crediting each Utility its Percentage Share of any additional Hedge Credit amount and billing each Utility its Percentage Share of any additional Hedge Cost amounts consistent with Section 5.1; and (iv) reconcile the Hedge Year-End Amount with the Hedge Forecast Amounts calculated pursuant to Section 5.2 for that prior calendar year with each Utility then incorporating its Percentage Share of any additional Hedge Credit or Hedge Cost amounts into its rates for the next Forecast Period in accordance with its approved tariffs and adjustment mechanisms.

Section 5.4 Reporting. BHUH shall promptly report to each Utility the calculations of Hedge Forecast Amounts and Percentage Share, and each Utility shall file such information with its PUC as part of its next PGA/GCA/ECA Filing.

Section 5.5 Annual Report. After the Hedge Year-End Amount has been calculated for a calendar year, BHUH shall promptly prepare an annual report setting forth the following:

(i) For that calendar year, each Utility's Hedge Target and Percentage Share, Actual ROE, Allowed ROE, Hedge Forecast Amounts, Hedge Year-End Amount, and COSGCO's financial statements;

(ii) For each calendar month in that calendar year, the volume of Gas, NGLs and other Hydrocarbons that COSGCO sold; and

(iii) COSGCO's reserves as of the end of that calendar year.

The Hydrocarbon Monitor shall assess whether COSGCO's reported reserves were calculated in accordance with standard industry practice and shall document its findings in writing. The Accounting Monitor shall prepare an assurance report regarding the accuracy of BHUH's calculations under this COSG Agreement during that calendar year. BHUH shall promptly provide the annual report, the Hydrocarbon Monitor's findings, and the Accounting Monitor's assurance report to each Utility, and each Utility shall file such information with its PUC as part of its next PGA/GCA/ECA Filing.

If the Hydrocarbon Monitor concludes that COSGCO's reported reserves were not calculated in accordance with standard industry practice and BHUH and the Hydrocarbon Monitor cannot agree on the appropriate change, then a third-party reservoir engineer (mutually agreeable to BHUH and the Hydrocarbon Monitor) shall be retained to resolve the difference in opinion. If the Accounting Monitor concludes that BHUH's calculations were not accurate and BHUH and the Accounting Monitor cannot agree on the appropriate change, then each Utility shall refer the Accounting Monitor's proposed adjustment to its PUC for resolution.

Section 5.6 Indirect Costs. COSGCO shall not be included in BHUH's and Black Hills Service Company's respective "Cost Allocation Manual, and no indirect costs shall be allocated to BHUH's performance of this COSG Agreement or included in the calculations under ARTICLE 5. Direct charges from BHUH and its affiliates for time spent providing services for the benefit of COSGCO shall be included in COSGCO OpEx.

Section 5.7 Reserve Pool. For accounting purposes, COSGCO shall maintain its own reserve pools separate from Black Hills Exploration and Production, Inc., such reserve pools shall be limited to proved developed producing reserves, and in accordance with SEC Regulation S-X Rule 4-10, Investment Base shall not be subject to the cost center ceilings test.

ARTICLE 6 - TERM AND TERMINATION

Section 6.1 Term. This COSG Agreement shall be effective from the Effective Date and shall continue in full force and effect for each Utility until the existing wells on each Property at the time of acquisition by COSGCO and the wells BHUH causes COSGCO to drill on the Properties pursuant to the Drilling Plan(s) and Drilling Plan II(s) (but excluding any wells for which the Utility is a Non-Participating Utility) have been plugged and abandoned and the portions of the Properties affected by such wells reclaimed in accordance with applicable law (**"Term"**), *provided* that each Utility's rights and obligations under this COSG Agreement may be terminated early as provided below in this ARTICLE 6. Applicable provisions of this COSG Agreement shall continue in effect after expiration of this COSG Agreement or early termination to the extent necessary to (i) provide for final billings, payments and adjustments, and (ii) enforce or complete the duties, obligations or responsibilities of the Parties.

Section 6.2 Early Termination by Utility. If a Utility is ordered by its PUC to terminate its rights and obligations under this COSG Agreement before the end of the Term, the Utility shall provide notice to BHUH. Upon receipt of a termination notice, BHUH shall cause COSGCO to sell, as soon as practical, an interest in the Properties (but excluding any Property and/or wells for which the terminating Utility is a Non-Participating Utility) that is functionally equivalent to the terminating Utility's Percentage Share for the calendar year in which such sale(s) closes, *provided* that no sale(s) shall occur until the remaining Utilities have approved the interest to be sold and the terminating Utility has approved the sale price(s). Following the sale, Investment Base shall be adjusted to reflect such sale(s). The termination of the terminating Utility's rights and obligations under this COSG Agreement shall be effective at the end of the calendar month in which the sale (or, if COSGCO sells such interest through multiple transactions, the last sale) closes, *provided* that (i) any amount due under Section 6.4 and any reconciliation amount owed under Section 5.3 shall be promptly paid, (ii) until such sale closes, the terminating Utility shall continue to receive any credits and incur any costs required under ARTICLE 5, and (iii) if no third party(ies) is willing to purchase such interest, the terminating Utility shall remain bound to this COSG Agreement until the end of the Term.

Section 6.3 Early Termination by BHUH. If BHUH determines, in its sole discretion, that any Non-Participating Utilities and/or terminating Utilities under Section 6.2 make continued performance of this COSG Agreement infeasible, BHUH may elect to terminate this COSG Agreement by providing notice to the Utilities. If BHUH elects to terminate, BHUH shall then cause COSGCO to sell, as soon as practical, all of its interest in the Properties, *provided* that no sale(s) shall occur until the Utilities have approved the sale price(s). The termination of the rights and obligations under this COSG Agreement shall be effective at the end of the calendar month in which the sale (or, if COSGCO sells its interests in the Properties through multiple transactions, the last sale) closes, *provided* that (i) any amount due under Section 6.4 and any reconciliation amount owed under Section 5.3 shall be promptly paid, (ii) until such sale closes, the Utilities shall continue to receive any credits and incur any costs required under ARTICLE 5, and (iii) if no third party(ies) is willing to purchase COSGCO's interests in the Properties, the Parties shall remain bound to this COSG Agreement until the end of the Term.

Section 6.4 Sale Proceeds. If the proceeds from a sale(s) under Section 6.2 or Section 6.3 (after deducting the transaction costs and Taxes incurred by BHUH or COSGCO in connection with such sale(s)) are greater than the Early Termination Amount multiplied by the Utility's Percentage Share for the calendar year in which the sale (or, if COSGCO sells through multiple transactions, the last sale) closes, then the difference shall be paid to the Utility and shall be incorporated into its rates as a credit to customers in accordance with its approved tariffs and adjustment mechanisms. If said proceeds are less than the Early Termination Amount multiplied by the Utility's Percentage Share for the calendar year in which such sale closes, then the Utility shall pay BHUH the difference and incorporate the difference into its rates as a cost to customers in accordance with its approved tariffs and adjustment mechanisms. No other Utility shall have any claim to any payment made under this Section 6.4.

BHUH shall calculate the "**Early Termination Amount**" pursuant to the following formula, as reasonably calculated by BHUH:

*Early Termination Amount = Net Cap. Costs + (Net Cap. Costs * Cost of Capital) + Net Op. Costs*

WHERE:

"**Net Cap. Costs**" shall be an amount equal to Investment Base (as defined in ARTICLE 1 but excluding any Properties and/or wells for which the relevant Utility is a Non-Participating Utility plus the estimated capitalized costs, if any, that COSGCO will remain obligated to pay in connection with the sold interests under any binding agreements with third parties) plus the net present value (in nominal dollars using the then-applicable Cost of Capital as the discount rate) of any minimum daily quantity penalties that COSGCO may incur as a result of the termination.

"**Net Op. Costs**" shall be an amount equal to the estimated operating costs, if any, that COSGCO will remain obligated to pay in connection with the sold interests under any binding agreements with third parties.

ARTICLE 7 - ADDITIONAL COVENANTS

Section 7.1 Neither BHUH nor the Utilities shall provide financing for, extend credit to, issue long-term debt for or pledge utility assets in support of the activities of COSGCO contemplated by this COSG Agreement.

Section 7.2 Neither BHUH nor the Utilities shall guarantee any new debt obligations, notes, debentures, or any other security of Black Hills Corporation, a South Dakota corporation, or its non-utility operations.

Section 7.3 Stand-alone or project financing for COSGCO's activities shall be without recourse to either BHUH or the Utilities.

ARTICLE 8 - CONDITION SUBSEQUENT

Section 8.1 This COSG Agreement shall have no force and effect unless and until each PUC has approved this COSG Agreement in full and without modification in orders satisfactory to BHUH and the Utilities, *provided* that if each PUC does not so approve this COSG Agreement, then BHUH and each Utility for which its respective PUC has so approved this COSG Agreement shall have the right, but not the obligation, to deem this COSG Agreement effective as to such Utility.

ARTICLE 9 - MISCELLANEOUS

Section 9.1 Replacement Forecasts and Reports. If a forecast that comprises part of the Long-Term Market Price Forecast ceases to be published or Regulatory Research Associates ceases to report the average annual return on equity in gas and electric utility rate cases, then BHUH shall promptly select an appropriate alternative forecast or report to achieve the same effect.

Section 9.2 Default; Remedies. If any Party fails or refuses to comply with any of the terms and conditions of this COSG Agreement, any other Party may notify that Party (and the other Parties) in writing of such alleged default, specifying the nature and character of the default. The defaulting Party shall have sixty (60) calendar days after receipt of such notice within which to initiate good-faith action to correct the alleged default, *provided* that in the event the defaulting Party in good faith contests such alleged default, the defaulting Party may give written notice of such contest to the other Parties within said sixty (60) calendar day period, and in such event, the Parties shall proceed to resolve the dispute in as provided in Section 9.3. The Parties shall continue performance of this COSG Agreement during the pendency of any such dispute resolution proceeding. If the dispute resolution process determines that the alleged default occurred, the defaulting Party shall have fifteen (15) calendar days after the date of such to begin good-faith curative action.

Section 9.3 Dispute Resolution.

(i) Panel of Senior Executives. Each Party shall select a senior executive with authority to decide or resolve the matter in dispute. Such senior executives shall meet and in good faith attempt to resolve the dispute within thirty (30) calendar days. If the Parties are unable to resolve the dispute pursuant to this Section 9.3(i), any Party may enforce its rights pursuant to Section 9.3(ii).

(ii) Arbitration. If any Party alleges that there is a default by the other Party of its obligations under this COSG Agreement, such dispute shall be finally resolved by arbitration in Rapid City, South Dakota before one (1) arbitrator. The Parties shall request that an arbitrator be provided who has experience with the resolution of disputes related to the acquisition and development of oil and gas properties as the matter may require. The arbitration shall be administered by JAMS pursuant to its Comprehensive Arbitration Rules and Procedures. Judgment on the award may be entered in any court having jurisdiction. This clause shall not preclude the Parties from seeking provisional remedies in aid of arbitration from a court of appropriate jurisdiction. The Parties shall equally share the costs of the arbitration proceeding and shall otherwise each pay their own costs related to the arbitration, including attorneys' fees and expert witness costs, *provided* that the arbitrator shall have authority to assess the costs of the arbitration proceeding, as well the prevailing Party's costs, including attorneys' fees and expert witness costs, against the non-prevailing Party as part of the award. The Parties shall be legally bound by the arbitrator's decision and agree that review of the arbitrator's decision shall be limited to those grounds specified in the Federal Arbitration Act. If any Party fails to proceed with arbitration, fails to comply with the decision, or unsuccessfully challenges the decision, that Party must pay all of the other Party's costs of suit including reasonable attorneys' fees and expert witness costs incurred to enforce or defend such a decision.

Section 9.4 Force Majeure. If BHUH is rendered unable, wholly or in part, by a Force Majeure Event to carry out its obligations under this COSG Agreement, other than the obligations to make monetary payments, or if a Force Majeure Event renders COSGCO unable, wholly or in part, to perform BHUH's directives, then BHUH shall give the Utilities prompt written notice describing the Force Majeure Event in reasonable detail. Thereupon, the obligations of BHUH, so far as it is affected by the Force Majeure Event, shall be suspended for a period equal to the period of the continuance of the Force Majeure Event. BHUH shall itself, or shall cause COSGCO to, use all reasonable diligence to remove the Force Majeure Event as quickly as practicable. The requirement that any Force Majeure Event be remedied with all reasonable dispatch shall not require the settlement of strikes, lockouts or other labor difficulty by the Party affected, contrary to its wishes, and settlement or resolution of such matters shall be within the discretion of the affected Party. "**Force Majeure Event**" shall mean an act of God, act of terrorism, strike, lockout, or other industrial disturbance, act of the public enemy, war (declared or undeclared), blockade, public riot, landslide, lightning, fire, storm, storm warning that results in evacuation of the affected area, flood, washout, maintenance, integrity testing, breakage, blockage, accidents to or freezing of oil and gas production, processing or transportation equipment, explosion, governmental action, restraint or inaction, the interruption or suspension of the receipt or delivery of Gas due to the inability or failure of any third party not a Party to this COSG Agreement to receive or deliver such Gas, unavailability of equipment, or inability to gain access, ingress or egress to conduct operations (including delays in or inability to obtain permits, approvals or clearances, which includes permits or approvals related to the use of any specific fracture stimulation technology or methodology, from any governmental authority), and any other factor or circumstance beyond BHUH or COSGCO's control, whether foreseen, foreseeable or unforeseeable, that limits, delays or prevents either BHUH's performance of this COSG Agreement or COSGCO's production, processing, and/or sale of Hydrocarbons from the Properties and that could not have avoided by the exercise of due diligence. For the avoidance of doubt, if a Force Majeure Event prevents COSGCO from selling Hydrocarbons on the market to third parties, the Parties' respective rights and obligations under ARTICLE 5 shall not be suspended.

Section 9.5 Assignment. No Party may assign or transfer, by assignment, sale, merger or otherwise by operation of law, in whole or in part, any of its rights or obligations under this COSG Agreement without the prior written consent of the other Parties, which may be withheld by each in its sole discretion, and any attempted assignment or transfer without such prior written consent shall be void, *provided* that (i) this Section 9.5 shall not apply to a change of control in BHUH or a sale of substantially all of BHUH's assets to a third party, and (ii) if BHUH does not consent, then the PUC for the Utility seeking to assign or transfer shall be deemed to have ordered that Utility to terminate its rights and obligations under the COSG Agreement pursuant to Section 6.2.

Section 9.6 Notices. All notices and communications required or permitted under this COSG Agreement shall be in writing addressed as indicated below, and any communication or delivery made pursuant to this Section 9.6 shall be deemed to have been duly delivered and received upon the earliest of: (i) actual receipt by the Party to be notified; (ii) three (3) calendar days after deposit with the U.S. Postal Service, certified mail, postage prepaid, return receipt requested; or (iii) two (2) calendar days after deposit with Federal Express overnight delivery (or other reputable overnight delivery service), postage prepaid, return receipt requested. Addresses for all such notices and communication shall be as follows:

To BHUH:

Black Hills Utility Holdings, Inc.
c/a Black Hills Corporation
625 Ninth Street
Rapid City , SD 57701
ATTN: President

With a copy to:

Patrick Joyce
Senior Managing Counsel
Black Hills Corporation
1102 E. 1st Street
Papillion, NE 68046
Fax: 402-829-2691

To Utilities:

Black Hills Power, Inc.
409 Deadwood Avenue
Rapid City, SD 57702
ATTN: President

Black Hills/Colorado Electric Utility Company, LP
105 South Victoria
Pueblo, CO 81003
ATTN: President

Black Hills/Colorado Gas Utility Company, LP
7060 Alegre Street
Fountain, CO 80817
ATTN: President

Black Hills/Iowa Gas Utility Company, LLC
1701 48th Street # 260
West Des Moines, IA 50266
ATTN: President

Black Hills/Kansas Gas Utility Company, LLC
110 East 9th Street
Lawrence, KS 66044
ATTN: President

Black Hills/Nebraska Gas Utility Company, LLC
501 West 6th Street
Papillion, NE 68046
ATTN: President

Black Hills Northwest Wyoming Gas Utility Company, LLC
1301 West 24th Street
Cheyenne, WY 82001
ATTN: President

Cheyenne Light, Fuel & Power
1301 West 24th Street
Cheyenne, WY 82001
ATTN: President

With a copy to (regardless of the receiving Utility):

Patrick Joyce
Senior Managing Counsel
Black Hills Corporation
1102 East 1st Street
Papillion, NE 68046
Fax: 402-829-2691

Each Party may, upon written notice to the other Parties, change the address and person to whom such communications are to be directed.

Section 9.7 Relationship of the Parties. This COSG Agreement is not intended to create, and shall not be construed to create, an association for profit, a trust, a joint venture, a mining partnership or other relationship of partnership, or entity of any kind between the Parties. The Parties understand and agree that the liabilities of the Parties shall be several, not joint or collective and that each Party shall be solely responsible for its own obligations except as otherwise provided in this COSG Agreement.

Section 9.8 No Third-Party Beneficiary. This COSG Agreement is made solely for the benefit of the Parties and their permitted successors and assigns, and no other person shall have any right, benefit or interest under or because of this COSG Agreement. There are no intended third-party beneficiaries of this COSG Agreement.

Section 9.9 Entire Agreement. This COSG Agreement and the exhibits to this COSG Agreement contain the entire agreement of the Parties with respect to the subject matter of this COSG Agreement and supersede all previous agreements or communications between the Parties, verbal or written, with respect to the subject matter of this COSG Agreement.

Section 9.10 Governing Law. This COSG Agreement shall be governed by and construed and interpreted in accordance with the laws of the State of South Dakota, without reference to its conflict of law provisions.

Section 9.11 Amendments; Waiver. No amendments or other modifications or changes to this COSG Agreement shall be effective or binding on any Party unless the same shall be in a writing executed by all Parties, *provided* that BHUH may agree to another utility(ies) becoming a party(ies) to this COSG Agreement, without a writing being executed by the Utilities and approved by their PUCs, but subject to the following limitations: (i) the terms and conditions to which the Utilities are bound under the COSG Agreement shall remain the same; and (ii) any such added utility shall be deemed a Non-Participating Utility with respect to any Property approved pursuant to Section 4.3 before such utility becomes a party to this COSG Agreement. No waiver by any Party of any one or more defaults by the other in the performance of this COSG Agreement shall operate or be construed as a waiver of any future default or defaults, whether of a like or different nature.

Section 9.12 Public Announcements. Unless otherwise agreed or required by law as determined by a Party, a Party may make any public announcement or statement with respect to this COSG Agreement or the transactions contemplated by this COSG Agreement without the consent of the other Parties, *provided* that the non-announcing Parties shall be afforded an opportunity to review and comment upon any required public announcement or statement prior to the announcement or statement being made.

Section 9.13 Severability. If a court of competent jurisdiction determines that any clause or provision of this COSG Agreement is void, illegal, unenforceable or unconscionable under any present or future law (or interpretation thereof), the remainder of this COSG Agreement shall remain in full force and effect, and the clauses or provisions that are determined to be void, illegal, unenforceable or unconscionable shall be deemed severed from this COSG Agreement as if this COSG Agreement had been executed with the invalid provisions eliminated, *provided* that (i) upon any such determination, the Parties shall negotiate in good faith to modify this COSG Agreement so as to affect the original intent of the Parties as closely as possible, and (ii) if the removal of such provisions destroys the legitimate purposes of this COSG Agreement, then this COSG Agreement shall no longer be of any force or effect.

Section 9.14 Further Assurances. The Parties shall execute, acknowledge and deliver or cause to be executed, acknowledged and delivered such instruments and take such other action as may be necessary or advisable to carry out their obligations under this COSG Agreement and under any document or other instrument delivered pursuant to this COSG Agreement.

Section 9.15 Rules of Construction. The headings of the articles and sections of this COSG Agreement are for guidance and convenience of reference only and shall not limit or otherwise affect any of the terms or provisions of this COSG Agreement. All references in this COSG Agreement to articles, sections, subsections and other subdivisions refer to corresponding articles, sections, subsections and other subdivisions of this COSG Agreement unless expressly provided otherwise. Titles appearing at the beginning of any of such subdivisions are for convenience only and shall not constitute part of such subdivisions and shall be disregarded in construing the language contained in such subdivisions. "Including" and its grammatical variations mean "including without limitation." Unless the context otherwise requires, "or" is not exclusive; words in the singular form shall be construed to include the plural and vice versa; words in any gender include all other genders; references in this COSG Agreement to any instrument or agreement refer to such instrument or agreement as it may be from time to time amended or supplemented; and references in this COSG Agreement to any Party include such Party's permitted successors and assigns. All references in this COSG Agreement to exhibits refer to exhibits attached to this COSG Agreement unless expressly provided otherwise. This COSG Agreement has been drafted with the joint participation of BHUH and the Utilities and shall be construed neither against nor in favor of either one Party but in accordance with the fair meaning of its terms.

Section 9.16 Execution in Counterparts. This COSG Agreement may be executed by signing an original or a counterpart. If this COSG Agreement is executed in counterparts, all counterparts taken together shall have the same effect as if all the Parties had signed the same instrument.

Each Party caused this COSG Agreement to be executed, by its duly authorized representative, as of the day and year first above written.

BHUH:

Black Hills Utility Holdings, Inc.,
a South Dakota corporation

By: ______________________________
Name: ____________________________
Title: _____________________________

Utilities:

Black Hills Power, Inc.,
a South Dakota corporation

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills/Colorado Electric Utility Company, LP,
a Delaware limited partnership

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills/Colorado Gas Utility Company, LP,
a Delaware limited partnership

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills/Iowa Gas Utility Company, LLC,
a Delaware limited liability company

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills/Kansas Gas Utility Company, LLC,
a Delaware limited liability company

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills/Nebraska Gas Utility Company, LLC,
a Delaware limited liability company

By: ______________________________
Name: ____________________________
Title: _____________________________

Black Hills Northwest Wyoming Gas Utility Company, LLC,
a Delaware limited partnership

By: ______________________________
Name: ____________________________
Title: _____________________________

Cheyenne Light, Fuel and Power Company,
a Wyoming corporation

By: ______________________________
Name: ____________________________
Title: _____________________________

EXHIBIT A

Acquisition Criteria

1. A Property must have:

    a. On a net present value basis (in nominal dollars using the then-applicable Cost of Capital as the discount rate), a COSG Cost Forecast for the term of its Reserve Report that is less than the then-current Long-Term Market Price Forecast of Gas prices for the same volumes over the same period, so that it is reasonably anticipated, based on then-available information, that its acquisition and development pursuant to the Proposed Drilling Program will generate a savings for the Utilities' customers;

    b. Proved developed producing reserves equal to at least fifty percent (50%) of the net present value of the acquisition by COSGCO (using the then-applicable Cost of Capital as the discount rate), but this criterion shall not apply if COSGCO is to earn interests in the Property through drilling;

    c. An expected remaining producing life of at least fifteen (15) years; and

    d. At least fifty percent (50%), on a btu basis, of its anticipated Hydrocarbon production consist of Gas.

2. A Property must be located:

    a. In the Rockies or Mid-continent regions of the United States and must contain formations with (i) an established history of Gas production, (ii) low dry hole risk, and (iii) an established history of reserves per well and costs per well; and

    b. At or near trading hub locations to minimize costs to transport Gas to market.

3. If the Property is to be acquired from, or operated by, Black Hills Exploration and Production, Inc. or any other affiliate of Black Hills Corporation, then an independent third party must have issued a valuation opinion concluding the following:

    a. COSGCO's proposed transaction with that affiliate is fair based on other deals with unrelated third parties that are known in the market; and

    b. The terms of any agreements to which COSGCO would become a party through the transaction with that affiliate are commercially reasonable.

EXHIBIT B

Drilling Plan Criterion

The wells to be developed under the updated Drilling Plan before the next Five-Year Anniversary must have on a net present value basis (in nominal dollars using the then-applicable Cost of Capital as the discount rate) a COSG Cost Forecast for their producing life as determined by the Reserve Report that is less than the then-current Long-Term Market Price Forecast for Gas for the same volumes over the same period, so that it is reasonably anticipated, based on then-available information, that developing these wells will generate a savings to the Utilities' customers.

EXHIBIT C

Percentage Share and Hedge Target

Each Utility's Hedge Target and Percentage Share for 2016 are as follows:

Utility	Current Annual Demand (in Dths)	Hedge Target (in Dths)	Percentage Share
Black Hills Power, Inc. (South Dakota and Wyoming only)	600,000	300,000	0.83%
Black Hills/Colorado Electric Utility Company, LP	10,500,000	5,250,000	14.46%
Black Hills/Colorado Gas Utility Company, LP	8,500,000	4,250,000	11.71%
Black Hills/Iowa Gas Utility Company, LLC	17,300,000	8,650,000	23.83%
Black Hills/Kansas Gas Utility Company, LLC	13,000,000	6,500,000	17.91%
Black Hills/Nebraska Gas Utility Company, LLC	16,200,000	8,100,000	22.31%
Black Hills Northwest Wyoming Gas Utility Company, LLC	1,400,000	700,000	1.93%
Cheyenne Light, Fuel and Power Company (gas)	4,700,000	2,350,000	6.47%
Cheyenne Light, Fuel and Power Company (elec.)	400,000	200,000	0.55%
Aggregate	*72,600,000*	*36,300,000*	*100%*

EXHIBIT D

Sample Hedge Credit Calculation

Line No.	Item	Formula	Amount	Description
1	**Per Section 5.1(i), the formula for calculating a Hedge Credit is as follows:**			
2				
3	***Hedge Credit = -(Net Income-((Allowed ROE + 100 basis points) * Invested Equity)) * 1/(1-T)***			
4				
5	For example only, the following is how Section 5.1(i) would work in a hypothetical month:			
6			3,250,000	COSGCO Revenue from sales of Hydrocarbons
7				COSGCO OpEx
8			2,324,000	Operating Expenses
9			111,075	Interest Exp (40% of Investment Base)
10			814,925	Income Before Taxes
11			309,672	Ln 10 * 38% (Federal and State Income Taxes)
12	Net Income =		505,254	
13			**1.61**	**Tax Gross up (1/(1-.38)**
14	**Hedge Credit**		**(166,366)**	=-(ln12-((ln21+ln27)*ln25))*ln13
15				
16	Assumptions for the above calculation:			
17	Equity %		60.00%	
18	**Allowed ROE**		9.86%	
19	Debt %		40.00%	
20	**Allowed Cost of Debt**		4.50%	
21	Allowed ROE (monthly)	ln 18 ÷ 12	0.8217%	
22	Allowed Cost of Debt (monthly)	ln 20 ÷ 12	0.3750%	
23	Debt Expense (monthly)	ln 24 * ln 19 * ln 22	111,075	
24	Investment Base		**74,050,000**	
25	Invested Equity	ln 24 * ln 17	44,430,000	
26	100 Basis Points		1.00%	
27	100 Basis Points (monthly)	ln 26 ÷ 12	0.083%	
28	Actual ROE (monthly)	ln 12 ÷ ln 25	1.1372%	

Sample Hedge Cost Calculation

Line No.				
1	Per Section 5.1(ii), the formula for calculating a Hedge Cost is as follows:			
2				
3	*Hedge Cost = -(Net Income-((Allowed ROE - 100 basis points) * Invested Equity)) * 1/(1-T)*			
4				
5	For example only, the following is how Section 5.1(ii) would work in a hypothetical month:			
6			2,450,000	COSGCO Revenue from sales of Hydrocarbons
7				**COSGCO OpEx**
8			2,054,000	Operating Expenses
9			86,075	Interest Exp (40% of Investment Base)
10			309,925	Income Before Taxes
11			117,772	Ln 10 * 38% (Federal and State Taxes)
12	Net Income =		192,154	
13			1.61	Tax Gross up (1/(1-.38)
14	Hedge Cost		100,107	=-(ln12-((ln21-ln27)*ln25))*ln13
15				
16	Assumptions for the above calculation			
17	Equity %		60.00%	
18	Allowed ROE		9.86%	
19	Debt %		40.00%	
20	Allowed Cost of Debt		4.50%	
21	Allowed ROE (monthly)	ln 18 ÷ 12	0.8217%	
22	Allowed Cost of Debt (monthly)	ln 20 ÷ 12	0.3750%	
23	Debt Expense (monthly)	ln 24 * ln 19 * ln 22	86,075	
24	Investment Base		57,383,333	
25	Invested Equity	ln 24 * ln 17	34,430,000	
26	100 Basis Points		1.00%	
27	100 Basis Points (monthly)	ln 26 ÷ 12	0.083%	
28	Actual ROE (monthly)	ln 12 ÷ ln 25	0.5581%	

BLACK HILLS ENERGY

APPLICATION NO. NG-0086

RESPONSE OF BLACK HILLS ENERGY TO

SECOND SET OF DATA REQUESTS OF THE PUBLIC ADVOCATE

DATE OF REQUEST	:	**January 8, 2016**
DATE RESPONSE DUE	:	**January 22, 2016**
DATE RESPONDED	:	**January 22, 2016**
REQUESTING PARTY	:	**Nebraska Public Advocate**
WITNESS	:	**Ivan Vancas**

REQUEST NO. PA-33:

Does Black Hills believe that approval of reserve acquisitions and drilling plans is within the Commission's and the PA's expertise? Does Black Hills expect the Commission and the Parties to contract for such expertise, or are the Hydrocarbon Monitor and Accounting Monitor intended to fulfill such needs?

RESPONSE:

The Company is not fully aware of the extent of the Commissions' or the PA's familiarity or experience with reserve acquisitions or drilling plans. However, as described in the direct testimony of Mr. Carr, Page 6, where Commissions, Boards and Consumer Advocates may lack the personnel with technical expertise and experience with natural gas production to monitor each aspect of the functions of the COSG Program and/or to evaluate and approve reserve acquisitions, the COSG Program incorporates assistance for the Commission, its staff, and consumer advocates. Specifically, not only will the Independent Hydrocarbon Monitor provide support and expertise regarding natural gas reserve reports, acquisitions, and drilling plans, but the Accounting Monitor will also provide an annual report regarding the financial operations of the program. In the case of a proposed reserve acquisition, the Company would provide the Commission with a report from the Independent Hydrocarbon Monitor advising whether the proposed acquisition and associated drilling program satisfies the Acquisition Criteria. Similarly in the context of the five-year drilling plan review, the Company would provide the Commission with a report from the Independent Hydrocarbon Monitor advising whether it satisfies the Drilling Plan Criterion.

The Commission and the Parties could also choose to contract for expertise in addition to the Independent Monitors at their discretion.

ATTACHMENTS: None.

Response provided by: **Ivan Vancas**

Energy Prices

Publication Date: February 8, 2016

			2015	2016	2017
	Crude Oil Prices				
WTIPUUS	West Texas Intermediate Spot Average	*(dollars per barrel)*	**48.67**	*37.59*	*50*
RAIMUUS	Imported Average	*(dollars per barrel)*	**46.42**	*34.15*	*46.63*
RACPUUS	Refiner Average Acquisition Cost	*(dollars per barrel)*	**48.5**	*36.58*	*49.12*
BREPUUS	Brent Spot Average	*(dollars per barrel)*	**52.32**	*37.52*	*50*
	U.S. Liquid Fuels				
	Refiner Prices for Resale				
MGWHUUS	Gasoline	*(cents per gallon)*	**172**	*124*	*149*
DSWHUUS	Diesel Fuel	*(cents per gallon)*	**167**	*126*	*161*
D2WHUUS	Heating Oil	*(cents per gallon)*	**153**	*119*	*155*
	Refiner Prices to End Users				
JKTCUUS	Jet Fuel	*(cents per gallon)*	**162**	*121*	*156*
RFTCUUS	No. 6 Residual Fuel[a]	*(cents per gallon)*	**126**	*92*	*120*
	Retail Prices Including Taxes				
MGRARUS	Gasoline Regular Grade[b]	*(cents per gallon)*	**243**	*198*	*221*
MGEIAUS	Gasoline All Grades[b]	*(cents per gallon)*	**252**	*207*	*230*
DSRTUUS	On-highway Diesel Fuel	*(cents per gallon)*	**271**	*222*	*258*
D2RCAUS	Heating Oil	*(cents per gallon)*	**265**	*209*	*241*
	Natural Gas				
NGHHMCF	Henry Hub Spot	*(dollars per thousand cubic feet)*	**2.71**	*2.72*	*3.32*
NGHHUUS	Henry Hub Spot	*(dollars per million Btu)*	**2.63**	*2.64*	*3.22*
	U.S. Retail Prices				
NGICUUS	Industrial Sector	*(dollars per thousand cubic feet)*	**3.84**	*3.7*	*4.35*
NGCCUUS	Commercial Sector	*(dollars per thousand cubic feet)*	**7.88**	*7.56*	*8.2*
NGRCUUS	Residential Sector	*(dollars per thousand cubic feet)*	**10.36**	*9.83*	*10.21*
	U.S. Electricity				
	Power Generation Fuel Costs				
CLEUDUS	Coal	*(dollars per million Btu)*	**2.23**	*2.18*	*2.2*
NGEUDUS	Natural Gas	*(dollars per million Btu)*	**3.26**	*3.54*	*4.05*
RFEUDUS	Residual Fuel Oil[c]	*(dollars per million Btu)*	**10.42**	*7.72*	*9.27*
DKEUDUS	Distillate Fuel Oil	*(dollars per million Btu)*	**14.48**	*11.52*	*14.34*
	Retail Prices				
ESICUUS	Industrial Sector	*(cents per kilowatthour)*	**6.9**	*6.95*	*7.07*
ESCMUUS	Commercial Sector	*(cents per kilowatthour)*	**10.6**	*10.74*	*10.95*
ESRCUUS	Residential Sector	*(cents per kilowatthour)*	**12.66**	*12.68*	*13.1*

(a) Average for all sulfur contents.
(b) Average self-service cash price.
(c) Includes fuel oils No. 4, No. 5, No. 6, and topped crude.
- = no data available
Notes: Prices are not adjusted for inflation.
The approximate break between historical and forecast values is shown with estimates and forecasts in italics.
Prices exclude taxes unless otherwise noted.
Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Petroleum Marketing Monthly* , DOE/EIA-0:
Weekly Petroleum Status Report , DOE/EIA-0208; *Natural Gas Monthly* , DOE/EIA-0130; *Electric Power Monthly* , DOE/EIA-0226; and *Monthly Energy Review* , DC
Natural gas Henry Hub and WTI crude oil spot prices from Reuter's News Service (http://www.reuters.com).
Minor discrepancies with published historical data are due to independent rounding.
Projections: EIA Regional Short-Term Energy Model.

BLACK HILLS ENERGY

APPLICATION NO. NG-0086

RESPONSE OF BLACK HILLS ENERGY TO

FIRST SET OF DISCOVERY REQUESTS OF CONSTELLATION

DATE OF REQUEST	:	**January 19, 2016**
DATE RESPONSE DUE	:	**February 2, 2016**
DATE RESPONDED	:	**February 2, 2016**
REQUESTING PARTY	:	**Constellation Newenergy-Gas Division, LLC (CNEG)**
WITNESS	:	**Ivan Vancas**

REQUEST NO. CNEG 1-12: If the public utility commissions concurrently reviewing the COSG Program decline to approve the Program, does Black Hills intend to purchase natural gas reserves without the guaranteed cost recovery proposed through the Program?

RESPONSE: BHUH would not acquire reserves to provide a long-term supply hedge to utility customers absent the COSG Program. Within the Black Hills family of companies, only BHEP acquires and develops properties as a traditional exploration and production company. If BHEP did acquire or develop reserves, absent the COSG Program, those reserves would not specifically be developed for the Black Hills utilities.

ATTACHMENTS: None.

Response provided by: **Ivan Vancas**

BLACK HILLS ENERGY

APPLICATION NO. NG-0086

RESPONSE OF BLACK HILLS ENERGY TO

FIRST SET OF DATA REQUESTS OF THE PUBLIC ADVOCATE

DATE OF REQUEST	:	**December 15, 2015**
DATE RESPONSE DUE	:	**December 29, 2015**
DATE RESPONDED	:	**December 29, 2015**
REQUESTING PARTY	:	**Nebraska Public Advocate**
WITNESS	:	**Ivan Vancas**

REQUEST NO. PA-4:

Referring to Mr. Vancas' Testimony at page 5, what level of hedging (i.e., percentage of the Company's firm demand) does the Company believe is the breakeven point between moving ahead with this proposal versus maintaining the status quo?

RESPONSE: The Company objects to this request on the basis that it is vague and ambiguous in that it is unclear what is meant by the phrase "the breakeven point between moving ahead with this proposal versus maintaining the status quo." Subject to this objection and based upon its understanding of this Request, the Company responds as follows:

The Company does not have a state-specific breakeven point nor has it made any predetermination of a lower percentage of its general system natural gas portfolio as this program is focused on achieving the 50% long-term hedge based on analyses and the recommendations by Aether Advisors. Once BHUH knows the actual portfolio percentage commitments from the multiple states in which Black Hills Utilities have applied, then it will reevaluate the feasibility of continuing the COSG Program.

The 50% recommendation for reserves acquisition is based upon several factors. As described in the Aether Report, a meaningful volume commitment will bring greater economies of scale than a smaller program. The effort involved would not make sense to pursue if the COSG Program did not provide meaningful hedging protection to customers. From a market price perspective, indications are that the time is opportune. In a rising price environment customers are better protected with a higher percentage of hedging. Natural gas prices are currently at historical lows, but there are many indications prices will need to rise to encourage production growth to meet future demand increases.

ATTACHMENTS: None.

Response provided by: **Ivan Vancas**

BLACK HILLS ENERGY

APPLICATION NO. NG-0086

RESPONSE OF BLACK HILLS ENERGY TO

FIRST SET OF DISCOVERY REQUESTS OF CONSTELLATION

DATE OF REQUEST	:	**January 19, 2016**
DATE RESPONSE DUE	:	**February 2, 2016**
DATE RESPONDED	:	**February 2, 2016**
REQUESTING PARTY	:	**Constellation Newenergy-Gas Division, LLC (CNEG)**
WITNESS	:	**Ivan Vancas**

REQUEST NO. CNEG 1-16: Please explain the Company's understanding of the Commission's authority if, at some point after approval of the proposed COSG Program, the Commission determines the COSG Agreement is no longer in the best interest of the ratepayers. Please cite all Commission/State rules and/or statutes that support the Company's answer.

A. What would be the financial responsibility of the Company's ratepayers considering the Company would then be the owner of natural gas reserve assets that are no longer guaranteed to earn a profit?

B. What would be the impact on the Company's financial viability?

RESPONSE:

The Company objects to this Request on the basis that it seeks to require the Company to provide information that is equally available to CNEG. Subject to that objection, the Company responds as follows:

The COSG Program would not change the Commission's authority or powers, which are set out in application Nebraska statutes, regulations and rules. CNEG has equal access to those statutes, regulations and rules and can readily assess the Commissions' authority.

As set forth in the Company's application in this proceeding, the Company is requesting, among other things, approval of the COSG Program structure and the Company's participation in the COSG Agreement, including its terms. If the Commission approved the COSG Program and the COSG Agreement, the Commission would have the authority not to approve acquisitions or drilling programs. *See* COSG Agreement, Article IV. If the Commission approved an acquisition and drilling program, the Company would be required to satisfy any obligations associated with that acquisition and drilling program, in the same way the Company is required to perform its obligations under other utility-related agreements approved by the Commission, regardless of whether the Commission later believed the contract was no longer in the best interest of ratepayers. As such, the Company would not expect that the Commission would attempt to cause the Company to breach its obligations under the agreement.

In addition, the Commission would continue to have authority not to approve later acquisitions or drilling plans, and could order a utility to terminate its right and obligations. *See* Articles IV, and Section 6.2.

A. The Company disagrees with the request to the extent that it characterizes any profit earned under the COSG Program as a guaranteed profit. In addition, the Company disagrees that it would ever be the owner of natural gas assets. With those clarifications, the financial responsibility of the Company (Black Hills Nebraska Gas Utility) and, by extension, its customers, are provided for in the COSG Agreement. In the specific circumstance of termination, if the Commission ordered the Company to terminate its rights under the COSG Agreement, the Company would have the financial responsibilities set forth in Section 6.2 of the COSG Agreement, as well as other provisions of the agreement. The consequences are similar to the early termination of a financial hedge, long-term gas purchase agreement, or long-term power purchase agreement.

B. The Company objects to this Request on the basis that it is vague and ambiguous in that it is unclear what the question is referring to. If the question seeks to understand what the financial impact would be on the Company if it were later required to terminate its participation in the COSG Program, the Company cannot respond to this question at this time as it would have to know what the Company's level of participation in the program was at the time of termination, what acquisitions and drilling programs had been approved, what the Company's interest in the COSG Program could be sold for, and the financial condition of the Company and the market at the time of the termination. The impact on the Company would be minimal; the impact on Black Hills Corporation could be material in the event that there are not similar investment opportunities for the Corporation's capital.

ATTACHMENTS: None.

Response provided by: **Legal/Ivan Vancas**

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NEBRASKA

IN THE MATTER OF BLACK HILLS/NEBRASKA GAS UTILITY COMPANY, LLC, d/b/a BLACK HILLS ENERGY, OMAHA, SEEKING APPROVAL OF ITS COST OF SERVICE HEDGE AGREEMENT WITH BLACK HILLS UTILITY HOLDINGS, INC.	)))))	APPLICATION NO. NG-0086

STATE OF SOUTH CAROLINA COUNTY OF GREENVILLE	))	AFFIDAVIT ADOPTING DIRECT TESTIMONY

Michael J. McGarry, Sr. being first duly sworn on oath, states that he is the Michael J. McGarry, Sr. whose Direct Testimony in the above-captioned proceeding accompanies this Affidavit.

Michael J. McGarry, Sr further states that such Direct Testimony is a true and accurate statement of her answers to the questions contained therein, and that she does adopt those answers as her own Testimony in this proceeding.

Michael J. McGarry Sr

On the 12 day of February, 2016, before me, the undersigned, a Notary Public commissioned and qualified for in said County, personally came Michael J. McGarry Sr, to me known to be the identical person whose names are affixed to the foregoing Testimony and acknowledged the execution thereof to be her voluntary act and deed.

WITNESS my hand and Notary Seal the day and year last above written.

Laurie B Faust
Notary Public
My Commission Expires: My Commission Expires December 27th, 2017