BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

IN THE MATTER OF THE APPLICATION	**)**	
OF BLACK HILLS/ KANSAS GAS UTILITY	**)**	
COMPANY, LLC, d/b/a BLACK HILLS	**)**	**Docket No. 16-BHCG-171-TAR**
ENERGY FOR APPROVAL OF ITS LONG	**)**	
TERM PHYSICAL GAS HEDGE CONTRACT	**)**	
WITH BLACK HILLS UTILITY HOLDINGS, INC.	**)**	

DIRECT TESTIMONY OF

ANDREA C. CRANE

ON BEHALF OF

KANSAS CITIZENS' UTILIITY RATEPAYER BOARD

March 21, 2016

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Andrea C. Crane and my business address is 3300 NE 36th Street, #608, Ft. Lauderdale, FL 33308. (Mailing Address: P.O. Box 810, Georgetown, Connecticut 06829)

Q. By whom are you employed and in what capacity?

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989. I became President of the firm in 2008.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in approximately 400 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, Washington, West Virginia and the District of Columbia. These proceedings involved gas, electric, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony since January 2008 is included in Appendix A.

Q. Have you previously testified in regulatory proceedings in Kansas?

A. Yes, I have. I have testified in numerous proceedings in Kansas. I have testified in utility proceedings involving Black Hills Energy, Kansas Gas Service, Atmos Energy, Westar Energy, Kansas City Power and Light Company, and others.

Q. What is your educational background?

A. I received a Master of Business Administration degree, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

Q. On whose behalf are you providing testimony?

A. The Columbia Group, Inc. was engaged by the Kansas Citizens' Utilities Ratepayer Board (“CURB”) to review the Application of Black Hills/Kansas Gas Utility Company, LLC d/b/a Black Hills Energy ("Black Hills Kansas" or "Company") for approval of a long-term physical gas hedge contract with Black Hills Utility Holdings, Inc. ("BHUH") and to develop recommendations for the Kansas Corporation Commission (“KCC” or “Commission”).

II. PURPOSE OF TESTIMONY

Q. What is the subject of Black Hills Kansas’ Application?

A. Black Hills Kansas is seeking an Order from the Commission authorizing the Company to enter into a Cost of Service Gas Agreement (the "COSG Agreement" or “Agreement”) with BHUH (an affiliated entity). Pursuant to the COSG Agreement, BHUH would establish a subsidiary, Cost of Service Gas Company (“COSGCO”), for the purpose of investing in gas reserves sufficient to provide up to 50% of Black Hills Kansas’ annual gas requirements. The COSG Agreement provides that Kansas ratepayers would be responsible for all costs of COSGCO, including return on investment as discussed below, and would share in any earnings above the level outlined in the COSG Agreement. The Application also seeks approvals for revised tariff sheets, for cost recovery via the Purchased Gas Adjustment ("PGA") and the Annual Cost Adjustment ("ACA") mechanisms, and for waivers from any affiliate rules or regulations or ring-fencing commitments that might be deemed applicable.

Q. What is the purpose of your testimony in this proceeding?

A. I was engaged to review the Company’s Application and to determine the impact of the proposal from a financial and regulatory policy perspective. While I discuss several provisions of the COSG Agreement in my testimony, I am not an attorney and my testimony is not intended to provide any legal conclusions.

III. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. What are your conclusions and recommendations regarding Black Hills Kansas' Application and the related approvals being requested in this case?

A. Based on my review of the Application, of responses to data requests propounded by the parties, and of other documentation, my conclusions and recommendations are:

- The Company's proposal is not a gas hedging program, it is investment program.
- The Company's affiliate, Black Hills Exploration and Development, Inc. ("BHEP"), currently holds gas reserves sufficient to meet the requirements of the COSG Agreement.
- The Company's parent, Black Hills Corporation ("BHC"), could use the program as a mechanism to rehabilitate the financial condition of BHEP and enhance earnings for BHC's shareholders.
- The proposal unfairly transfers nearly all of the economic risk of gas production to ratepayers without reasonable compensation for bearing that risk.
- The proposal improperly guarantees COSGCO total cost recovery and a minimum return on equity while offering ratepayers only the possibility of lower costs once COSGCO's claims are satisfied.
- If BHC believes an affiliate can produce below-market priced gas through existing

production assets, then it should be willing to offer Black Hills Kansas a long-term gas supply contract at a fixed price, which would provide ratepayers with rate stability while mitigating BHEP's market risk.

- As currently outlined in the COSG Agreement, the proposal to acquire gas reserves for up to 50% of the Company's firm gas demand is not in the best interest of Kansas ratepayers and should be denied.

IV. OVERVIEW OF THE APPLICATION

Q. Please summarize the corporate structure of BHC and its subsidiaries.

A. As noted on page 2 of the Application, BHC serves approximately 765,000 electric and gas customers in the Midwest, including gas utility customers in Kansas, Wyoming, Nebraska, Iowa and Colorado and electric utility customers in South Dakota, Wyoming and Colorado. The regulated services are provided through a series of limited liability companies, including Black Hills Kansas, which are held by BHUH. In addition, BHUH currently acts as a purchaser or purchasing agent for the various gas utilities. BHC is also in the oil and gas exploration and production businesses through its subsidiary, BHEP. In Kansas, Black Hills provides retail gas service to 112,000 customers in 48 counties.

Q. Please provide an overview of the terms of the COSG Agreement.

A. Under the terms of the COSG Agreement, BHUH, through COSGCO, would acquire gas reserves that meet various criteria as set forth in the COSG Agreement. The reserves would provide up to 50% of the utilities' forecasted firm demand.[1] COSGCO is expected to sell all of the developed gas and associated liquids to third parties, rather than deliver gas to Black Hills Kansas or other utilities. (Although there are provisions in Article 3 of the Agreement that would allow BHUH to purchase the gas for the utilities.) The Company claims that the sale of the gas to third parties maximizes federal tax advantages that are more favorable to production companies that are not integrated from gas in the ground to burner tip. The hedging aspect of the transaction is captured in the hedge costs and hedge credits that would be passed on to Black Hills Kansas based on COSGCO's revenues, expenses and rate of return (adjusted for a 100 basis point dead band around the equity portion of the return). If the revenue from the gas (and associated liquids) exceeds all the costs of production, including the allowed rate of return plus 100 points on equity, then the ratepayers will receive the excess revenue in the form of a hedge credit to be passed through the gas adjustment clause. Stated simply, COSGCO will have to over-earn by more than 100 basis points on equity before ratepayers would see any reduction in the cost of gas in their utility bills. If actual production revenues fall short of COSGCO's total costs, including its cost of capital, then ratepayers would be responsible for making up the shortfall to COSGCO, including any shortfall in return up to 100 basis points below the approved return on equity. This shortfall would be made up in the form of additional hedge costs to be included in the gas adjustment clause. This provision ensures that COSGCO will recover its costs and will earn within 100 basis points of its return on equity.

1 Or a revised percentage as determined by the Commission.

Q. How does the Company propose to determine the targeted rate of return on the investment in the gas reserves?

A. Black Hills Kansas is proposing that the return on equity be based on the average of the annual returns on equity for all gas and electric utility rate cases for the calendar year, as reported by Regulatory Research Associates, unless there are fewer than twenty reported gas and electric utility cases for that year. In that case, the Company proposes to use a two-year average of reported returns. In addition, the costs recovered under the COSG Agreement would include a return on equity based on a capital structure consisting of 60% equity, regardless of the actual capital structure of the underlying utility or of COSGCO.

Q. What criteria would BHUH utilize to acquire reserves?

A. As discussed in the testimony of Mr. Vancas at pages 14-15, the reserves would consist of fields with proven reserves and an operating history that establishes to some extent the drilling and operating costs for those reserves. Reserves are to be located in fields with connections to interstate pipelines or in fields for which production and transportation costs can be "reliably" estimated. In addition, the acquisition, development and production of the gas from the reserves would be forecast to be less, on a net present value basis, than the long-term forecast of natural gas prices.

Additional criteria discussed by Mr. Carr on page 9 of his testimony include:

- The reserve area must be located in the Rockies or Mid-Continent regions and must contain geologic formations that have well-established histories of production.

- The reserve must be anticipated to contain, on a Btu content basis, at least 50% natural gas (methane).
- The property must have a remaining life of at least fifteen years.
- A reserve must have proved developed producing ("PDP") reserves of at least 50% of its net present value.

Q. What oversight does the Company propose for the reserves to be acquired pursuant to the COSG Agreement?

A. The COSG Agreement has oversight provisions that require an independent third party Hydrocarbon Monitor to review a proposed reserve acquisition or drilling plan to determine whether or not it meets the requirements set forth in the COSG Agreement. It should be noted that the monitor is not required to find that the proposed acquisition is the best choice available, but only that it meets the criteria set forth in the Agreement. Every five years the monitor will also assess COSGCO's future drilling plans to determine whether or not they also meet the terms of the Agreement. A third-party Accounting Monitor will also be retained to confirm that the calculations of the hedge costs and hedge credits are accurate. The monitors, subject to Commission approval, will be hired and paid for by the Company and their costs will be recovered through the revenue requirement of the COSG Program. In addition, each potential acquisition would be subject to Commission review to determine if it meets the criteria in the COSG Agreement, based on an expedited (60 day) approval process.

Q. What is the stated term of the COSG Agreement?

A. As referenced on page 25 of Mr. Vancas's testimony, the COSG Agreement would run until the wells on the acquired properties had been plugged and abandoned, and the property reclaimed. Thus, the COSG Agreement would continue to be in effect even after the wells stopped producing gas. Black Hills Kansas states that the typical life of a gas well is at least 20 years. Therefore, the COSG Agreement would be expected to be in effect for at least a 20-year period.

Q. What is the goal of the COSG Program?

A. As stated on page 14 of Mr. Vancas' testimony, Black Hills Kansas contends that the goal of the program is to minimize ratepayers' exposure to gas price volatility and provide long-term price stability through a physical hedge (owning gas reserves), while providing an opportunity for ratepayers to pay less than market price for up to 50% of their natural gas requirements. Because gas prices have historically been volatile from year-to-year, and are now at what the Company believes to be a historic low cost, Black Hills Kansas states that it believes now is a good time for ratepayers to invest in gas reserves.

Q. How much flexibility does the Commission have with regard to its review of the Company's Application?

A. Black Hills Kansas and its affiliated utilities are seeking regulatory approval for the COSG

Agreement in a total of six regulatory jurisdictions. Because of the number of jurisdictions involved, it is not possible for individual states to modify the proposed COSG Agreement in any meaningful way. Thus, while the Commission has the ability to make minor changes, such as changing the percentage of the forecasted annual demand to be hedged on behalf of Kansas customers, the Company's proposal is largely a take it or leave it proposition.

V. DISCUSSION OF THE ISSUES

Q. Is the COSG Agreement a "Physical Gas Hedge Contract", as claimed by Black Hills Kansas in its Application?

A. No, it is not. The proposed COSG Agreement does not provide Black Hills Kansas with physical gas or with gas at a fixed price, as suggested by the term "Physical Gas Hedge Contract". In fact, pursuant to the COSG Agreement, BHUH will sell the gas procured under the program to third parties. Moreover, BHUH will continue to procure gas for Black Hills Kansas in the same way that it does today. In addition, the price paid for gas procured for Kansas ratepayers will be unaffected by the COSG Agreement. While the COSG Agreement will not change either the gas procurement process or the price of gas used to provide service in Kansas, it will put the Kansas utility in the business of gas exploration and development, and will require Kansas ratepayers to pay all of the costs of that business, including an excessive return on equity, with the hope that BHUH can effectively beat the market, in which case ratepayers will share in any excess profits. I believe that this is a bad deal for ratepayers, and presents ratepayers with high risk in return for a relatively small reward.

A. Ratepayer Risk

Q. Please list and describe the risks that will be borne by ratepayers if the Kansas Commission authorizes Black Hills Kansas' participation in the COSG Agreement.

A. Under the terms of the COSG Agreement the ratepayers bear 100% of the economic and operating risks of the proposed gas production and sales activities to be carried out by COSGCO on behalf of BHUH. In addition, ratepayers bear almost 100% of the risk associated with financing the gas exploration activities, including a return on equity that is not subject to Commission oversight and that is based on an artificially high percentage of equity in the capital structure. Kansas ratepayers will bear the risk associated with guaranteeing the Company a minimum return on its investment, the risk of flat or falling market prices for natural gas, the risk of guaranteeing full recovery of all of the Company's expenses, regardless of prudence (including the cost of drilling dry holes), the investment risk inherent in all assets acquired, the risk of incorrect long term price forecasts, the risk of force majeure events including terrorism and changes in law, and other risks.

Q. Please describe how the Company is guaranteed to earn a minimum return on its investment.

A. The Agreement provides in Article 5 for a calculation of a hedge cost in the event that COSGCO does not fully recover all of its costs and earns less than 100 basis points below its allowed return on equity. The allowed return on equity at the time of the filing, based on the average of the prior year's authorized returns awarded to electric and gas utilities, was 9.86%, according to the testimony of Mr. McKenzie at page 3. Assuming no change in the benchmark return on equity, ratepayers would be required to guarantee that the COSG Program would earn 8.86% on equity *at a minimum*, or approximately 90% of COSGCO's targeted return on equity. This provision is so onerous and unfair to ratepayers that the Commission should deny the Application on this basis alone. Utilities are given the opportunity to earn their authorized rate of returns, not a guarantee. The return on equity provisions of the COSG Agreement effectively provide a guaranteed return to BHC that will be the responsibility of Kansas ratepayers, regardless of operational results.

If the Commission were to guarantee any minimum return on equity, the Commission should recognize that the COSG Program provides virtually no risk to BHC and should therefore establish a return on equity that reflects a risk-free rate. In this case, it would be more appropriate for the Commission to authorize a return on equity that is closer to the debt rate than to the authorized returns for other electric and gas utility companies that do not have cost recovery guaranteed from their ratepayers.

Moreover, under the Company's proposal, the Kansas Commission has no input into the benchmark return on equity that ratepayers would be required to pay. That is because the COSG Agreement provides for the return on equity to be based on returns on equity awarded in other states. In addition, the benchmark return on equity would be based not only on gas returns awarded by other state commissions, but on electric returns awarded by other state commissions as well. The result is that that gas costs paid by Kansas ratepayers under the

COSG Agreement would depend, in part, on return on electric equity awards made in 49 other states.

Q. Do you believe the capital structure utilizing a 60% equity investment is reasonable?

A. Adding even more insult to injury is the provision that the capital structure used to develop the overall rate of return would include 60% equity. This is a very high equity component relative to a typical utility's capital structure. For example, a return on equity based on a 9.86% return on equity and a 60% equity percentage would yield a return on equity of 11.83% if the actual capital structure contained 50% equity. The capital structure authorized in Black Hills Kansas' last base rate case contained 50.34% equity.

Moreover, Mr. McKenzie demonstrates on Exhibit AMM-7 that the combination electric and gas companies used to develop the illustrative benchmark return had an average equity ratio of 48.3% at the end of fiscal year 2014 and a projected equity ratio of 49.1%. The proposed 60% equity ratio proposed in the Application therefore exceeds the referenced utilities' 48.3% average equity ratio by 11.7 percentage points, for an increase of almost 25% over the existing use of equity by the utility companies. This is an enormous increase in the proportion of equity, and would result in a substantial windfall for shareholders, especially considering the return on equity is largely guaranteed to be recovered from ratepayers through the provisions of the COSG Agreement.

Q. Please summarize your concerns regarding the return on equity provisions of the COSG

Agreement.

A. The COSG Agreement raises serious concerns with regard to a cost of equity that is a) guaranteed by ratepayers, b) primarily based on the decisions of regulatory commissions other than the Kansas Commission, c) based on electric returns as well as gas returns, and d) artificially inflated due to an excessive percentage of equity in the capital structure. Therefore, under the terms of the COSG Agreement, the risk that the COSG Program will fail to earn its minimum return of equity (set at approximately 90% of its benchmark return) will be improperly transferred from shareholders to Kansas ratepayers. The shareholders should bear this earnings risk, since the shareholders are ultimately responsible for management of the operation and can demand changes in management if financial results are not up to expectations. The ratepayers have no such influence on management or on operational results, and therefore should not be a captive cash cow as they are under the proposed COSG Agreement.

Q. Do you also have concerns about the cost of debt component in the COSG Agreement?

A. Yes, I do. In addition to guaranteeing a return on equity, Kansas ratepayers are also being asked to guarantee the return on debt associated with the COSG Program, even though the actual debt costs are unknown at this time. The definition of "Allowed Cost of Debt" contained in Article 1 of the COSG Agreement indicates that COSGCO may issue its own debt to finance its production program. This might prove to be more expensive debt than the debt costs used to set regulated utility rates for Black Hills Kansas. Moreover, there is no incentive for COSGCO to take steps to minimize its debt costs, since all costs including the return on debt will be guaranteed by Kansas ratepayers.

Q. Why would flat or falling gas prices be a risk for ratepayers under the terms of the COSG Agreement?

A. Ratepayers will only benefit from the COSG Agreement if COSGCO earns more than 100 basis points in excess of its benchmark return on equity. Therefore, if gas prices stay low or flat over much of the twenty-year term of the COSG Agreement, there is the possibility that COSGCO will not be able recover all its production and investment costs through the sale of gas. In that case, ratepayers will not see any benefits in the form of hedge credits that would reduce their cost of gas, despite bearing all of the economic and operating risks of the investment.

A great deal of the Company's testimony is presented arguing that this point in time, with relatively low gas prices, provides an opportunity for investment in gas reserves. But the opportunity for an investment does not guarantee that this investment will be a good deal for ratepayers, especially not under the lopsided risk sharing provided for in the COSG Agreement. Despite the current relatively low gas prices, a further reduction in price is not ruled out by the U.S. Energy Information Administration. One of its current alternative scenarios calls for an initial decline in gas prices from 2015 to 2020, then a modest price increase of less than 2% over the twenty-five year long-term price forecast.[2]

The website for U.S. EIA states:

> In the AEO2015 alternative cases, the Henry Hub natural gas spot price is lowest in the High Oil and Gas Resource case, which assumes greater estimated ultimate recovery per well, closer well spacing, and greater gains in technological development. In the High Oil and Gas Resource case, the Henry Hub natural gas spot price falls from $3.14/million Btu in 2015 to $3.12/million Btu in 2020 (36% below the Reference case price) before rising to $4.38/million Btu in 2040 (44% below the Reference case price). Cumulative U.S. domestic dry natural gas production from 2015 to 2040 is 26% higher in the High Oil and Gas Resource case than in the Reference case and is sufficient to meet rising domestic consumption and exports—both pipeline gas and liquefied natural gas (LNG)—even as prices remain low.

The front page of the Saturday, January 16, 2016 New York Times describes just a glut of oil on the world markets and notes that it may take years to work through the inventory "that is being warehoused, poured into petroleum depots or loaded onto supertankers for storage at sea." The NY Times reported that the oil glut was cited as a factor causing global stocks to sink as investors worried about slackening demand from China. A spokesman for an Oklahoma drilling company, Latshaw Drilling, is quoted as saying "the glut is the 800-pound gorilla in the room." My point here is that we are in somewhat of an energy revolution and no one can know with confidence whether gas prices will even go up or down. Even flat or modestly increasing gas prices may well prove very costly to consumers under the COSG Agreement. Yet the uncertainty and risk of changes in gas prices is 100% assigned to the

2 This information is shown at https://www.eia.gov/forecasts/aeo/executive_summary.cfm.

ratepayers under the COSG Agreement.

Q. Please explain how ratepayers bear the risk for all operating and maintenance costs under the proposed COSG Agreement.

A. Under the terms of the Agreement, ratepayers guarantee COSGCO dollar-for-dollar recovery of its actual operating and maintenance costs pursuant to the calculation of the Hedge Settlement in Article 5. The definition of operating expenses in the Agreement at Article 1 is as follows:

> 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, 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%).

Thus, under the COSG Agreement, ratepayers are responsible for all costs, including the costs for evaluating "potential properties". BHUH could incur substantial costs over the next several years researching various properties in which COSGCO never invests, all at the expense of ratepayers. COSGCO costs will also include marketing expenses related to selling the gas that is produced on the open market. Many of these costs may also be paid to BHEP affiliates, providing a further benefit to BHC and its subsidiaries at the expense of regulated ratepayers in Kansas.

It should also be noted that there are no provisions for Black Hills Kansas or for the Kansas Commission to challenge the amount or prudency of actual expenditures incurred by COSGCO. Thus, the Commission must trust that COSGCO will be well managed over a twenty-year period with no oversight over its costs, and with very little incentive for COSGCO to control its costs, given the guaranteed recovery from ratepayers.

Q. Are the ratepayers bearing the investment risk of all of COSGCO's assets as well?

A. Yes, 100% of the risk of the Investment Base (defined in Article 1) is assigned to the ratepayers. Ratepayers will be responsible for 100% of the return <u>of</u> this investment, regardless of whether any gas is produced from the properties. In addition, as previously discussed, ratepayers will also be responsible for guaranteeing a minimum return <u>on</u> the equity (within 100 basis points of the benchmark return) used to finance this investment, based on a hypothetical capital structure consisting of 60% equity.

This investment risk includes not only the risk inherent in normal operation of the production facilities, but also the risk of extraordinary events that could impact the production of gas. Section 9.4 of the COSG Agreement, Force Majeure, makes it clear that ratepayers bear the burden even of labor difficulties, lockouts and strikes, as well as all manner of natural or man-made disasters, including terrorism or changes in law, that affect the value of the investment in gas production. Section 9.4 states as follows:

> **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, lightening, 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 (sic) 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.* (emphasis added)

The risk of a change in law that could impact permits or the use of specific technologies is a very significant risk included in Force Majeure that would be borne by Kansas ratepayers. The response to data request CURB-77 confirms that costs associated with changes in regulations regarding the development and operation of COSGCO properties would still be the responsibility of ratepayers under Article 5 of the COSGCO Agreement. Responsibilities of the parties under Article 5 will not be suspended for any reason, including Force Majeure events. Therefore, ratepayers are obligated under the COSG Agreement to pay all costs, including a return on equity, for what might become useless assets. Once a property is acquired, Kansas ratepayers would have no alternative but to guarantee recovery of all costs, regardless of whether that property actually produces gas. This protection is far beyond any guarantee that regulated utility companies currently enjoy, as utility company assets are generally required to meet a "used and useful" standard in order to be included in regulated gas rates, not only in Kansas but elsewhere.

Q. Please explain how ratepayers bear the risk of gas production volumes that may differ from forecast.

A. In addition to ratepayers bearing the entire risk of investment in assets that are not used and useful, such as dry holes or assets that are shut-down for any reason, Kansas ratepayers would also be responsible for production under the COSG Agreement even if the price of gas fell below production costs. The Company made it clear in response to data request CURB-67 that COSGCO would continue to produce gas from its existing wells, even if the price of the gas fell below its production cost.

Q. What is Black Hills Kansas' percentage share of the operating costs and investments that will be incurred by COSGCO?

A. Black Hills Kansas' currently-anticipated share of the total costs under the COSG Agreement is 17.91%, as shown at Exhibit C of the Agreement. But that share is based on the participation of each of the seven other utilities listed in Exhibit C. To the extent that some of the other regulatory jurisdictions do not authorize their utilities to participate in the COSG Program, then the percentage of costs allocated to Black Hills Kansas' ratepayers may be higher. Thus, the overall costs allocated to Kansas will depend upon the regulatory decisions made in other BHC regulatory jurisdictions.

Q. Does the requirement that COSGCO engage a third-party Hydrocarbon Monitor and an Accounting Monitor reduce some of the risks borne by ratepayers?

A. Ratepayers do bear a risk that COSGCO might fail to comply with the criteria set forth in the COSG Agreement for selecting and developing the gas reserve properties. Ratepayers likewise bear a risk that the charges allocated under the COSG Agreement will not be accurately calculated or allocated. The third party monitors are provided for in order to minimize those risks. However, there is a concern that monitors may not be truly independent, and even if they are, that their roles are severely limited and the time constraints under which they operate make it unlikely that they will provide meaningful protection to the ratepayers.

Q. Please explain why you believe there is a risk that the monitors appointed as a consumer protection may not prove to be truly independent?

A. The Hydrocarbon and Accounting Monitors will be retained and paid, subject to Commission approval, by BHUH. Therefore, especially over time, these monitors are likely to establish a stronger working relationship with their BHC clients than with the numerous utility commissions in the various state jurisdictions. It may be difficult for the monitors to retain true independence under these circumstances.

However, even if the monitors do maintain their independence, they will be operating under severe time constraints that may affect their performance. Section 2.2 of the COSG Agreement addresses the duties of the Hydrocarbon Monitor to assess whether each proposed acquisition satisfies the acquisition criteria, whether the drilling plans satisfy the drilling criteria and whether the reserves reported in BHUH 's annual report to the utilities were calculated in accordance with standard industry practice. If the Hydrocarbon Monitor finds that COSGCO did not adhere to standard practice, then a third party reservoir engineer will be retained to resolve the difference in opinion. It is important to note that the Hydrocarbon Monitor does not do any independent investigation of the proposed acquisition, per Section 4.2 of the Agreement. The Hydrocarbon Monitor's job is solely to review the data and reports that BHUH provides to it. The Hydrocarbon Monitor will receive a summary of geologic and geophysical data, the price and terms of the proposed acquisition, a drilling plan of at least five years' duration, historic production data, forecasted production data, operating and capital cost forecasts, a long-term market price forecast, and other cost data. But the Hydrocarbon Monitor only has ten calendar days, per Section 4.3, to review this data and to issue a written report to BHUH, the various participants, and each regulatory jurisdiction. Therefore, the Hydrocarbon Monitor will have between 6-8 working days to review all of this material and to prepare a report to the various parties. Given the volume of materials the Hydrocarbon Monitor is expected to review, it is apparent that no independent in-depth investigation by the Hydrocarbon Monitor is possible. Moreover, the COSG Agreement provides for expedited reviews by the various state regulatory commissions within 60 days. If the COSG Agreement is not specifically rejected by a regulatory commission, then ratepayers will be committed to a five-year drilling and development plan, which will result in wells and other production assets that themselves will have a life expectancy of approximately twenty-years. Article 6 requires the terms of the COSG Agreement to remain in effect until all wells "have been plugged and abandoned and the portions of the Properties affected by such wells reclaimed in accordance with applicable law…."

Importantly, Section 4.3 provides that if one or more regulatory commissions reject the acquisition or drilling plans, BHUH can still direct COSGCO to proceed "without further PUC [regulatory commission] action". Further, Section 4.3 (i) of the Agreement provides that, if BHUH elects to proceed without the participation of all of the regulatory commissions, it has the right to modify the proposed drilling program, as long as the Hydrocarbon Monitor finds that the acquisition, with the revised drilling plan, still meets the acquisition criteria. The right of BHUH to modify the drilling plan is at its absolute option, and can occur at its discretion *without further PUC action*. Presumably any such adjustment to the drilling plan would affect the likely cost to the ratepayers, as COSGCO's fixed costs would be spread over a reduced volume of gas. In such circumstances, the Kansas Commission would have agreed to an gas reserve acquisition without knowing the actual drilling plan, its costs, or the jurisdictional share of allocated costs. In the end, this diminishment of regulatory commission oversight is a major risk borne by ratepayers. This provision suggests that the ultimate cost to Kansas ratepayers may not be known until the last regulatory commission acts, resulting in some commissions' making a determination without knowing what its state's ultimate share of the costs will be.

Q. Does the COSG Agreement insure that the ultimate level of costs allocated to each state is reasonable?

A. No, it does not. Under Section 5.5 of the COSG Agreement, each year the Hydrocarbon Monitor will assess whether COSGCO's reported reserves were calculated in accordance with industry practice and the Accounting Monitor will prepare an assurance report regarding the accuracy of the calculations made by COSGCO. However, these assessments are not intended to evaluate the reasonableness of the underlying costs, but only to verify that the underlying costs were calculated properly. There is no provision in the COSG Agreement for the regulatory commissions, or other parties, to evaluate the reasonableness of the underlying costs. Accordingly, if the COSG Agreement is approved, the Kansas Commission will be committing ratepayers to a long-term investment without any ability to assess the underlying costs charged to ratepayers and without the ability to insure the reasonableness of those costs over the term of the COSG Agreement.

Q. Would the regulatory commissions or the utility companies have access to the court system if they have unresolved disputes with BHUH or COSGCO under the terms of the Agreement?

A. No they would not, and therefore the ratepayers would not have recourse to the courts either. All disputes will be resolved, per Section 9.3(ii) of the Agreement, by arbitration in Rapid City, South Dakota before just one arbitrator. Rapid City, South Dakota is home to the headquarters of BHC and that fact would seem to favor BHUH, at least in terms of logistics, in the event that such arbitration were to take place.

Q. Can any party assign or transfer any of its rights or obligations under the provisions of the COSG Agreement?

A. No, only BHUH can unilaterally assign its rights without written consent of the other parties. Under Section 9.5 of the COSG Agreement, BHUH has the right to execute a change in control or sell substantially all of its assets to a third party. Thus, the Agreement contemplates a circumstance whereby the utilities could enter into a COSG Agreement with BHUH and shortly find themselves dealing with an entirely new entity who may have purchased BHUH or substantially all of its assets (presumably including COSGCO). This is another example of risks passed on to ratepayers without any consideration given in compensation for bearing such risk.

Q. Do the termination provisions is Article 6 of the Agreement help to limit the risk to ratepayers?

A. The COSG Agreement provides that if an early termination is ordered by one of the regulatory commissions, then the terminating utility is responsible for an "Early Termination Amount", as defined in Section 6.4. Therefore, while there is a provision for early termination, ratepayers would still retain much of their financial responsibility under the COSG Agreement, including the repayment of the investment allocated to that jurisdiction.

Q. Please summarize your discussion of risks borne by the ratepayers pursuant to the COSG Agreement.

A. Ratepayers bear all operational and investment risk of the gas exploration and drilling activities to be conducted by BHUH and COSGCO under the terms of the COSG Agreement. The allocation of 100% of these operational and investment risks persists in all circumstances, including under force majeure events (broadly defined to include even labor disputes). The obligations of the ratepayers to pay for any and all costs, including a return on equity, through the gas adjustment clause will persist for a period of up to twenty years or more, until all the wells and production sites have been fully remediated, even if no gas is ever produced by COSGCO. The provisions in the COSG Agreement requiring a Hydrocarbon Monitor and an Accounting Monitor, provide only very limited protections to ratepayers. Ratepayers bear all the risk of declining, flat, and modestly increasing gas prices. The Company however is guaranteed a minimum return on equity in all circumstances, at the expense of utility ratepayers. And BHUH can be acquired during the term of the Agreement, or sell substantially all of its assets. In return, ratepayers may receive some credits from gas sales that would effectively reduce their cost of gas. On balance, I believe that this arrangement is a bad deal for ratepayers and would commit ratepayers to many years of uncertain costs while guaranteeing long-term profits for shareholders.

B. Affiliated Interest Issues

Q. In addition to your concerns regarding the risks that the COSG Agreement would place on ratepayers, do you have other concerns about the Company's Application?

A. Yes, I do. I am very concerned that BHUH will ultimately propose to acquire the existing BHEP assets for the program, as a means of propping up these troubled businesses. In my opinion, the COSG Program is being driven largely by the desire of BHC to monetize assets that have been underperforming and putting downward pressure on corporate earnings.

Q. Please explain why you are concerned that BHUH may propose that COSGCO acquire BHEP's assets as part of this program.

A. There is ample evidence that BHC is seeking to monetize its underperforming gas reserve assets in Mancos shale in the Piceance basin by including them in utility-related cost of service gas operations as proposed in the Application. At the October 8, 2015 BHC Analyst Day Presentation, BHC Chairman, President, and CEO David Emery stated that:

> But oil and gas prices have had a pretty big negative impact on us. And as I said, that being our one kind of market-exposed business, it's hit us pretty hard. You look at the operation losses at E&P [Exploration and Production] this year, and they're not good. You know, we've had a non-cash impairment of our reserves, and likely we'll have more as the year goes on. But, for a strategy perspective, <u>I think we've remedied that for a go-forward strategy, and really focusing on cost of service gas instead, and it really kind of gets us out of that very heavy dependence on product prices</u>. (emphasis added)[3]

The "cost of service gas" strategy discussed by Mr. Emery is the program that is the subject of

3 BHC Analysts Day Transcript, page 5.

this Application, i.e., the plan to force regulated ratepayers into investments in the gas production business, and the corresponding guarantee to shareholders of certain returns on equity. At the October 8, 2015 presentation, Mr. Emery went on to state:

> Cost of service gas program is something we've been talking about for a couple of years - - really, more like three or four. You saw that in the last month we filed in five of our six states. We'll file in the sixth one soon and we'll fill you in on that. Obviously, oil and gas is something that we've made a pretty major transition of what we're trying to accomplish there this year, and that is a much greater focus on utility cost of service gas and a pretty dramatic reduction in regular E&P spending.[4]

Brian Iverson, Regulatory and Assistant General Counsel, described the program for the analysts, stating:

> So…what the filings really cover…is a…prepackaged set of determination of, how does the relationship work between a non-regulated affiliate that's going to down the resources, and the utilities that are going to basically get the benefit of the resource? And so, what we've done is provided new tariffs for the Commission to review. We've provided mechanisms on how we would transfer property into that and set up a more timely process to go through, with a 60-day window to, once we identify a property and have it turned into the Commission, for there to be an approval process, so that we can move assets into that. Those assets could include some of our Piceance Mancos assets could include some third party assets too.[5]

Mr. Iverson went on to tout the program as a "win-win", that provides "a stability of cost for customers, but also provide a great investment opportunity for utilities."

4 Id., page 2.

Q. Does BHC have sufficient gas assets to provide all of the investment that would be needed for the proposed program?

A. Yes, it does. As discussed by Mr. Iverson,

> About 75 Bs is our actual gas supply. And what we've proposed in the filings is that we would use – we're suggesting that we work to get up to half of the supply through this program. And so, that's that 37.85 number you see on there.
>
> So, to give you an idea of an order of magnitude, you know, one of the assets we've talked about transferring over into this, or using it – this is the Mancos. You know – and the other piece you look is that 37 Bs a year – if you look at the potential resource that we have in the Mancos, still leaves plenty of other resource out there. That's just a fraction of what -- the resource we have in the Mancos itself. So, to look at, can you do this program; how do you get it done, there's plenty of gas out there to make it work.[6]

Thus, BHC's has more than enough gas investment to supply all the assets proposed for the COSG Program. As further discussed by John Benton, Vice President and General Manager of Oil & Gas:

> In summary, our results to date in the Piceance continue to support the resource potential of between 2 and 4 Tcf. Our current project --projected demand for our cost of service gas program --I think Brian alluded to this in his presentation --somewhere between 37 and 38 Bcf a year. What that means is, a 20-year program for cost of service gas only requires about ¾ of a Tcf. That leaves us with a lot of additional resource potential to support expansion of the program; some non-regulated development potential to bring in other utility companies into the program; or, some partial monetization of the asset. So, a lot of available opportunity there. We believe that it has great potential for the cost of service gas program and we think the results to date support that belief. While the drop in product prices

5 Id., page 13.
6 Id., page 16.

> has not favored the profitability of our current projects, we have made significant changes to the program to adapt to that changing market. [7]

Given the foregoing, it seems that in all likelihood, these Piceance shale assets are the very reserves that will be brought forth as an acquisition candidate for Commission approval if the COSG Agreement is approved. But by the time the acquisition is actually proposed to the Commission, the only standard for evaluating the proposed affiliated interest transaction, because of prior approval of the COSG Agreement, will be whether or not it meets the criteria set forth in the Agreement. COSGCO would not be required to demonstrate that a proposed acquisition is the best available investment, only that it is good enough to meet the criteria in the COSG Agreement. The lack of transparency concerning this issue is inexcusable, and is sufficient reason in itself for the Commission to deny the proposed Agreement.

Q. Why are affiliated transactions of particular concern?

A. Transactions between a utility company and non-regulated affiliated companies always pose a special risk in that the ratepayers do not have the assurance that the price of affiliated transactions is comparable to the price that would be paid to an unaffiliated third-party. With affiliated transactions, there is always a concern that the consolidated entity has an incentive to maximize costs to regulated ratepayers, thereby subsidizing unregulated businesses and/or providing excessive profits to shareholders. For this reason, a standard regulatory safeguard exists that requires transactions between a utility company and its non-regulated affiliate to be

7 Id., page 29.

priced at the *lower of cost or market* price. But if the Kansas Commission approves the COSG Agreement, it is approving an investment acquisition made at market prices, even though that acquisition may be executed between affiliated entities.

Q. Would BHC be willing to transfer assets to COSGCO at the lower of cost or market price?

A. In response to a question on transfer pricing at the October 8, 2015 Analyst Day Presentation, Mr. Iverson stated that pricing any assets transferred into COSGCO would be based on "a formula that we use to – basically, an evaluation with, you know, engineers and a financial present value. You know, it's a future (inaudible) kind of cash flow kind of analysis that we do. So, it wouldn't necessarily be the book value on our – of our assets."[8]

The response to data request CURB-45 indicates that BHC has no intention of transferring assets to COSGCO at the lower of cost or market, even though COSGCO will exist solely as a vehicle for transferring costs to regulated utility ratepayers. The response to CURB-45 states: "If the Piceance is the proposed property, the intention would be to transfer it at market value, in the ordinary course of business. The selling affiliate could have a profit or loss based upon the transfer price to COSGCO when compared to its own book value."

While transactions among non-affiliated parties are presumed to be at arms-length, and therefore there is a presumption that such transactions are priced at market, no such presumption exists with regard to affiliated transactions. Moreover, in this case, BHC would have an incentive to maximize the “market price” paid by COSGCO for affiliated assets, since ratepayers will be guaranteeing the return of the initial investment as well as the return on equity that these assets are permitted to earn for shareholders.

When asked directly if it would be willing to transfer Piceance assets to COSGCO at book value in data request CURB-50, the Company responded unequivocally "No, the Company would not be willing to transfer its Piceance assets to COSGCO for book value." It goes on to state in this response that any transfer would have to meet the acquisition criteria in the COSG Agreement. This serves as a cautionary note for any commission considering approval of the COSG Agreement, as any jurisdiction that does approve the Agreement will forfeit the usual ratemaking protections put in place concerning affiliated interest transactions. As addressed on page 5 of Mr. Vancas’s testimony, the Application specifically seeks waivers from any affiliate rules or regulations or ring-fencing commitments that would be necessary for the Commission to grant approval of the Agreement. Such waivers could eliminate very significant ratepayer protections, and would grant the Company unprecedented ability to set prices and charges among its affiliates without any regulatory review.

C. Impact on Current Hedging Strategy

Q. Please discuss the current hedging strategy in Kansas.

A. While the specific details of the Company’s gas hedging program are confidential, hedging is currently undertaken based on a statewide approach utilizing options, as discussed in the

8 Id., page 17.

response to data request CURB-106. Moreover, according to that response, "The purpose of options in Kansas is not based on a percent of the portfolio, but rather a targeted dollar amount per customer per year. This approach was implemented following customer surveys. In addition to options, BHUH makes use of available contract storage service on Kansas pipelines, which approximated 10-15% of annual demand in the past five years." Given that the current hedging program was part of a statewide initiative, the Commission should not permit the Company to abandon its current hedging strategy without a full investigation of the impact of the current program and a full evaluation as to whether the current statewide hedging strategy should be terminated. The COSG Program represents a dramatic departure from the statewide hedging strategy that is currently in place. This aggressive program, which would result in up to 50% of gas demand being "hedged" for a period of approximately 20 years, strikes me as overly aggressive, particularly when one considers the long-term financial guarantees which would accrue to shareholders as a result of this program. If the Commission believes that some modification of its statewide hedging program is appropriate, I would recommend that it investigate a pilot program that is much more modest in scope without a massive commitment to just one specific course of action, especially since that course of action involves the use of troubled and underperforming assets owned by the Company's unregulated affiliate.

Q. Has any other regulatory jurisdiction adopted a program such as the COSG Program proposed in the Application?

A. No, it has not. While Mr. Vancas discusses long-term gas supply arrangements in several other jurisdictions around the country at pages 12-13 of his testimony, each of these arrangements has its own characteristics that differ from the COSG Program proposed in this case. The response to data request CURB-1 states that "The Company is unaware of any state regulatory commission that has approved a program identical to that proposed." There is no precedent in other jurisdictions that is applicable to the COSG Agreement proposed in this filing, whereby the regulatory commission is being asked to bind ratepayers to a long-term agreement that would guarantee recovery of all costs, including a return on equity, and which is likely to include affiliated assets at unknown "market" prices.

Q. If BHC believes that it can operate gas production assets more effectively than the market, how could it modify the proposed COSG Agreement to make it more equitable for ratepayers?

A. If BHC wants to lock in a market for its gas assets, and it believes that gas prices are likely to rise in the future, then it could offer Black Hills Kansas a traditional gas hedging arrangement, whereby it offers to sell gas to Black Hills Kansas for a long-term duration at a fixed price. Such an arrangement would still put ratepayers at some risk of paying higher than market prices for gas over the long-term, but it should also mitigate gas price volatility and present the Commission with a known financial structure that could then be evaluated for reasonableness. In this way, BHC would have a ready market for some of its gas assets, but it would also have an incentive to manage those assets efficiently and to minimize the associated costs. If BHC were successfully, then shareholders would enjoy the earnings and BHC would no longer be at risk to market this gas. Ratepayers would also enjoy a known commodity price over the long-term. This is a much more balanced arrangement then the lopsided proposal contained in the Application, whereby ratepayers take on all of the risk for the potential of a relatively small reward.

VI. CONCLUSION AND RECOMMENDATION

Q. Does the COSG Agreement provide a reasonable balance between the interests of shareholders and ratepayers?

A. No, it does not. The only risk the COSGCO bears under the COSG Agreement is that it may earn 100 fewer basis points on equity than it hopes for (although even that risk is offset by the fact that it retains 100% of the first 100 basis points of any excess earnings). Under the COSG Agreement, COSGCO is guaranteed to earn approximately 90% of its benchmark equity return and to recover all of its expenses, including 100% recovery of its investment. BHC is proposing a virtually risk-free arrangement for shareholders, with preapproved terms and conditions, even though it cannot provide any specifics with regard to acquisition of projects or associated costs. COSGCO can confidently propose any acquisition knowing that the COSG Agreement has protected shareholders and holds them harmless from any possibility of financial loss. If the risk sharing were reversed, and shareholders bore 100% of operating costs, investment and volume risks, all for a return calculated to match an industry average, BHC would surely walk away. In fact, it appears that this is exactly what BHC may be trying to do – transfer the risk of BHEP current unregulated investments in oil and gas exploration from shareholders, where it properly belongs, to ratepayers.

Q. What is your recommendation concerning the approval of the proposed COSG Agreement?

A. For all these reasons discussed above, as well as the detailed discussion of the specific ratepayer risks discussed earlier in my testimony, I urge the Commission to deny the Application for the proposed COSG Agreement.

Q. Does this conclude your testimony?

A. Yes, it does.

<u>VERIFICATION</u>

STATE OF CONNECTICUT)

COUNTY OF FAIRFIELD) ss:

Andrea C. Crane, being duly sworn upon her oath, deposes and states that she is a consultant for the Citizens' Utility Ratepayer Board, that she has read and is familiar with the foregoing Direct Testimony, and that the statements made herein are true to the best of her knowledge, information and belief.

Andrea C. Crane

Andrea C. Crane

Subscribed and sworn before me this 16 day of March, 2016.

Notary Public Benjamin D Cotton

BENJAMIN D COTTON
Notary Public-Connecticut
My Commission Expires
June 30, 2017

My Commission Expires: ______________________

APPENDIX A

List of Prior Testimonies

The Columbia Group, Inc., Testimonies of Andrea C. Crane

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Black Hills/Kansas Gas Utility Company	G	Kansas	16-BHCG-171-TAR	3/16	Long-Term Hedge Contract	Citizens' Utility Ratepayer Board
General Investigation Regarding Accelerated Pipeline Replacement	G	Kansas	15-GIMG-343-GIG	1/16	Cost Recovery Issues	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	15-00261-UT	1/16	Revenue Requirements	Office of Attorney General
Atmos Energy Company	G	Kansas	16-ATMG-079-RTS	12/15	Revenue Requirements	Citizens' Utility Ratepayer Board
El Paso Electric Company	E	New Mexico	15-00109-UT	12/15	Sale of Generating Facility	Office of Attorney General
El Paso Electric Company	E	New Mexico	15-00127-UT	9/15	Revenue Requirements	Office of Attorney General
Rockland Electric Company	E	New Jersey	ER14030250	9/15	Storm Hardening Surcharge	Division of Rate Counsel
El Paso Electric Company	E	New Mexico	15-00099-UT	8/15	Certificate of Public Convenience - Ft. Bliss	Office of Attorney General
Southwestern Public Service Company	E	New Mexico	15-00083-UT	7/15	Approval of Purchased Power Agreements	Office of Attorney General
Westar Energy, Inc.	E	Kansas	15-WSEE-115-RTS	7/15	Revenue Requirements	Citizens' Utility Ratepayer Board
Kansas City Power and Light Company	E	Kansas	15-KCPE-116-RTS	5/15	Revenue Requirements	Citizens' Utility Ratepayer Board
Comcast Cable Communications	C	New Jersey	CR14101099-1120	4/15	Cable Rates (Form 1240)	Division of Rate Counsel
Liberty Utilities (Pine Buff Water)	W	Arkansas	14-020-U	1/15	Revenue Requirements	Office of Attorney General
Public Service Electric and Gas Co.	E/G	New Jersey	EO14080897	11/14	Energy Efficiency Program Extension II	Division of Rate Counsel
Black Hills/Kansas Gas Utility Company	G	Kansas	14-BHCG-502-RTS	9/14	Revenue Requirements	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	14-00158-UT	9/14	Renewable Energy Rider	Office of Attorney General
Public Service Company of New Mexico	E	New Mexico	13-00390-UT	8/14	Abandonment of San Juan Units 2 and 3	Office of Attorney General
Atmos Energy Company	G	Kansas	14-ATMG-320-RTS	5/14	Revenue Requirements	Citizens' Utility Ratepayer Board
Rockland Electric Company	E	New Jersey	ER13111135	5/14	Revenue Requirements	Division of Rate Counsel
Kansas City Power and Light Company	E	Kansas	14-KCPE-272-RTS	4/14	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Comcast Cable Communications	C	New Jersey	CR13100885-906	3/14	Cable Rates	Division of Rate Counsel
New Mexico Gas Company	G	New Mexico	13-00231-UT	2/14	Merger Policy	Office of Attorney General
Water Service Corporation (Kentucky)	W	Kentucky	2013-00237	2/14	Revenue Requirements	Office of Attorney General
Oneok, Inc. and Kansas Gas Service	G	Kansas	14-KGSG-100-MIS	12/13	Plan of Reorganization	Citizens' Utility Ratepayer Board
Public Service Electric & Gas Company	E/G	New Jersey	EO13020155 GO13020156	10/13	Energy Strong Program	Division of Rate Counsel
Southwestern Public Service Company	E	New Mexico	12-00350-UT	8/13	Cost of Capital, RPS Rider, Gain on Sale, Allocations	New Mexico Office of Attorney General

The Columbia Group, Inc., Testimonies of Andrea C. Crane

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Westar Energy, Inc.	E	Kansas	13-WSEE-629-RTS	8/13	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	13-115	8/13	Revenue Requirements	Division of the Public Advocate
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	13-MKEE-447-MIS	8/13	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Jersey Central Power & Light Company	E	New Jersey	ER12111052	6/13	Reliability Cost Recovery Consolidated Income Taxes	Division of Rate Counsel
Mid-Kansas Electric Company	E	Kansas	13-MKEE-447-MIS	5/13	Transfer of Certificate Regulatory Policy	Citizens' Utility Ratepayer Board
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	13-MKEE-452-MIS	5/13	Formula Rates	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	12-450F	3/13	Gas Sales Rates	Attorney General
Public Service Electric and Gas Co.	E	New Jersey	EO12080721	1/13	Solar 4 All - Extension Program	Division of Rate Counsel
Public Service Electric and Gas Co.	E	New Jersey	EO12080726	1/13	Solar Loan III Program	Division of Rate Counsel
Lane Scott Electric Cooperative	E	Kansas	12-MKEE-410-RTS	11/12	Acquisition Premium, Policy Issues	Citizens' Utility Ratepayer Board
Kansas Gas Service	G	Kansas	12-KGSG-835-RTS	9/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Kansas City Power and Light Company	E	Kansas	12-KCPE-764-RTS	8/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Woonsocket Water Division	W	Rhode Island	4320	7/12	Revenue Requirements	Division of Public Utilities and Carriers
Atmos Energy Company	G	Kansas	12-ATMG-564-RTS	6/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	110258	5/12	Cost of Capital	Division of the Public Advocate
Mid-Kansas Electric Company (Western)	E	Kansas	12-MKEE-491-RTS	5/12	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Atlantic City Electric Company	E	New Jersey	ER11080469	4/12	Revenue Requirements	Division of Rate Counsel
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	12-MKEE-380-RTS	4/12	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	G	Delaware	11-381F	2/12	Gas Cost Rates	Division of the Public Advocate
Atlantic City Electric Company	E	New Jersey	EO11110650	2/12	Infrastructure Investment Program (IIP-2)	Division of Rate Counsel
Chesapeake Utilities Corporation	G	Delaware	11-384F	2/12	Gas Service Rates	Division of the Public Advocate
New Jersey American Water Co.	W/WW	New Jersey	WR11070460	1/12	Consolidated Income Taxes Cash Working Capital	Division of Rate Counsel
Westar Energy, Inc.	E	Kansas	12-WSEE-112-RTS	1/12	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Puget Sound Energy, Inc.	E/G	Washington	UE-111048 UG-111049	12/11	Conservation Incentive Program and Others	Public Counsel

The Columbia Group, Inc., Testimonies of Andrea C. Crane

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Puget Sound Energy, Inc.	G	Washington	UG-110723	10/11	Pipeline Replacement Tracker	Public Counsel
Empire District Electric Company	E	Kansas	11-EPDE-856-RTS	10/11	Revenue Requirements	Citizens' Utility Ratepayer Board
Comcast Cable	C	New Jersey	CR11030116-117	9/11	Forms 1240 and 1205	Division of Rate Counsel
Artesian Water Company	W	Delaware	11-207	9/11	Revenue Requirements Cost of Capital	Division of the Public Advocate
Kansas City Power & Light Company	E	Kansas	10-KCPE-415-RTS (Remand)	7/11	Rate Case Costs	Citizens' Utility Ratepayer Board
Midwest Energy, Inc.	G	Kansas	11-MDWE-609-RTS	7/11	Revenue Requirements	Citizens' Utility Ratepayer Board
Kansas City Power & Light Company	E	Kansas	11-KCPE-581-PRE	6/11	Pre-Determination of Ratemaking Principles	Citizens' Utility Ratepayer Board
United Water Delaware, Inc.	W	Delaware	10-421	5/11	Revenue Requirements Cost of Capital	Division of the Public Advocate
Mid-Kansas Electric Company	E	Kansas	11-MKEE-439-RTS	4/11	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
South Jersey Gas Company	G	New Jersey	GR10060378-79	3/11	BGSS / CIP	Division of Rate Counsel
Chesapeake Utilities Corporation	G	Delaware	10-296F	3/11	Gas Service Rates	Division of the Public Advocate
Westar Energy, Inc.	E	Kansas	11-WSEE-377-PRE	2/11	Pre-Determination of Wind Investment	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	G	Delaware	10-295F	2/11	Gas Cost Rates	Attorney General
Delmarva Power and Light Company	G	Delaware	10-237	10/10	Revenue Requirements Cost of Capital	Division of the Public Advocate
Pawtucket Water Supply Board	W	Rhode Island	4171	7/10	Revenue Requirements	Division of Public Utilities and Carriers
New Jersey Natural Gas Company	G	New Jersey	GR10030225	7/10	RGGI Programs and Cost Recovery	Division of Rate Counsel
Kansas City Power & Light Company	E	Kansas	10-KCPE-415-RTS	6/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Atmos Energy Corp.	G	Kansas	10-ATMG-495-RTS	6/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Empire District Electric Company	E	Kansas	10-EPDE-314-RTS	3/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	09-414 and 09-276T	2/10	Cost of Capital Rate Design Policy Issues	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	09-385F	2/10	Gas Cost Rates	Division of the Public Advocate
Chesapeake Utilities Corporation	G	Delaware	09-398F	1/10	Gas Service Rates	Division of the Public Advocate
Public Service Electric and Gas Company	E	New Jersey	ER09020113	11/09	Societal Benefit Charge Non-Utility Generation Charge	Division of Rate Counsel

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Delmarva Power and Light Company	G	Delaware	09-277T	11/09	Rate Design	Division of the Public Advocate
Public Service Electric and Gas Company	E/G	New Jersey	GR09050422	11/09	Revenue Requirements	Division of Rate Counsel
Mid-Kansas Electric Company	E	Kansas	09-MKEE-969-RTS	10/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Westar Energy, Inc.	E	Kansas	09-WSEE-925-RTS	9/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Jersey Central Power and Light Co.	E	New Jersey	EO08050326 EO08080542	8/09	Demand Response Programs	Division of Rate Counsel
Public Service Electric and Gas Company	E	New Jersey	EO09030249	7/09	Solar Loan II Program	Division of Rate Counsel
Midwest Energy, Inc.	E	Kansas	09-MDWE-792-RTS	7/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Westar Energy and KG&E	E	Kansas	09-WSEE-641-GIE	6/09	Rate Consolidation	Citizens' Utility Ratepayer Board
United Water Delaware, Inc.	W	Delaware	09-60	6/09	Cost of Capital	Division of the Public Advocate
Rockland Electric Company	E	New Jersey	GO09020097	6/09	SREC-Based Financing Program	Division of Rate Counsel
Tidewater Utilities, Inc.	W	Delaware	09-29	6/09	Revenue Requirements Cost of Capital	Division of the Public Advocate
Chesapeake Utilities Corporation	G	Delaware	08-269F	3/09	Gas Service Rates	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	08-266F	2/09	Gas Cost Rates	Division of the Public Advocate
Kansas City Power & Light Company	E	Kansas	09-KCPE-246-RTS	2/09	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Jersey Central Power and Light Co.	E	New Jersey	EO08090840	1/09	Solar Financing Program	Division of Rate Counsel
Atlantic City Electric Company	E	New Jersey	EO06100744 EO08100875	1/09	Solar Financing Program	Division of Rate Counsel
West Virginia-American Water Company	W	West Virginia	08-0900-W-42T	11/08	Revenue Requirements	The Consumer Advocate Division of the PSC
Westar Energy, Inc.	E	Kansas	08-WSEE-1041-RTS	9/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Artesian Water Company	W	Delaware	08-96	9/08	Cost of Capital, Revenue, New Headquarters	Division of the Public Advocate
Comcast Cable	C	New Jersey	CR08020113	9/08	Form 1205 Equipment & Installation Rates	Division of Rate Counsel
Pawtucket Water Supply Board	W	Rhode Island	3945	7/08	Revenue Requirements	Division of Public Utilities and Carriers
New Jersey American Water Co.	W/WW	New Jersey	WR08010020	7/08	Consolidated Income Taxes	Division of Rate Counsel
New Jersey Natural Gas Company	G	New Jersey	GR07110889	5/08	Revenue Requirements	Division of Rate Counsel
Kansas Electric Power Cooperative, Inc.	E	Kansas	08-KEPE-597-RTS	5/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board

The Columbia Group, Inc., Testimonies of Andrea C. Crane

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Public Service Electric and Gas Company	E	New Jersey	EX02060363 EA02060366	5/08	Deferred Balances Audit	Division of Rate Counsel
Cablevision Systems Corporation	C	New Jersey	CR07110894, et al..	5/08	Forms 1240 and 1205	Division of Rate Counsel
Midwest Energy, Inc.	E	Kansas	08-MDWE-594-RTS	5/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	07-246F	4/08	Gas Service Rates	Division of the Public Advocate
Comcast Cable	C	New Jersey	CR07100717-946	3/08	Form 1240	Division of Rate Counsel
Generic Commission Investigation	G	New Mexico	07-00340-UT	3/08	Weather Normalization	New Mexico Office of Attorney General
Southwestern Public Service Company	E	New Mexico	07-00319-UT	3/08	Revenue Requirements Cost of Capital	New Mexico Office of Attorney General
Delmarva Power and Light Company	G	Delaware	07-239F	2/08	Gas Cost Rates	Division of the Public Advocate
Atmos Energy Corp.	G	Kansas	08-ATMG-280-RTS	1/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board

APPENDIX B

Referenced Data Requests

CURB-1

CURB-45

CURB-50

CURB-67

CURB-77

CURB-106

APPLICATION TO APPROVE TARIFF REVISIONS RELATED
TO ITS COST OF SERVICE GAS AGREEMENT

REQUEST DATE: November 12, 2015

RESPONSE DATE: November 30, 2015

REQUESTING PARTY: CITIZENS' UTILITY RATEPAYER BOARD (CURB)

CURB Data Request No. 1-1: Is the Company aware of any state regulatory commission that has approved a program identical to the one being proposed in this case, whereby an unregulated affiliate would purchase an interest in gas reserves and flow through profits or losses around a benchmark level of return to ratepayers? If so, please identify each such regulatory jurisdiction and provide a citation for each such approval.

Response to CURB Data Request No. 1-1: The Company is unaware of any state regulatory commission that has approved a program identical to that proposed. Utah and Wyoming have approved a Questar Gas program, under which its unregulated affiliate Wexpro purchases gas reserves and provides a specified return to shareholders under the Wexpro II agreement. However, under that program, physical gas flows through to customers. Oregon has approved the investment in gas reserves for Northwest Natural Gas (NWN) and the interest is held in a utility subsidiary. In the NWN program, gas produced is sold into the market and proceeds net of NWN's revenue requirement are credited to customers. The rate of return to shareholders is set at NWN's utility allowed rate of return. NWN does have the ability to deliver physical gas to customers, but to the Company's knowledge has chosen not to so as to maximize the tax and other benefits to customers. For clarification, the Company is flowing through hedge credits and hedge costs tied to a revenue requirement calculation rather than flowing through the profits and losses of its affiliate. The COSG Program is similar to the other utility programs mentioned above in that they seek to provide long-term price stability and earn a return on invested capital. The COSG Program chose to house the gas reserves in an affiliate to maximize tax attributes for the benefit of the Company's customers.

Response provided by: Ivan Vancas

Attachments: None

BLACK HILLS ENERGY
KS KCC DOCKET NO. 16-BHCG-171-TAR

APPLICATION TO APPROVE TARIFF REVISIONS RELATED
TO ITS COST OF SERVICE GAS AGREEMENT

REQUEST DATE: January 11, 2016

RESPONSE DATE: January 25, 2016

REQUESTING PARTY: CITIZENS' UTILITY RATEPAYER BOARD (CURB)

CURB Data Request No. 45: On page 17 of the transcript of the BKH 2015 Analyst Day October 8, 2015 presentation it is indicated that the net book value of gas resources would not be used in the calculation of the value of the gas resources, but rather an engineering evaluation on a present value basis would be used. Please reconcile that with the response to CURB 1-6 which indicates that the book value of equity used to acquire and develop reserves resources would be used to calculate the "actual ROE." Is the intention to purchase the reserves (or a portion of the reserves) from Piceance at a price greater than the book value of the Piceance assets, establish a separate rate base amount for that purchase, and then use that as the basis for calculating return? Please explain your answer.

Response to CURB Data Request No. 45: The Company has not proposed any specific property for inclusion in the COSG Program and will not be in a position to do so until it knows the approved structure of the COSG Program. Any acquisition from an affiliate will have to meet Part 3 of the Acquisition Criteria listed in Exhibit A of the COSG Agreement. This additional requirement, for any transaction between affiliates, requires a review by an independent third-party that opines that the transfer price is fair based on other deals with unrelated third-parties that are known in the market. As is common industry practice for valuing reserve interests, the transfer price will be developed based upon a petroleum engineer developing a reserve report for the property and determining the net-present-value of the cash flows created as the reserves are produced. This present value (and transfer value) then becomes the book value and beginning Investment Base for COSGCO.

If the Piceance is the proposed property, the intention would be to transfer it at market value, in the ordinary course of business. The selling affiliate could have a profit or loss based upon the transfer price to COSGCO when compared to its own book value.

Response provided by: **Aaron Carr / Chris Kilpatrick**

Attachments: None.

APPLICATION TO APPROVE TARIFF REVISIONS RELATED
TO ITS COST OF SERVICE GAS AGREEMENT

REQUEST DATE: January 11, 2016

RESPONSE DATE: January 25, 2016

REQUESTING PARTY: CITIZENS' UTILITY RATEPAYER BOARD (CURB)

CURB Data Request No. 50: Would the Company be willing to transfer its Piceance assets to COSGCO for book value, given that the filing proposes a utility rate structure and rate of return? If not, explain why not.

Response to CURB Data Request No. 50: No, the Company would not transfer its Piceance assets to COSGCO for book value. Any acquisition from an affiliate will have to meet Part 3 of the Acquisition Criteria listed in Exhibit A of the COSG Agreement. This additional requirement, for any transaction between affiliates, requires a review by an independent third-party that opines that the transfer price is fair based on other deals with unrelated third-parties that are known in the market. The transfer price will be developed based upon a petroleum engineer developing a reserve report for the property and determining the net present value of the cash flows created as the reserves are produced.

Response provided by: **Ivan Vancas**

Attachments: None.

APPLICATION TO APPROVE TARIFF REVISIONS RELATED TO ITS COST OF SERVICE GAS AGREEMENT

REQUEST DATE: January 11, 2016

RESPONSE DATE: January 25, 2016

REQUESTING PARTY: CITIZENS' UTILITY RATEPAYER BOARD (CURB)

CURB Data Request No. 67: Would COSGCO continue to produce gas if the price of natural gas fell below production costs? Explain how ratepayers would be protected in this scenario, and what ongoing costs they would still be responsible for.

Response to CURB Data Request No. 67: Yes, COSGCO would continue to produce gas from existing wells. If gas prices remain low for an extended period, COSGCO would seek to adjust its Drilling Plan accordingly. Furthermore, the Drilling Plan Criterion provides customer protections in the situation described in the request. As the COSG Program is only proposed for 50% of the Company's annual firm demand, customers would still realize the lower spot market natural gas prices for that portion of the gas portfolio.

Response provided by: **Aaron Carr**

Attachments: None.

BLACK HILLS ENERGY
KS KCC DOCKET NO. 16-BHCG-171-TAR

APPLICATION TO APPROVE TARIFF REVISIONS RELATED
TO ITS COST OF SERVICE GAS AGREEMENT

REQUEST DATE: January 11, 2016

RESPONSE DATE: January 25, 2016

REQUESTING PARTY: CITIZENS' UTILITY RATEPAYER BOARD (CURB)

CURB Data Request No. 77: If it should be determined by relevant authorities that earthquakes can be attributed to drilling activities, and this results in expenses for alternative drilling techniques or technologies, or even the abandonment of the assets, are the utility companies responsible for all the costs of such an outcome, including capping wells and remediating the properties, paying fines, compensating BHUH for the value of the abandoned assets, etc?

Response to CURB Data Request No. 77: If the regulation of the development and operation of COSGCO's properties changes, any associated costs COSGCO incurs will be included in the calculation of Hedge Credits and Hedge Costs.

Response provided by: **Legal / Aaron Carr / John Benton**

Attachments: None.

BLACK HILLS ENERGY
KS KCC DOCKET NO. 16-BHCG-171-TAR

APPLICATION TO APPROVE TARIFF REVISIONS RELATED
TO ITS COST OF SERVICE GAS AGREEMENT

REQUEST DATE: February 1, 2016

RESPONSE DATE: February 15, 2016

REQUESTING PARTY: CITIZENS' UTILITY RATEPAYER BOARD (CURB)

CURB Data Request No. 106: Please provide for the Kansas jurisdiction the percentage of gas supplies that were hedged in each of the last five years, by instrument, and a projection of the amount of gas to be hedged for Kansas in each of the first ten years of the proposed COGSCO proposal, by instrument (including storage).

Response to CURB Data Request No. 106:

In Kansas, as explained in response to CURB Data Request No. 107, a statewide approach utilizing options has been in place for a number of years. The purchase of options in Kansas is not based on a percent of the portfolio, but rather a targeted dollar amount per customer per year. This approach was implemented following customer surveys. In addition to options, BHUH makes use of available contract storage service on Kansas pipelines, which approximated 10-15% of annual demand in the past five years.

As indicated in the direct testimony of Mr. Loomis, it is the Company's recommendation that 50% of the gas supply portfolio consist of a long-term physical hedge through the COSG Program. The balance of the Company's gas supply portfolio will layer in short-term and medium term financial hedges, seasonal storage, and spot market purchases, as appropriate. The percentage of gas to be hedged by instrument will be determined subsequent to approval of the COSG Program and approval of a property acquisition with the accompanying five-year drilling plan.

Response provided by: **Chuck Loomis**

Attachments: None.

CERTIFICATE OF SERVICE

16-BHCG-171-TAR

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing document was served by electronic service on this 21st day of March, 2016, to the following:

JAMES G. FLAHERTY, ATTORNEY
ANDERSON & BYRD, L.L.P.
216 S HICKORY
PO BOX 17
OTTAWA, KS 66067
jflaherty@andersonbyrd.com

PATRICK JOYCE, SR MANAGING COUNSEL
BLACK HILLS/KANSAS GAS UTILITY COMPANY, LLC D/B/A BLACK HILLS ENERGY
1102 EAST 1ST ST
PAPILLION, NE 68046
patrick.joyce@blackhillscorp.com

DARCY FABRIZIUS
CONSTELLATION NEWENERGY-GAS DIVISON, LLC
N21 W23340 RIDGEVIEW PARKWAY
WAUKESHA, WI 53188
darcy.fabrizius@constellation.com

LYNDA FOHN
CONSTELLATION NEWENERGY-GAS DIVISON, LLC
1221 LAMAR, STE 850
HOUSTON, TX 77010
lynda.fohn@constellation.com

ROBERT J. ALESSI
DLA Piper LLP
1251 AVENUE OF AMERICAS
NEW YORK, NY 10020-1104
robert.alessi@dlapiper.com

JOHNATHAN NATHAN C. FISH
DLA Piper LLP
1717 MAIN STREET
SUITE 4600
DALLAS, TX 75201-4629
nathan.fish@dlapiper.com

JUAN J. GODINEZ
DLA Piper LLP
2525 E CAMELBACK ROAD, STE 1000
PHOENIX, AZ 85016
juan.godinez@dlapiper.com

MARK NADEAU, ATTORNEY
DLA Piper LLP
2525 E CAMELBACK ROAD, STE 1000
PHOENIX, AZ 85016
mark.nadeau@dlapiper.com

SAMUEL FEATHER, OFFICE OF GENERAL COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604-4027
s.feather@kcc.ks.gov

ANDREW FRENCH, SENIOR LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604-4027
a.french@kcc.ks.gov

MICHAEL NEELEY, LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604-4027
m.neeley@kcc.ks.gov

CAMERON L. SABIN, ATTORNEY
STOEL RIVES LLP
201 S MAIN ST
SUITE 1100
SALT LAKE CITY, UT 84111-4904
cameron.sabin@stoel.com

Della Smith
Administrative Specialist