BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A − ______G

IN THE MATTER OF THE VERIFIED APPLICATION OF BLACK HILLS COLORADO GAS, INC. FOR APPROVAL TO RECOVER GAS COSTS ASSOCIATED WITH THE FEBRUARY EXTREME COLD WEATHER EVENT

DIRECT TESTIMONY AND ATTACHMENTS OF

MICHAEL J. HARRINGTON

ON BEHALF OF

BLACK HILLS COLORADO GAS, INC.

NOTICE OF CONFIDENTIALITY

A portion of this document is filed under seal.

THE FOLLOWING ATTACHMENTS HAVE BEEN FILED UNDER SEAL:

Hearing Exhibit 101, Attachment MJH-1HC: February Event Costs
Hearing Exhibit 101, Attachment MJH-1C: February Event Costs
Hearing Exhibit 101, Attachment MJH-2C: Amortization & Bill Impacts
Hearing Exhibit 101, Attachment MJH-7HC: Existing GCA

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

May 18, 2021

SUMMARY OF THE DIRECT TESTIMONY OF MICHAEL J. HARRINGTON

Mr. Michael J. Harrington is Director of Regulatory & Finance. He serves as the policy witness, and he introduces the other Company witnesses testifying in this proceeding. He addresses the specific Commission approvals the Company is requesting for the recovery of the extraordinary natural gas commodity costs incurred as a result of the extreme weather and natural gas event that took place across the country in February 2021, and in particular from February 13-17, 2021 (the "February Event"). Mr. Harrington addresses that the February Event involved a confluence of factors including an arctic cold across the nation, record high customer demand, and the freeze off of natural gas production and processing facilities that resulted in an unprecedented spike in the price of natural gas that is delivered through interstate pipelines and purchased based on market index prices.

Despite these various challenges, he explains the Company worked diligently to prudently procure gas supplies and ensure the continued safety and reliability of gas services that its customers' health and wellbeing depends upon. The Company did not have major outages to its customers. The February Event involved a price spike that was not foreseeable, nor within the Company's control. The Company thus incurred extraordinary natural gas costs in purchasing necessary supplies to keep its gas flowing and customers warm. The Company was able to mitigate the impacts of the price spike through proactive and diversified gas supply purchases, including the use of baseload, storage, daily spot purchases (including both ratable and non-ratable), and firm peaking contracts that saved customers approximately $67.8 million.

Mr. Harrington addresses the Commission's response to the February Event, and he provides Table MJH-1, which includes references to where in witness testimonies the Commission's specific requests for information can be located.

Mr. Harrington explains that it is appropriate to consider the February Event as occurring from February 13 through February 17. The market price for natural gas during these days was extraordinary, eclipsing by a wide margin elevated natural gas prices experienced during the 2014 Polar Vortex event. From February 13-17, Mr. Harrington explains the Company incurred a total cost of natural gas of $75,692,864. Of this amount, and based on several repricing scenarios, Mr. Harrington provides that the incremental and extraordinary costs related to the February Event total $72,666,626.

Mr. Harrington provides seven different scenarios for the treatment of the extraordinary costs, including with associated bill impacts. Of these scenarios, the Company proposes different treatment for its Gas Cost Adjustment ("GCA") regions. For the Central and North/Southwest GCA regions, the Company proposes a three-year amortization period with a carrying cost tied to the Company's short and long-term cost of debt. For the Western Slope GCA region, the Company proposes a one-year amortization period with a carrying cost that is based on the Company's short-term cost of debt. These carrying costs for the different GCA regions match the length of their amortization periods.

Mr. Harrington proposes recovery of the extraordinary costs from the February Event through a new rate mechanism in the tariffs titled "Extraordinary Cost Recovery Rider" and as a new line item on customer bills called the "ECRR." This new rate mechanism will ensure that the extraordinary costs are not recovered through the Company's existing GCA. The Extraordinary Cost Recovery Rider has a rate design that mirrors the GCA. The Company proposes to begin cost recovery through the Extraordinary Cost Recovery Rider beginning on November 1, 2021.

Mr. Harrington addresses the Company's proactive communications with customers during the February Event to inform them of the need and importance of taking action to conserve their energy needs. He explains the Company used the following communication channels to reach customers: (1) the customer call center; (2) energy efficiency content; (3) media and press statements (which resulted in coverage in local media); (4) customer emails; (5) Company website materials; and (6) comprehensive use of social media platforms, including Facebook, LinkedIn, Instagram, and Twitter. Mr. Harrington's attachments explain the communications it provided to customers.

He also provides a high-level overview of the Company's management review process and how it was implemented during the February Event. These processes resulted in the release of communication efforts, compliance with internal company policies on a timely basis, the obtaining of credit assurances to obtain gas supplies, and the obtaining of short-term debt to fund the extraordinary costs of the February Event.

In an effort to aid the Commission, Mr. Harrington briefly explains relevant Commission precedent on the review of GCA and Energy Cost Adjustment expenditures.

Finally, he concludes by addressing the Company's request for waivers and variances (as necessary) to ensure the Company can comply with the Commission's directive to separately record, track, and recover the extraordinary costs of the February Event.

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Hearing Exhibit 101, Attachment MJH-7: Existing GCA

List of Acronyms

ALJ	Administrative Law Judge
Bcf/d	billion cubic feet per day
BHC	Black Hills Corporation
BHCG	Black Hills Colorado Gas, Inc.
BHSC	Black Hills Service Company, LLC
Company	Black Hills Colorado Gas, Inc.
CSU	Colorado Springs Utilities
ECA	Electric Cost Adjustment
EIA	Energy Information Administration
ECRR	Extraordinary Cost Recovery Rider
February Event	February 13-17, 2021
FERC	Federal Energy Regulatory Commission
GCA	Gas Cost Adjustment
GPP	Gas Purchase Plan
GPR	Gas Purchase Report
LIBOR	London Inter-Bank Offered Rate
PSCo	Public Service Company of Colorado

DIRECT TESTIMONY OF MICHAEL J. HARRINGTON

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael J. Harrington. My business address is 1515 Arapahoe Street, Tower 1 - Suite 1200, Denver, Colorado 80202.

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

A. I am employed by Black Hills Service Company, LLC ("BHSC"), a wholly owned subsidiary of Black Hills Corporation ("BHC"). I am a Director of Regulatory & Finance.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Black Hills Colorado Gas, Inc. ("BHCG" or the "Company") d/b/a Black Hills Energy.

II. STATEMENT OF QUALIFICATIONS

Q. WHAT ARE THE DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I am responsible for managing all aspects of the regulatory and financial process for Black Hills, both electric and gas. I manage the development of regulatory filings and initiatives that support business strategies and regulatory policies. In addition, I manage the development, analysis, and interpretation of financial forecasts, including budgets and strategic plans for Black Hills. I manage a department of eleven professionals in regulatory and financial planning and analysis functions.

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. My education, employment history and professional experience is provided in Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Direct Testimony is to support BHCG's request to recover the extraordinary natural gas commodity costs incurred as a result of the extreme weather and natural gas event that took place across the country in February 2021, and in particular from February 13-17, 2021 (the "February Event"). I introduce the other Company witnesses who support this application as well. I provide an overview of how arctic cold gripped the nation and caused an unprecedented spike in the market price of natural gas. I explain how the Company responded to ensure service was not interrupted during the extreme event. I discuss the prudent steps the Company made to mitigate cost and to inform and encourage customers of their ability to conserve energy during the February Event. I provide a brief overview of the Company's Commission-approved hedging plan and how that hedging plan does not address intra-monthly price spikes. I provide an overview of the management review process during the February Event, and I explain the standards for Commission review of these costs.

Q. WHO ARE THE COMPANY'S OTHER WITNESSES PROVIDING SUPPORTING TESTIMONY IN THIS PROCEEDING?

A. The following witness provides testimony in support of this filing:

Mr. Jay D. Bauer, Senior Manager, Gas Supply Services. Mr. Bauer generally describes the natural gas system and natural gas purchasing, he explains the typical process to contract for natural gas, he discusses the Company's gas purchasing practices, and he addresses the natural gas purchases that took place during the February Event. Mr. Bauer provides background information on the Company's Gas Purchase Plans that are filed annually with the Commission and he explains that the prudent gas purchasing decisions made by the Company saved customers $67.8 million over the February Event.

Q. WHAT ARE THE ATTACHMENTS TO YOUR TESTIMONY?

A. Following is the list of attachments to my testimony:

Hearing Exhibit 101, Attachment MJH-1HC: February Event Cost

Hearing Exhibit 101, Attachment MJH-1C: February Event Cost

Hearing Exhibit 101, Attachment MJH-1: February Event Cost

Hearing Exhibit 101, Attachment MJH-2C: Amortization & Bill Impacts

Hearing Exhibit 101, Attachment MJH-2: Amortization & Bill Impacts

Hearing Exabit 101, Attachment MJH-3: *Pro Forma* Tariffs

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Hearing Exhibit 101, Attachment MJH-6: Customer Communication Examples

Hearing Exhibit 101, Attachment MJH-7HC: Existing GCA

Hearing Exhibit 101, Attachment MJH-7: Existing GCA

Q. WHAT ARE THE COMPANY'S REQUESTS FOR COMMISSION APPROVAL IN THIS PROCEEDING?

A. The Company is specifically requesting the Commission to:

- Approve the February Event extraordinary cost amount;
- Approve the proposed three-year amortization period of the February Event regulatory asset for the Central and North/Southwest GCA Regions and a one-year amortization period of a regulatory asset from the Western Slope GCA region;
- Approve carrying costs on the February Event regulatory assets for the Central and North/Southwest GCA regions based on the Company's short and long-term costs of debt, and for the Western Slope GCA region based on the Company's short-term cost of debt;
- Approve the new line "Extraordinary Cost Recovery Rider" that will be shown on customer bills as the "ECRR;"
- Approve the proposed effective date of the new line item surcharge of November 1, 2021;
- Approve the revisions to the GCA Tariff provided in Attachment MJH-3 (redlined); and
- Approve waivers and variances as appropriate for the GCA tariff and GCA rules as necessary.

IV. BACKGROUND

Q. PLEASE PROVIDE AN OVERVIEW OF THE FEBRUARY EVENT.

A. In February 2021, an arctic cold gripped the nation and caused an historic natural gas event.[1] During this event, natural gas wells and production and processing facilities in certain parts of the nation froze off, resulting in a major portion of the nation's gas supply going offline.[2] The Energy Information Administration ("EIA") reported that U.S. dry natural gas production fell to as low as 69.7 billion cubic feet per day ("Bcf/d") on February 17, a decline of 21%, or down nearly 18.9 Bcf/d from the week ending February 13. Also, according to EIA, natural gas production in Texas fell almost 45% from 21.3 Bcf/d during the week ending February 13 to a daily low of 11.8 Bcf/d on Wednesday, February 17. EIA further reported that the decline in natural gas production was mostly a result of freeze-offs, which occur when water and other liquids in the raw natural gas stream freeze at the wellhead or in natural gas gathering lines near processing facilities.[3]

The loss of natural gas production occurred while record-breaking cold temperatures engulfed much of the country, including in the Company's service territory. At one point, every Black Hills Energy customer – from western Wyoming to northeastern Arkansas – simultaneously endured below zero temperatures. The cold weather led to increased natural gas demand. BHCG experienced a new system peak demand day on February 14.

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[1] MISO, Overview of February 2021 Arctic Weather, at Slide 4 (showing significant average temperate deviations from normal weather from February 12-18, 2021 across the midcontinent), available at: https://cdn.misoenergy.org/20210311%20MSC%20Item%2004%20Max%20Gen%20Feb%2015530356.pdf

[2] U.S. Department of Energy, Extreme Cold & Winter Weather, Update #2, February 17, 2021, available at: https://www.energy.gov/sites/prod/files/2021/02/f82/TLP-WHITE_DOE%20Situation%20Update_Cold%20%20Winter%20Weather_%20Report%20%232%20FIN.pdf

[3] EIA website article: Texas natural gas production fell by almost half during recent cold snap - Today in Energy - U.S. Energy Information Administration (EIA), available at: https://www.eia.gov/todayinenergy/detail.php?id=46896

The extreme weather and natural gas event forced utility outages across the country, preventing some utilities from serving customers necessary and life-sustaining energy. While much of the focus has been on the State of Texas, this event had a significant impact across nearly half of the country. For example, two of the nation's largest regional transmission organizations/independent system operators—the Midcontinent Independent System Operator and the Southwest Power Pool—experienced curtailments and blackouts impacting millions of citizens.[4]

Q. DID THE FEBRUARY EVENT IMPACT NATURAL GAS PRICES?

A. Yes. The February Event involved an interplay of abnormally cold weather, freeze-offs of natural gas production, and high customer demand for natural gas. This combination of factors greatly impacted the price to purchase natural gas delivered through interstate pipelines that is set based on applicable market index prices. Several natural gas trading hubs experienced record highs during the February Event. At the Henry Hub prices on February 17 reached $23.86 per million British thermal units, which is the highest real price at this hub since 2003.[5] The spot gas index for February as compared to January was up by 899.7% at $25.135/MMBtu at Midcontinent, by 416.5% at $13.586/MMBtu in the West, and by 249.0% at $9.007/MMBtu on the Gulf Coast.[6]

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[4] Winter weather causes forced outages in parts of MISO's South Region, available at: https://www misoenergy.org/about/media-center/miso-load-demand-reaches-an-all-time-high-in-western-south-region/; SPP implements rolling blackouts to cope with high power demand from winter blast, available at: https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/021521-spp-implements-rolling-blackouts-to-cope-with-high-power-demand-from-winter-blast

[5] Cold weather brings near record-high natural gas spot prices, EIA, available at: https://www.eia.gov/todayinenergy/detail.php?id=47016

[6] S&P Global Market Intelligence, February spot gas values in parts of US grew by 900% month over month, available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/february-spot-gas-values-in-parts-of-us-grew-by-900-month-over-month-62948924

Q. DID THE EVENT IMPACT COLORADO?

A. Unfortunately, the February Event impacted the natural gas market in Colorado, causing sudden and very large increases to natural gas prices. The impact to natural gas prices was experienced at the Colorado interstate pipelines, and therefore, to utilities that buy gas from these pipelines. Company witness Mr. Bauer addresses the increase in Colorado gas prices.

The impact to Colorado utilities was not limited to only investor-owned utilities, but to the municipal and joint power utilities that have natural gas generation as part of their baseload supply. For instance, the Colorado Springs Utilities ("CSU") experienced $105.3 million in additional fuel costs.[7] This municipal utility has imposed a rate increase that results in a roughly $22 monthly bill increase for their average, natural gas residential customers, which is a nearly 60 percent increase.[8] The impact to CSU was experienced similarly by other utilities elsewhere in Colorado. The impacts were not related to the business model of the utility (*i.e.*, investor-owned utility or municipal utility), and the impacts were due to the overall natural gas market. During the February Event, market prices for natural gas rose dramatically.

Q. DO YOU CONSIDER THE FEBRUARY EVENT AS A MARKET EVENT?

A. Yes. During the February Event extreme artic cold weather gripped Colorado; however, Colorado is accustomed to cold weather. The utilities throughout Colorado did not experience widespread outages or other detrimental weather-based issues with their infrastructure. Black Hills' system was able to "weather the storm," and it provided

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[7] Natural gas price hike approved for 14 months in Colorado Springs after February weather, available at: https://www fox21news.com/news/local/cos-city-council-to-vote-on-natural-gas-price-increase-tuesday/
[8] Colorado Spring Utilities, Cost Adjustment, available at: https://www.csu.org/Pages/CostAdjustments.aspx

continuous service during the cold snap. Simply put, the extreme arctic cold weather did not impact Black Hills' ability to provide safe and reliable service.

Weather aside, the need for this application is due to the broader natural gas market. The extraordinary spike in market prices for natural gas caused utilities to pay high prices to serve customers. The price of gas is a market function and one in which the Company has no control. In this instance it was a significant market event that caused the Company to pay far more for natural gas than was typical. But for the extraordinary spike in the market price of natural gas, the Commission would likely have had no need to open an investigation docket, nor would there be a need for this instant proceeding.

Q. HOW DID BLACK HILLS GENERALLY RESPOND TO THE INCREASED DEMAND DUE TO THE COLD WEATHER?

A. As arctic cold gripped Colorado, Black Hills stood ready to respond to the significant increases in customer energy demand placed upon our system. Our team members continually monitored energy supply and adjusted as needed to ensure system integrity, while meeting extraordinary customer demand. Locally, technicians bundled up to physically inspect and monitor key infrastructure and were ready to respond. Black Hills' resilient utility fleets performed remarkably in meeting customer needs and demands. Black Hills also launched communication efforts to inform its customers of the event and actions they could take to conserve energy. Despite the tremendous challenges, Black Hills was able to avoid any outages or rolling blackouts through prudent decisions. Because we take our obligation to serve very seriously and view reliability as a priority, Black Hills worked tirelessly for its customers to ensure the lights stayed on and the gas was available.

Q. HOW DID THE COMMISSION RESPOND TO THE FEBRUARY MARKET EVENT?

A. On February 17, through Decision No. C21-0087, the Commission opened an investigatory proceeding, Proceeding No. 21I-0076EG, to receive information from the utilities regarding actions taken during the February Event. The utilities were directed to provide a situational report and to respond to several questions posed by the Commission.[9] On March 8, and through subsequent filings, Black Hills provided its preliminary situational report and responded to the Commission's questions. Much of the information the Company provided to the Commission in Proceeding No. 21I-0076EG is provided in this application as well, updated and revised as necessary.

On March 23, through Decision No. C21-0179, the Commission opened a miscellaneous proceeding, Proceeding No. 21M-0130EG, to examine certain guidelines and timelines for the Colorado utilities to make their individual cost recovery filings. I also discuss this decision further below.

Q. HAS THE COMMISSION DIRECTED THE FILING OF THIS APPLICATION?

A. Yes. On April 30, the Commission issued Decision No. C21-0261, directing Black Hills Colorado Gas, LLC to file an application to address the recovery of the extraordinarily high expenses incurred for its utility operations in response to the February Event.[10]

Decision No. C21-0261, at paragraphs 31-32, provided a list of information that the Commission stated should be provided in the utility cost recovery applications. The table

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[9] Proceeding No. 21I-0076EG, Decision No. C21-0101 at Ordering ¶ 4. The Commission subsequently requested additional information in the situational reports in Proceeding No. 21I-0076EG, in its Decision No. C21-0149, at ¶ 4.
[10] Proceeding No. 21M-0130EG, Decision No. C21-0261 at Ordering ¶ 3.

below provides that list of requested information along with an associated reference of where that information can be found in the Company's application.

Table MJH-1: Commission's Requested Information List

Description	Testimony Reference
A detailed timeline of events and when information was available to the utility, covering weather forecasts, load forecasts, gas hub pricing, actual gas purchases, gas supply offers received, actual gas usage, storage withdrawals, customer communication, curtailments, contract price settlement, etc.	HE 101 at Sections X-XI; HE 102 at Section VI, Attachments JDB-2, JDB-3, JDB-4, JDB-5, JDB-6
A detailed accounting of timing, volumes, and pricing of all gas supplies used to serve customer load over the period including long and short-term purchases, storage withdrawals, and pipeline balancing volumes and charges by rate area, as suggested by Staff.	HE 101 at Attachment MJH-1; HE 102 at Attachments JDB-2, JDB-3, JDB-4, JDB-5, JDB-6, JDB-7
A detailed accounting of gas storage including volumes in storage prior to the event, withdrawal limits, volumes used over the course of the event, etc., by rate area, as suggested by Staff.	HE 101 at Attachment MJH-1; HE 102 at Attachment JDB-7
A detailed accounting of actual gas demand by rate area and customer class, as suggested by Staff.	HE 102 at Section VI
All customer communications with details on the timing and distribution of the communications and estimated impact on customer behavior, as suggested by Staff.	HE 101 at Section X and Attachments MJH-5 and MJH-6
Information regarding baseline February gas forecasts for the implementation of the utility's GCA including: expected gas demand, volume, and pricing of purchases, storage volume and pricing, and any other costs included in the GCA, as suggested by Staff.	HE 102 at Attachment MJH-7
A detailed description of the management review process for the gas supply and demand decisions over the event period, including details regarding when and how decisions were made as to gas supplies (both purchased and in storage), what and when to communicate with customers, what other actions were discussed or taken to address the extraordinary event, etc., as suggested by Staff. Likewise, the application filing shall explain when the utility was aware of the extraordinary pricing, who within the utility approved the gas purchasing, as well as other actions taken or not taken.	HE 101 at Sections X-XI; HE 102 at Section VI
A detailed description of the utility's response to events in relation to their corporate parent, as suggested by the OCC and CEO.	HE 101 at Sections VIII, X-XI

Description	Testimony Reference
A detailed account of any defaults on gas deliveries during the event and the utility's recourse and stage of recompense, as suggested by the OCC and CEO.	HE 102 at Section VI
Costs incurred in response to the February 2021 extreme weather event amortized over 24 months with no carrying costs recovered from ratepayers.	HE 101 at Section VII and Attachment MJH-2
Costs incurred in response to the February 2021 extreme weather event amortized over 60 months with carrying costs recovered from ratepayers calculated at the utility's weighted average cost of long-term debt.	HE 101 at Section VII and Attachment MJH-2
Costs incurred in response to the February 2021 extreme weather event amortized over 84 months with carrying costs recovered from ratepayers calculated at the cost of senior secured bonds rated "AA" or "AA2" or better by at least one major independent credit rating agency[11] or some other reasonable measure of financing the amortization through securitization.	HE 101 at Section VII and Attachment MJH-2

V. SAFETY AND RELIABILITY

Q. PLEASE ADDRESS THE SAFETY AND RELIABILITY OF THE BLACK HILLS SYSTEM DURING THE FEBRUARY EVENT.

A. Our safe and reliable electric and gas systems across Colorado performed very well and as designed during the historic weather and market event. Our priority is to take prudent and necessary steps to ensure our utility services continue to be provided to customers. As I explained earlier, despite the extraordinary events, Black Hills did not lose service to its customers. This tremendous result was supported by round-the-clock monitoring of portions of our system to avoid freeze offs. Black Hills staged technicians at critical sites to ensure proper adjustments could be made to prevent interruptions to our customers' natural gas service.

We have a public obligation and requirement to keep the electrons and gas flowing in a safe and reliable manner. Safety and reliability are of the upmost importance to Black

Hills. Widespread loss of energy can have significant and detrimental impacts to the communities we proudly serve. Tragically, some states with widespread outages experienced loss of life related to the extreme weather. Reliability keeps the lights on and the gas flowing. Black Hills stands behind the efforts of its operational employees to meet customers' energy needs and ensure safe and reliable service and we take this obligation to serve very seriously.

Q. HOW DOES BLACK HILLS' INVEST IN ITS SYSTEM TO ENSURE SAFETY AND RELIABILITY?

A. The quality of our reliability of service is aided by our system upgrades, replacements, and expansions. Black Hills undertakes prudent investments to support its reliability of service. These investments are taken over the long term to support our customers. In particular, Black Hills has been in a period of significant natural gas system integrity investments, which contribute to day-to-day system integrity and reliability, especially in frigid temperatures. Without these investments, the Black Hills gas and electric systems could fail to provide critical energy to our customers during abnormal events such as the February Event.

Q. DID THE COMPANY INTERRUPT ITS SERVICE TO CUSTOMERS DURING THE FEBRUARY EVENT?

A. No. BHCG's Large Commercial customers in Base Rate Area 3 can receive interruptible service pursuant to Colo. PUC No. 1 Sheet Nos. 21 and 22. Sheet No. R6 defines interruption as "the Company's inability to provide distribution to an End-User due to constraints on the pipeline system." Interruptions under these tariff sheets in service are specifically tied to shortage of supply or constraints on the Company's system. There was no shortage of supply or constraints on the Company's system that would have allowed interruptions under the tariff.

BHCG has five Large Commercial customers currently taking interruptible service under Sheet No. 21, and the average monthly load for 2020 for all five customers is 535 Dth. BHCG has one Large Commercial customer currently taking interruptible service under Sheet No. 22, but that customer did not consume any gas during the February Event. BHCG currently has no interruptible agreements with any of the customers taking service under Sheet Nos. 21 and 22.

Q. COULD THE COMPANY LAUNCH ROLLING BLACKOUTS OF ITS NATURAL GAS SYSTEM TO FORCE CUSTOMERS TO CONSERVE ENERGY?

A. No. The natural gas system does not work like the electric grid in terms of allowing rolling blackouts. Recently the Company's natural gas system in Aspen, Colorado was vandalized causing a disruption of gas to the City of Aspen. The Company had to isolate the system in Aspen, which in turn left Aspen customers without natural gas. The Company had to carefully and safely repressurize the system and in turn go door to door and relight customers' appliances. Approximately 200 technicians worked around the clock to reconnect customers. These technicians consisted of Company personnel from our neighboring territories, Xcel Energy, and three different contractors. I explain this Aspen event to illustrate the impossibility of ceasing natural gas service to customers, such as by using a rolling black out approach. Any Company efforts to institute rolling natural gas blackouts would have sustained long-term impacts to customers, likely far outside and greater than the limited February Event.

VI. NATURAL GAS PURCHASES

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NATURAL GAS PURCHASES DURING THE EVENT.

A. BHCG provides natural gas public utility services to approximately 198,000 retail customers in numerous areas throughout the State of Colorado. The Company has approximately 183,000 residential customers and 15,000 commercial or other non-residential customers in its Colorado service area. As explained by Mr. Bauer, to procure sufficient natural gas supplies to meet the needs of these customers, BHCG approaches the process of its purchasing gas supply with three goals in mind. First, BHCG strives to be a reasonably-priced provider of natural gas in its service territory. Second, BHCG is committed to ensuring a high level of reliability. This means that, for those customers who are paying for firm natural gas service, especially residential and commercial customers who depend on the service to heat their homes and businesses, the gas will be there even during the coldest temperatures. Finally, BHCG employs tools within its portfolio management plan to mitigate price volatility in its supply portfolio to maintain a level of cost stability for its customers.

During the February Event, BHCG used a combination of baseload purchases, storage withdrawals, daily firm peaking contracts, and daily/spot market purchases. Mr. Bauer discusses each of these categories in more detail in his Direct Testimony.

Q. IN WHAT WAYS WAS THE COMPANY ABLE TO MITIGATE THE IMPACTS OF THE NATURAL GAS PURCHASES AND COSTS?

A. BHCG's primary obligation is to supply safe and reliable natural gas service to its customers. During the extreme cold temperatures of the February Event, BHCG was able to provide this service because it had procured sufficient natural gas supplies. The Company's proactive and diligent efforts in contracting a diversified portfolio of supply resources greatly mitigated the impacts of the natural gas price spike. This diversified supply was comprised of baseload, storage, daily spot purchases (including both ratable and non-ratable), and firm peaking. The baseload, storage, non-ratable daily, and firm peaking contracts provided considerable price protection to BHCG customers for the volatile market pricing during the February Event. These contracts provided customers with the following customer savings: baseload ($39.2 million), storage ($18.4 million), non-ratable ($8.8 million), and firm peaking ($1.4 million). Black Hills' efforts thus saved customers approximately $67.8 million.

VII. <u>REQUEST FOR GAS COST RECOVERY</u>

Q. HOW DOES THE COMPANY NORMALLY RECOVER ITS GAS COSTS?

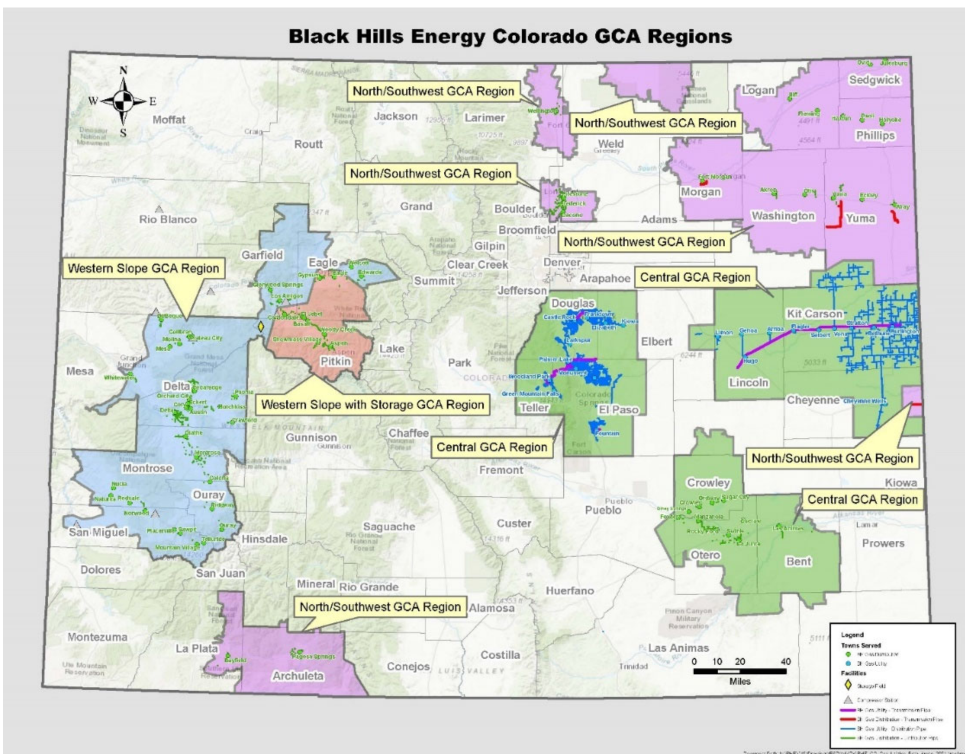
A. The cost of natural gas is a pass-through cost, meaning the cost incurred by the Company is directly passed on to customers. The Company does not profit on the cost of natural gas. Rather, as approved by the Commission, the Company passes the cost, dollar for dollar, on to its customers. The Company recovers its natural gas cost through an adjustment mechanism called the GCA. The GCA is a volumetric charge applicable to all rate schedules. The Company files annual updates to the GCA pursuant to Commission rules[11] and its tariffs.[12] Normally, the Company files annual revisions to the GCA to be effective

[11] Code of Colorado Regulations, Rules Regulating Gas Utilities and Pipeline Operators, 4 CCR 723-4, sections 4600 through 4609.
[12] BHCG Tariff First Revised Sheet Nos. 62-65.

on November 1st to reflect increases or decreases in gas costs and to true-up previous over or under collected gas costs.

The Company has three GCA regions: Central, North/Southwest, and Western Slope (including storage). The specific GCA rates vary by region due to different upstream pipeline and commodity costs. The figure below provides a map of the various GCA regions. In this application, the Company is providing specific cost information by GCA region. The February Event impacted each GCA region in slightly differently ways.

Figure MJH-1



Q. IS THE COMPANY ADDRESSING A DIFFERENT RECOVERY PROCESS FOR THE COST INCURRED DURING THE FEBRUARY EVENT?

A. Yes. The Company has separately tracked the extraordinary cost associated with the February Event as directed by the Commission. In Decision No. C21-0179, the Commission required the utilities to track and record the extraordinary costs from the

February Event for the purpose of discrete methods for cost recovery in separate, utility-specific proceedings.[13] The Commission also stated in this decision that:

> The investor-owned electric and natural gas utilities that are parties to this Proceeding are precluded from including the extraordinary costs of the February extreme weather event for recovery through the normal course of the implementation of their Electric Commodity Adjustment or Energy Cost Adjustment rate mechanisms and their Gas Cost Adjustment rate mechanisms.[14]

The Commission precluded the Company from including the "extraordinary" costs from the February Event through the normal course of updating the GCA. The Commission did not define "extraordinary," nor did it define how specifically these extraordinary costs should be recovered. The Commission deferred these issues to the specific utility filings as the definition and cost recovery treatment may be different for each utility based on the different circumstances of each utility.

In compliance with the Commission requirements, the Company has separately identified the extraordinary costs, and it is seeking, with this application, specific cost recovery treatment of those costs. The specific details are discussed below.

Q. WHAT ARE THE SPECIFIC DATES ASSOCIATED WITH THE FEBRUARY EVENT.

A. The Company is isolating the February Event to the specific days of Saturday February 13, 2021 through Wednesday February 17, 2021. During these days the market price of natural gas rose dramatically to unprecedented levels. As shown in the table below, the prices for natural gas started to rise on the 11th, but dramatically spiked during the 13th through the 17th. Prices began to substantially decrease on the 18th and returned wholly to pre-spike

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[13] Proceeding No. 21M-0130EG, Decision No. C21-0179 at Ordering ¶ 8.
[14] *Id.* at Ordering ¶ 9.

prices on the 20th. While the prices on the 12th and the 18th are certainly high, the Company does not consider these prices as extraordinary, especially in light of the prices that occurred during February 13-17. During the 2014 Polar Vortex[15] event, prices rose to roughly $35/dth at the Cheyenne Hub. Thus, the prices on the 12th and the 18th were within the ranges of previous cold weather events. The Company considers the prices from the 13th through the 17th as extraordinary.

[15] In late January and early February of 2014, the area from Chicago to the Northeast experienced severely cold temperatures for a sustained amount of time.

Table MJH-2: February Natural Gas Prices

Feb. 2021	Chey Hub	CIG Rockies	EP Bondad	Kern River Opal	White River Hub
1	2.565	2.565	2.580	2.650	2.580
2	2.655	2.660	2.680	2.685	2.660
3	2.830	2.805	2.810	2.845	2.815
4	2.805	2.760	2.780	2.815	2.795
5	2.875	2.835	2.785	2.830	2.830
6	3.490	3.490	3.410	3.540	3.475
7	3.490	3.490	3.410	3.540	3.475
8	3.490	3.490	3.410	3.540	3.475
9	3.415	3.395	3.295	3.390	3.355
10	3.475	3.460	3.305	3.390	3.365
11	5.635	4.825	4.285	4.490	4.805
12	14.840	13.285	10.695	10.420	12.140
13	**187.690**	**172.945**	**79.355**	**85.560**	**139.455**
14	**187.690**	**172.945**	**79.355**	**85.560**	**139.455**
15	**187.690**	**172.945**	**79.355**	**85.560**	**139.455**
16	**187.690**	**172.945**	**79.355**	**85.560**	**139.455**
17	**92.595**	**78.200**	**186.540**	**160.840**	**106.725**
18	20.440	19.525	27.190	20.000	19.815
19	5.810	5.785	6.255	5.405	5.955
20	3.730	3.655	3.755	3.650	3.770
21	3.730	3.655	3.755	3.650	3.770
22	3.730	3.655	3.755	3.650	3.770
23	2.650	2.665	2.660	2.810	2.705
24	2.700	2.700	2.715	2.785	2.685
25	2.630	2.630	2.680	2.750	2.650
26	2.485	2.480	2.425	2.580	2.440
27	2.485	2.480	2.425	2.580	2.440
28	2.485	2.480	2.425	2.580	2.440

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S REQUEST FOR GAS COST RECOVERY.

A. As discussed above, the Company is isolating the February Event to the specific days of Saturday February 13, 2021 through Wednesday February 17, 2021. During this timeframe the Company incurred a <u>total</u> cost of natural gas of $75,692,864. This amount represents approximately 70% of the Company's typical, annual cost of natural gas.

As directed by the Commission, the Company has isolated the "extraordinary" cost associated with the February Event. Below, the Company presents several methods for determining what is considered "extraordinary." Based on the Company's preferred method, the extraordinary costs associated with the February Event are $72,666,626.

The extraordinary costs will not be addressed in the normal GCA process; rather, they will be treated separately. As discussed in greater detail below, the Company is proposing to amortize the extraordinary costs over one year for the Western Slope GCA Region and three years for Central and North/Southwest GCA Regions. These amortizations are proposed to be effective on November 1, 2021, which is when the next GCA is scheduled to be updated.

The Company has incurred additional debt cost associated with the February Event. The Company is thus proposing to include a carrying cost on the unamortized balance equal to the Company's weighted average cost of long-term debt for the GCA regions that generally reflect the length of the amortization period.

Q. THE ATTORNEY GENERAL OF COLORADO SENT A LETTER TO THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC") ENCOURAGING FERC TO EXAMINE WHOLESALE NATURAL GAS

MARKET ACTIVITY. IF BLACK HILLS RECEIVES REFUNDS AS A RESULT OF THAT INVESTIGATION OR OTHER INVESTIGATIONS, WILL THE COMPANY PASS THOSE SAVINGS ON TO CUSTOMERS?

A. Yes. To the extent that any efforts at FERC or elsewhere result in damages or refunds being awarded to Black Hills related to February Event gas costs, Black Hills will ensure those savings are passed on to its customers. The cost of natural gas is a pass-through cost to our customers. Any savings the Company receives from investigations will also be passed on to customers.

A. FEBRUARY EVENT TOTAL COST

Q. PLEASE PROVIDE THE TOTAL COST INCURRED FOR THE FEBRUARY EVENT.

A. Mr. Bauer provides a detailed explanation of the gas purchases in his testimony. The total cost incurred by BHCG during the February Event was $75,692,864. This cost includes the daily (spot) purchases, baseload purchases, and storage. The confidential table below provides the detailed cost by day and by GCA Regions. This information is also contained in Confidential Attachment MJH-1.

Confidential Table MJH-3: February Event Total Cost By GCA Region

Description	Central GCA Region BHCOG	Central GCA Region Arkansas Valley	North/Southwest GCA Region North Central	North/Southwest GCA Region North Eastern	North/Southwest GCA Region Southwestern	Western Slope Region	Total BHCG
Daily Purchases							
Feb 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 18,930,851
Feb 14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	19,237,695
Feb 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	17,014,335
Feb 16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	12,693,330
Feb 17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6,834,731
Total	$ 39,430,667	$ 4,781,760	$ 12,593,813	$ 3,719,697	$ 1,000,831	$ 13,184,175	$ 74,710,941
Baseload Costs							
Feb 13	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 153,743
Feb 14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	153,743
Feb 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	153,743
Feb 16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	153,743
Feb 17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	153,743
Total	$ 299,305	$ 31,521	$ 56,870	$ 22,989	$ 24,528	$ 333,500	$ 768,713
Storage Costs							
Feb 13	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 41,627
Feb 14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76,327
Feb 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	25,139
Feb 16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	28,606
Feb 17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	41,510
Total	73,537	37,178	-	12,495	-	90,000	213,210
Total Costs	**$ 39,803,509**	**$ 4,850,459**	**$ 12,650,683**	**$ 3,755,180**	**$ 1,025,358**	**$ 13,607,675**	**$ 75,692,864**

B. FEBRUARY EVENT EXTRAORDINARY COST

Q. DID THE COMMISSION PROVIDE A DEFINITION OF EXTRAORDINARY COST?

A. No. The Commission has not provided the Company with a definition of extraordinary cost, but rather the Commission left it up to the utilities to propose a definition.

Q. DID THE COMPANY CONSIDER DIFFERENT METHODS FOR DETERMINING THE EXTRAORDINARY COSTS INCURRED?

A. Yes. The Company considered four different methods to determine what is considered extraordinary cost.

<u>Method 1: Actual Spot Market Purchases</u>

First, the Company considered determining extraordinary costs as related to purchases on the daily spot market. The Company's base load and storage purchases were excluded as those were not impacted by the extraordinarily high gas prices. The total daily spot market purchases for the specific days during the February Event were $74,710,941. The amount by GCA Region is shown in the table below as well as in Attachment MJH-1.

Table MJH-4: Daily Spot Market Purchases

Central GCA Region		North/Southwest GCA Region			Western Slope	
BHCOG	Arkansas Valley	North Central	North Eastern	Southwestern	Region	Total BHCG
$39,430,667	$4,781,760	$12,593,813	$3,719,697	$1,000,831	$13,184,175	**$74,710,941**

Method 2: GCA Status Quo

Second, the Company considered the total February 2021 monthly gas cost less the total February 2021 monthly GCA revenues. This is the "status quo" method under the GCA. While the Company has cost information by day, the Company does not have detailed customer usage information by day. Thus, it is difficult to estimate the GCA revenues by day. The GCA revenues received during the month of February reflect the increased usage during the February Event, but are also based on the existing GCA rate. Examining the total monthly cost less the total monthly revenues demonstrates the magnitude of the extraordinarily high market prices compared to what the Company collected in revenues using the existing GCA rate. The difference between the total February monthly cost less the total February monthly revenues is $74,339,603. The amount by GCA Region is shown in the table below as well as in Attachment MJH-1.

Table MJH-5:Total February Cost Less Revenues

Central GCA Region		North/Southwest GCA Region			Western Slope	
BHCOG	Arkansas Valley	North Central	North Eastern	Southwestern	Region	Total BHCG
$39,489,656	$4,773,231	$12,882,665	$3,624,826	$1,023,897	$12,545,328	**$74,339,603**

<u>Method 3: Three-Year Historical Average</u>

Third, the Company compared the total February 2021 gas cost to a three-year historical average. The total gas cost for the month of February was $91,393,050, while the three-year historical average cost for the month of February is $13,469,450. This provides a difference of $77,923,600. The amount by GCA Region is shown in the table below as well as in Attachment MJH-1.

Table MJH-6: Total February Cost Less Three-year Historical Average

Central GCA Region		North/Southwest GCA Region			Western Slope	
BHCOG	Arkansas Valley	North Central	North Eastern	Southwestern	Region	Total BHCG
$40,601,009	$4,988,430	$13,348,956	$3,824,260	$1,087,793	$14,073,152	**$77,923,600**

<u>Method 4: Repriced Daily Spot Market Purchases</u>

Fourth, the Company repriced the daily spot market purchases for the February Event. As discussed in the first method, the total daily spot market purchases were $74,710,941. The Company repriced these purchases using an average price for each GCA region (ranging from $4.28-$4.58/Dth) for the month of February that excludes the prices during the February Event. The difference between the repriced spot market purchases and the total spot market purchases is $72,666,626. The amount by GCA Region is shown in the table below as well as in Attachment MJH-1.

Table MJH-7: Daily Spot Market Repriced

Central GCA Region		North/Southwest GCA Region			Western Slope	
BHCOG	Arkansas Valley	North Central	North Eastern	Southwestern	Region	Total BHCG
$38,394,267	$4,659,635	$12,278,222	$3,625,732	$955,933	$12,752,836	$72,666,626

Q. WHAT METHOD IS THE COMPANY PROPOSING TO USE?

A. BHCG is proposing to use method four, involving the repriced daily spot market purchases. This method is the best representation of what the GCA would have experienced if not for the February Event. The amount will be amortized over a period of time as described below, which will assist in mitigating customer bill impacts. To be clear, the total cost incurred during the February Event was $75,692,864. Of this cost, the extraordinary cost portion according to the Company's preferred definition of extraordinary cost is $72,666,626. The remaining cost—$3,026,238—is not considered extraordinary, and it will be included in the Company's next GCA filing.

Table MJH-8: Summary of Methods

Proposed Method	Cost to be Recovered
Method 1: Actual Spot Market Purchases	$74,710,941
Method 2: Status Quo	$74,339,603
Method 3: Three Year Historic Average	$77,923,600
Method 4: Repriced Daily Spot Market Purchases	$72,666,626

C. AMORTIZATION PERIOD

Q. WHAT IS THE COMPANY'S OBJECTIVE IN DETERMINING AN APPROPRIATE AMORTIZATION PERIOD?

A. The extraordinary cost associated with the February Event present several challenges for the Company and the Commission to consider. Including the cost in the normal GCA process, which is recovered from customers over a 12-month period, would lead to greatly increased bills. Recovery of the February Event cost over a one-year period would almost double the currently effective GCA rate in the North/Southwest GCA Region. However, the benefit of a one-year amortization period is that the Company would be able to recover the cost in the normal course of business and would not have the need to incur additional carrying cost.

Longer amortization periods beyond one-year present other challenges. Long amortization periods introduce intergenerational inequities among customers. With long amortization periods, new customers who join the system well after the February Event could be subject to cost recovery for an event they were not a part of. Also, long amortization periods require the Company to incur additional carrying cost. As discussed below, the Company has already incurred additional debt cost and long amortization periods may also cause the Company to incur additional long-term debt while balancing the Company's capitalization ratios.

The Company is striving to find the right balance for the amortization period. The Company is concerned about bill impacts and the challenges that a short amortization period would have on customers. Short amortization periods will lead to a higher rate, which will increase customer bills. On the other side, the Company is also concerned about long amortization periods. From a financial perspective, long amortization periods will require the Company to incur additional long-term debt while balancing capitalization ratios. Also, long amortization periods present policy concerns regarding intergenerational inequities.

Q. WHAT DIFFERENT AMORTIZATION PERIODS DID THE COMPANY ANALYZE?

A. The Company analyzed several different amortization periods. As directed by the Commission in Decision No. C21-0261, Ordering Paragraph 32, BHCG prepared amortization periods using:

1. 24 months and no carrying costs;

2. 60 months with carrying costs recovered from ratepayers calculated at the utility's weighted average cost of long-term debt; and

3. 84 months with carrying costs recovered from ratepayers calculated at the cost of senior secured bonds rated "AA" or "AA2" or better by at least one major independent credit rating agency or some other reasonable measure of financing the amortization through securitization.

BHCG also separately prepared four additional amortization periods using:

4. 8 months of short-term debt followed by 12 months with carrying costs recovered from customers without interest;

5. 8 months of short-term debt followed by 24 months with carrying costs recovered from customers calculated at the utility's weighted average cost of long-term debt;

6. 8 months of short-term debt followed by 36 months with carrying costs recovered from customers calculated at the utility's weighted average cost of long-term debt; and

7. 8 months of short-term debt followed by 36 months with carrying costs recovered from customers calculated at the utility's weighted average cost of capital.

Table MJH-9 provides a side-by-side comparison of the various amortization scenarios. The detailed calculations are provided in Attachment MJH-2. As shown in the table below, the seven-year securitization scenario is the costliest scenario. I discuss securitization in greater detail later in my testimony. I also describe further below the customer bill impacts associated with each amortization scenario below.

Table MJH-9: Amortization Scenarios

	Decision No. C21-0261 Scenarios Ordering Paragraph 32			BHCG Scenarios			
Scenario	1	2	3	4	5	6	7
Amortization Period	2 years	5 years	7 years	1 year	2 years	3 years	4 years
Description	24 months	60 months	84 months	12 months	24 months	36 months	36 months
Short-term Interest	No Interest	8 months STD	8 months STD	8 months STD	8 months STD	8 months STD	8 months STD
Long-term Interest	No Interest	WACLTD[1]	Securitization	No LTD	WACLTD[1]	WACLTD[1]	WACC
Total Short Term Interest	$ -	$ 454,203	$ -	$ 454,203	$ 454,203	$ 454,203	$ 454,203
Total Long Term Interest	$ -	$ 7,498,988	$ 10,837,042	$ 0	$ 3,015,284	$ 4,491,284	$ 7,623,983
Total Principal	$ 72,666,626	$ 72,666,626	$ 72,666,626	$ 72,666,626	$ 72,666,626	$ 72,666,626	$ 72,666,626
Grand Total	$ 72,666,626	$ 80,619,817	$ 83,503,669	$ 73,120,829	$ 76,136,113	$ 77,612,113	$ 80,744,812

Note 1: Weighted Average Cost of Long-term Debt ("WACLTD")
Note 2: Weighted Average Cost of Capital ("WACC")

Q. WHAT AMORTIZATION PERIOD IS THE COMPANY PROPOSING?

A. The Company is proposing a three-year amortization period for Central and North/Southwest GCA regions (Scenario 6) and a one-year amortization period for the Western Slope GCA region (Scenario 4). The proposed recovery periods strike an appropriate balance reflecting both customer bill impacts and the Company's incurred carrying costs. The customer bill impacts for each scenario are shown below.

D. CARRYING COST

Q. IS THE COMPANY PROPOSING TO INCLUDE CARRYING COST ON THE EXTRAORDINARY COST?

A. Yes. For Central and North/Southwest GCA regions, the Company is including both short-term carrying cost and long-term carrying cost. As discussed later in my testimony, the Company issued a short-term nine-month loan to address the short-term liquidity issues stemming from the February Event. This term loan will be refinanced into long-term debt on or before the maturity date that takes place in November 2021. The Company has included the short-term carrying cost of this note in its cost recovery proposals until November.

In addition, because the Company is proposing to recover the cost associated with the February Event over a three-year period (for the Central and North/Southwest GCA regions), the Company will rely on longer-term financing options like long-term debt. The carrying costs are appropriate and needed to facilitate the extended recovery of costs, which mitigate customer bill impacts. The Company is proposing to include long-term carrying cost equal to the weighted average cost of long-term debt.

For the Western Slope GCA region, the Company is proposing to include short-term carrying cost for eight months (for the time until November) and a twelve-month amortization period thereafter with no additional carrying costs. This different treatment is appropriate because the bill impacts for this region are similar to the Central and North/Southwest GCA regions.

E. CUSTOMER BILL IMPACTS

Q. PLEASE PROVIDE THE VARIOUS CUSTOMER BILL IMPACTS ASSOCIATED WITH THE DIFFERENT AMORTIZATION PERIODS.

A. The Company presents multiple bill impact scenarios associated with different amortization periods as discussed above. The table below provides the bill impacts for a residential and small commercial customer on the various scenarios. The calculations are provided in Attachment MJH-2: Amortization & Bill Impacts.

Table MJH-10: Bill Impact Analysis By Scenario

Scenario 1: 24 months and no carrying costs				
Principal	$ 72,666,626			
Interest	0			
Total	$ 72,666,626			
	Central GCA Region	**North/Southwest GCA Region**	**Western Slope (with Storage)**	**Western Slope (without Storage)**
Residential				
Base Rate Area 1- Amount		$21.74	$6.19	$6.19
Base Rate Area 1- Percentage		**28.67%**	**7.21%**	**7.59%**
Base Rate Area 1- Total		$521.76	$148.56	$148.56
Base Rate Area 2- Amount	$11.30	$14.91		
Base Rate Area 2- Percentage	**22.96%**	**25.39%**		
Base Rate Area 2- Total	$271.20	$357.84		
Base Rate Area 3- Amount	$16.47			
Base Rate Area 3- Percentage	**30.37%**			
Base Rate Area 3- Total	$395.28			
Small Commercial				
Base Rate Area 1- Amount		$44.74	$12.74	$12.74
Base Rate Area 1- Percentage		**30.49%**	**7.61%**	**8.04%**
Base Rate Area 1- Total		$1,073.76	$305.76	$305.76
Base Rate Area 2- Amount	$27.39	$36.15		
Base Rate Area 2- Percentage	**27.00%**	**29.04%**		
Base Rate Area 2- Total	**30.49%**	**30.49%**		
Base Rate Area 3- Amount	$25.29			
Base Rate Area 3- Percentage	**30.89%**			
Base Rate Area 3- Total	$606.96			

Scenario 2: 60 months, 8 months of Short-term debt & weighted average cost of long-term debt				
Principal	$ 73,120,829			
Interest	7,498,988			
Total	$ 80,619,817			
	Central GCA Region	**North/Southwest GCA Region**	**Western Slope (with Storage)**	**Western Slope (without Storage)**
Residential				
Base Rate Area 1- Amount		$9.65	$2.75	$2.75
Base Rate Area 1- Percentage		**12.72%**	**3.20%**	**3.37%**
Base Rate Area 1- Total		$579.00	$165.00	$165.00
Base Rate Area 2- Amount	$5.02	$6.62		
Base Rate Area 2- Percentage	**10.20%**	**11.27%**		
Base Rate Area 2- Total	$301.20	$397.20		
Base Rate Area 3- Amount	$7.31			
Base Rate Area 3- Percentage	**13.48%**			
Base Rate Area 3- Total	$438.60			
Small Commercial				
Base Rate Area 1- Amount		$19.85	$5.66	$5.66
Base Rate Area 1- Percentage		**13.53%**	**3.38%**	**3.57%**
Base Rate Area 1- Total		$1,191.00	$339.60	$339.60
Base Rate Area 2- Amount	$12.16	$16.04		
Base Rate Area 2- Percentage	**11.99%**	**12.89%**		
Base Rate Area 2- Total	$729.60	$962.40		
Base Rate Area 3- Amount	$11.22			
Base Rate Area 3- Percentage	**13.70%**			
Base Rate Area 3- Total	$673.20			

Scenario 3: 84 months,8 months short-term debt & securitization				
Principal	$ 73,120,829			
Interest	10,858,584			
Total	$ 83,979,414			
	Central GCA Region	**North/Southwest GCA Region**	**Western Slope (with Storage)**	**Western Slope (without Storage)**
Residential				
Base Rate Area 1- Amount		$7.18	$2.04	$2.04
Base Rate Area 1- Percentage		**9.47%**	**2.38%**	**2.50%**
Base Rate Area 1- Total		$603.12	$171.36	$171.36
Base Rate Area 2- Amount	$3.73	$4.92		
Base Rate Area 2- Percentage	**7.58%**	**8.38%**		
Base Rate Area 2- Total	$313.32	$413.28		
Base Rate Area 3- Amount	$5.44			
Base Rate Area 3- Percentage	**10.03%**			
Base Rate Area 3- Total	$456.96			
Small Commercial				
Base Rate Area 1- Amount		$14.77	$4.21	$4.21
Base Rate Area 1- Percentage		**10.07%**	**2.52%**	**2.66%**
Base Rate Area 1- Total		$1,240.68	$353.64	$353.64
Base Rate Area 2- Amount	$9.04	$11.93		
Base Rate Area 2- Percentage	**8.91%**	**9.58%**		
Base Rate Area 2- Total	$759.36	$1,002.12		
Base Rate Area 3- Amount	$8.35			
Base Rate Area 3- Percentage	**10.20%**			
Base Rate Area 3- Total	$701.40			

Scenario 4: 12 months, 8 months of short-term debt, no long-term interest as of Nov 1, 2021				
Principal	$ 73,120,829			
Interest	0			
Total	$ 73,120,829			
	Central GCA Region	**North/Southwest GCA Region**	**Western Slope (with Storage)**	**Western Slope (without Storage)**
Residential				
Base Rate Area 1- Amount		$43.75	$12.46	$12.46
Base Rate Area 1- Percentage		**57.69%**	**14.51%**	**15.29%**
Base Rate Area 1- Total		$525.00	$149.52	$149.52
Base Rate Area 2- Amount	$22.75	$30.01		
Base Rate Area 2- Percentage	**46.22%**	**51.11%**		
Base Rate Area 2- Total	$273.00	$360.12		
Base Rate Area 3- Amount	$33.15			
Base Rate Area 3- Percentage	**61.12%**			
Base Rate Area 3- Total	$397.80			
Small Commercial				
Base Rate Area 1- Amount		$90.04	$25.65	$25.65
Base Rate Area 1- Percentage		**61.36%**	**15.33%**	**16.19%**
Base Rate Area 1- Total		$1,080.48	$307.80	$307.80
Base Rate Area 2- Amount	$55.13	$72.74		
Base Rate Area 2- Percentage	**54.35%**	**58.44%**		
Base Rate Area 2- Total	$661.56	$872.88		
Base Rate Area 3- Amount	$50.89			
Base Rate Area 3- Percentage	**62.15%**			
Base Rate Area 3- Total	$610.68			

Scenario 5: 24 months, 8 months short-term debt & weighted average cost of long-term debt				
Principal	$ 73,120,829			
Interest	3,015,284			
Total	$ 76,136,113			
	Central GCA Region	**North/Southwest GCA Region**	**Western Slope (with Storage)**	**Western Slope (without Storage)**
Residential				
Base Rate Area 1- Amount		$22.78	$6.49	$6.49
Base Rate Area 1- Percentage		**30.04%**	**7.56%**	**7.96%**
Base Rate Area 1- Total		$546.72	$155.76	$155.76
Base Rate Area 2- Amount	$11.84	$15.63		
Base Rate Area 2- Percentage	**24.06%**	**26.62%**		
Base Rate Area 2- Total	$284.16	$375.12		
Base Rate Area 3- Amount	$17.26			
Base Rate Area 3- Percentage	**31.82%**			
Base Rate Area 3- Total	$414.24			
Small Commercial				
Base Rate Area 1- Amount		$46.88	$13.35	$13.35
Base Rate Area 1- Percentage		**31.95%**	**7.98%**	**8.43%**
Base Rate Area 1- Total		$1,125.12	$320.40	$320.40
Base Rate Area 2- Amount	$28.70	$37.87		
Base Rate Area 2- Percentage	**28.29%**	**30.42%**		
Base Rate Area 2- Total	$688.80	$908.88		
Base Rate Area 3- Amount	$26.49			
Base Rate Area 3- Percentage	**32.35%**			
Base Rate Area 3- Total	$635.76			

Scenario 6: 36 months, 8 months short-term debt & weighted average cost of long-term debt				
Principal	$ 73,120,829			
Interest	4,491,284			
Total	$ 77,612,113			
	Central GCA Region	**North/Southwest GCA Region**	**Western Slope (with Storage)**	**Western Slope (without Storage)**
Residential				
Base Rate Area 1- Amount		$15.48	$4.41	$4.41
Base Rate Area 1- Percentage		**20.41%**	**5.14%**	**5.41%**
Base Rate Area 1- Total		$557.28	$158.76	$158.76
Base Rate Area 2- Amount	$8.05	$10.62		
Base Rate Area 2- Percentage	**16.36%**	**18.09%**		
Base Rate Area 2- Total	$289.80	$382.32		
Base Rate Area 3- Amount	$11.73			
Base Rate Area 3- Percentage	**21.63%**			
Base Rate Area 3- Total	$422.28			
Small Commercial				
Base Rate Area 1- Amount		$31.86	$9.07	$9.07
Base Rate Area 1- Percentage		**21.71%**	**5.42%**	**5.73%**
Base Rate Area 1- Total		$1,146.96	$326.52	$326.52
Base Rate Area 2- Amount	$19.51	$25.74		
Base Rate Area 2- Percentage	**19.23%**	**20.68%**		
Base Rate Area 2- Total	$702.36	$926.64		
Base Rate Area 3- Amount	$18.00			
Base Rate Area 3- Percentage	**21.98%**			
Base Rate Area 3- Total	$648.00			

Scenario 7: 36 months,8 months short-term & weighted average cost of capital				
Principal	$ 73,120,829			
Interest	7,623,983			
Total	$ 80,744,812			
	Central GCA Region	North/Southwest GCA Region	Western Slope (with Storage)	Western Slope (without Storage)
Residential				
Base Rate Area 1- Amount		$16.10	$4.59	$4.59
Base Rate Area 1- Percentage		**21.23%**	**5.35%**	**5.63%**
Base Rate Area 1- Total		$579.60	$165.24	$165.24
Base Rate Area 2- Amount	$8.37	$11.05		
Base Rate Area 2- Percentage	**17.01%**	**18.82%**		
Base Rate Area 2- Total	$301.32	$397.80		
Base Rate Area 3- Amount	$12.20			
Base Rate Area 3- Percentage	**22.49%**			
Base Rate Area 3- Total	$439.20			
Small Commercial				
Base Rate Area 1- Amount		$33.14	$9.44	$9.44
Base Rate Area 1- Percentage		**22.59%**	**5.64%**	**5.96%**
Base Rate Area 1- Total		$1,193.04	$339.84	$339.84
Base Rate Area 2- Amount	$20.29	$26.78		
Base Rate Area 2- Percentage	**20.00%**	**21.51%**		
Base Rate Area 2- Total	$730.44	$964.08		
Base Rate Area 3- Amount	$18.73			
Base Rate Area 3- Percentage	**22.87%**			
Base Rate Area 3- Total	$674.28			

Q. WHAT OBSERVATIONS DO YOU HAVE ON THE VARIOUS SCENARIOS?

A. These scenarios present the Commission multiple assessments of customer bill impacts. Given the Company's multiple GCA regions, as well as base rate areas, there are a multitude and sometimes competing bill impact scenarios to review.

More globally, shorter amortization periods reduce the amount of interest that is owed; however, they result in higher customer bill impacts. Scenario 4 is the shortest amortization period and has the highest bill impact. The Securitization Scenario (Scenario 3) results in the lowest customer bill impact, but it is amortized over a longer time period of 84 months. This scenario also has the highest overall cost to customers. A three-year amortization for the Central and North/Southwestern GCA regions as shown in Scenario 6 results in residential customer bill impacts ranging from a 16% to a 21% bill increase over a three-year time period. It is also notable the Western Slope GCA region was not impacted to the same degree that the other regions were.

The Company is proposing Scenario 6 for the Central and North/Southwestern GCA regions. Scenario 6 balances both customer bill impacts and carrying costs. Scenario 6 involves a shorter time period of amortization than other scenarios (such as securitization), and it results in a reasonable bill impact.

For the Western Slope GCA region, the Company is proposing Scenario 4. This is the reasonable scenario for this region, as the bill impacts under Scenario 4 are consistent with that of Scenario 6 for the Central and North/Southwestern GCA regions. Scenario 4 also avoids the need for long-term financing for this region.

It is important for the Commission to consider that extending the amortizations beyond a period of three years should reflect application of the Company's WACC, as WACC more properly reflects the true cost to the Company of long amortization periods.

F. RATE DESIGN

Q. IS THE COMPANY PROPOSING A NEW LINE ITEM ON CUSTOMER BILLS TO REFLECT THE EXTRAORDINARY COST ASSOCIATED WITH THE FEBRUARY EVENT?

A. Yes. The Company considered combining the February Event cost with the GCA cost to derive a combined total cost and calculate a resulting combined total rate. The combined total rate would appear as one line item on a customer's bill. The Company could still separately track the separate components, but customers would only see one line item on their bill. The existing GCA line item description provides rate and volume information so that customers can easily understand the charges on their bill. However, combining the February Event rate with the normal GCA rate would result in less transparency because the rate and volume information shown on the bill would not be available to the customer. For this reason, the Company is proposing to add a new line item on customer bills.

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN FOR THE FEBRUARY EVENT EXTRAORDINARY COSTS?

A. The Company is proposing a new line item on customer bills called the ECRR. The ECRR will be treated similar to the GCA but will be separately tracked from GCA costs. The ECRR will be charged on a volumetric basis. Determining the rate on a volumetric basis is a reasonable and easily understood approach that directly correlates with the manner the costs were incurred. In addition, the current GCA rates are volumetric and for consistency proposes a volumetric rate is appropriate. The Large Volume Interruptible class customer will not be billed for the February Event, as they had zero usage during the February Event.

Q. DID THE COMPANY CONSIDER OTHER RATE DESIGNS?

A. Yes. The Company also explored a rate design where a greater portion of cost recovery was assigned to summer volumes than winter volumes. The goal of this rate design would be to collect a greater portion of the revenue during the summer months when bills are typically lower than during the high usage winter months. This rate design would theoretically smooth out the overall billed revenue stream so customers are not affected with larger bill increases during high usage months. The primary reason the Company is not recommending the summer/winter differential rate design is that it requires very high volumetric rates during the summer months when class volumes are lowest. The high rates create definite winners and losers within less homogeneous customer classes such as the commercial rate classes. Higher load factor customers such as restaurants and hotels would likely be adversely impacted for cooking and pool/water heating during the high-rate summer months. In the end, the summer/winter differential rate design helps some customers and harms others in a way that is inconsistent with how the costs were originally incurred.

The better solution is to allow customers to self-select into the Company's available Budget Billing program to smooth out their bills. The Budget Billing program is available to customers on a 12-month basis. It achieves a very similar result to the Summer/Winter split rate design. The Company will inform customers of the Budget Billing option to smooth out their bills.

Q. WHEN IS THE COMPANY PROPOSING TO IMPLEMENT THE ECRR?

A. The Company proposes that cost recovery begin on November 1, 2021. This is the same time when the GCA is normally updated and costs associated with the February Event would have normally been recovered. In addition, the Company has several concerns that a lengthy delay in implementation could have unintended consequences, such as to the Company's credit rating (discussed below).

Q. HOW WILL THE COMPANY ENSURE THAT IT RECOVERS NO MORE OR LESS THAN THE TOTAL, EXTRAORDINARY COST?

A. The ECRR will be set and will not change throughout the amortization period. The Company will separately track the revenues generated from the ECRR. At the end of the amortization period, the Company will stop charging the ECRR. Any remaining net balance either positive or negative will then be included in the Company's next GCA true-up calculation.

Q. ARE YOU SPONSORING PRO FORMA TARIFF SHEETS TO RECOVER THE FEBRUARY EVENT GAS COST?

A. Yes. In Attachment MJH-3, I am providing *pro forma* tariff sheets necessary to support implementation of the ECRR. Following Commission approval of this Application, the Company will file a compliance Advice Letter implementing final tariff sheets consistent with the Commission's final decision.

VIII. <u>FINANCING & SECURITIZATION</u>

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The February Event caused BHCG and its other regulated affiliates within Black Hills Corporation to incur extraordinarily high gas costs. This section of my testimony describes the financing activities Black Hills has taken in response to the February Event. In addition, I discuss securitization financing and why that is not an appropriate tool to use for this event.

A. FINANCING COST

Q. DID THE FEBRUARY EVENT CREATE SHORT-TERM LIQUIDITY NEEDS FOR BLACK HILLS CORPORATION AND BHCG?

A. Yes. During the February Event, BHC incurred extraordinary gas costs across its various utilities of approximately $600 million. Over that same time period, BHCG incurred gas costs of $75,692,864, which is approximately 70% of the typical, annual gas costs. These gas costs became due and payable in March 2021.

Q. HOW DID BHC MANAGE ITS SHORT-TERM LIQUIDITY NEEDS?

A. BHC worked with its banking relationship and announced on February 24, 2021, the closing of an $800 million unsecured term loan maturing in nine-months on November 24, 2021, with an interest rate of LIBOR (London Inter-Bank Offered Rate) plus 75 basis points. The proceeds of this term loan were used to fund the natural gas purchases made in February 2021 (by its subsidiaries) and provide additional liquidity. It was important to quickly lock in low-cost financing in the short-term to manage liquidity before options potentially became more expensive or were altogether unavailable. The term loan allows BHC to pay down a portion or the entire loan with no prepayment penalty and provides important flexibility to determine the best options for BHC's subsidiaries before locking in more permanent solutions. The term loan is a short-term bridge loan that provided a source of short-term liquidity and allowed BHC and its subsidiaries to meet settlements without reducing regular sources of liquidity. This term loan also allowed the Company and its regulators time to understand the cost recovery period before committing to a more long-term solution. On March 31, 2021, BHC paid down a portion of the term loan to $600 million. BHC took this action once costs were more definite. The term loan is currently at a rate of 0.85613% until May 26, 2021, as it resets each month.

Q. HOW DOES THE COMPANY PLAN TO FINANCE THE EXTRAORDINARY COSTS OVER THE RECOVERY PERIOD?

A. The finance philosophy of BHCG is aligned with the overall corporate finance philosophy of BHC, which is to maintain financial integrity and ability to access capital as needed at all times at a reasonable cost. Funding will be provided through BHC and will depend on many factors including recovery time and requirements of funding for other BHC utilities. BHC issues long-term debt and equity to fund its utilities at the parent level to ensure the most efficient source of funding for all its business units. This financing approach lowers the cost of debt as compared to separate issuances of debt for each of the BHC utilities. Based on the outcomes of the various regulatory proceedings for its utilities, BHC anticipates that it will refinance the short-term unsecured term loan with a long-term note. The Company funds its long-term assets with both long-term debt and equity. The Company targets a 50/50 long-term debt to equity capital structure.

Q. IS THE COMPANY PROPOSING TO INCLUDE CARRYING COST EQUAL TO THE WEIGHTED AVERAGE COST OF CAPITAL?

A. No. As discussed above, it is likely BHC will have to issue long-term debt that balances our capitalization ratios to fund the long-term February Event regulatory asset. As means to help mitigate customer bill impacts and to absorb some of the cost associated with the February Event, the Company is not proposing to include carrying cost equal to its WACC. As shown in Scenario 7 above, the interest cost associated with a three-year amortization period using the Company's authorized WACC results in an additional $3.1 million of carrying cost. The Company is proposing to forgo this additional cost as a way to help mitigate the customer bill impacts. However, the Company is proposing to include a carrying cost that is equal to BHC's current weighted average cost of long-term debt. That being said, should the Commission seek an amortization period that is beyond three years, a carrying charge based on WACC would be appropriate, as that carrying charge would more appropriately reflect the cost to the Company of the longer amortization period.

Q. WHAT IS BHC'S CURRENT WEIGHTED AVERAGE LONG-TERM COST OF DEBT?

A. BHC's current weighted average cost of long-term debt is 3.91%.

Q. WILL THE WEIGHTED AVERAGE LONG-TERM COST OF DEBT CHANGE WHEN NEW LONG-TERM DEBT IS ADDED?

A. Yes. As I stated above, BHC secured short-term financing to address the immediate liquidity needs resulting from the exceptionally high expenses due to the February Event. Depending on GCA area, BHCG is proposing to amortize costs over a maximum three-year period, which will require the Company to secure additional long-term debt. The addition of the new long-term debt will change the Company's weighted average long-term cost of debt.

Q. WHY IS IT APPROPRIATE TO INCLUDE CARRYING COSTS USING BHC'S WEIGHTED AVERAGE COST OF LONG-TERM DEBT?

A. Because the Company is proposing to recover the costs associated with the February Event over a maximum three-year period, the Company will rely on longer-term financing options like long-term debt while managing capitalization ratios. The carrying costs are appropriate and needed to facilitate the extended recovery of costs, which mitigate customer bill impacts. Even if the Company is required to issue new equity to fund the February Event costs, the Company's proposal will provide customers with a more favorable carrying cost based on long-term debt, as compared to WACC.

Q. ARE UTILITY INVESTORS CONCERNED ABOUT THE REGULATORY TREATMENT OF THE EXTRAORDINARY FEBRUARY EVENT COSTS?

A. Yes. The investment community has expressed concern on how the public utilities commissions throughout the country will treat the extraordinary cost associated with the February Event. Generally speaking, their concerns are (1) will the utilities get full recovery of the cost, (2) when will recovery start, and (3) how long is the recovery period.

Q. HOW DOES THE RECOVERY PERIOD AND CARRYING COST IMPACT BHC's CREDIT METRICS?

A. If BHC recovers these costs over a longer timeframe, using a carrying cost of only long-term debt will put pressure on credit ratings and capital structure. Rating agencies review numerous financial metrics for a given entity. These credit metrics include assessment of the adequacy of the capital structure.

Credit ratings affect a company's ability to issue debt in a couple of ways. First, the lower the credit rating, the greater the risk: premium required from investors. Second, a lower rating limits the number of potential investors interested in a company's debt securities which reduces the market for the company's debt securities. Both of these circumstances tend to increase the overall cost of debt to a company.

Q. HAVE ANY UTILITIES RECEIVED CREDIT RATING DOWNGRADES AS A RESULT OF THE EXTRAORDINARY FEBRUARY EVENT COSTS?

A. Yes. Overhanging uncertainties regarding the timing and nature of recoupment for these extraordinary energy costs have impacted the credit rating for a number of regional gas utilities. Concerns over the timing and terms of gas cost recovery are magnified by the knowledge of regulator sensitivity to higher utility bills to customers.

Q. WHAT IS THE LONG-TERM IMPACT OF A BHC CREDIT RATING DOWNGRADE?

A. Financial integrity is critical to the ability of BHCG to satisfy its obligation to provide safe and reliable natural gas delivery services to its customers. The long-term impact of a credit rating downgrade is higher costs on short-term debt and future long-term debt issuances. A general rule of thumb is that a one notch downgrade will increase long-term debt rates by approximately 25 basis points and short-term debt by 5-10 basis points, depending on current market conditions. These additional costs would be passed on to customers because the Company's cost of service reflects its cost of debt.

B. SECURITIZATION

Q. WHAT IS SECURITIZATION?

A. Securitization is a type of financing that is secured by a specific revenue stream created by a financing order issued by a state utility commission that is designed to repay the principal and interest of the security as well as the administration and other costs associated with the securities. These securities rely solely on the cash flow stream generated by the underlying asset or pool of assets and not on the credit of the originating company. Securitization bonds have been issued by utilities in the past to recover stranded costs as a utility moves towards greener generation options and to recover costs due to hurricanes and wildfires.

Q. HAS BLACK HILLS CONSIDERED SECURITIZATION AS A METHOD OF FINANCING ITS EXTRAORDINARY COSTS RELATED TO THE FEBRUARY EVENT?

A. As required by Decision No. C21-0261, Black Hills analyzed the cost of an 84-month securitization. Black Hills does not recommend securitization as a means of financing the costs associated with the February Event.

Q. WHY HAS BLACK HILLS DECIDED NOT TO PURSUE FINANCING OF ITS EXTRAORDINARY COSTS THROUGH SECURITIZATION?

A. The extraordinary gas costs for the February Event is $72.6 million. This amount is less than the amount typically required to attract the interest of investors to put in the additional work required to review and invest in securitized bonds. This lower issuance size would increase the interest rate on the bonds compared to a larger securitization. Additionally, the upfront issuance costs and ongoing costs to administer the bonds for a securitization are more significant than for a standard senior, unsecured debt issuance (issued by BHCG's parent, BHC). Costs for securitization are mostly fixed or have minimums that must be met such that the costs for a smaller issuance can outweigh any benefits. Under these parameters, Black Hills' securitization package would likely be too small to obtain favorable terms.

Q. WHAT ADDITIONAL COSTS ARE INCURRED IN A SECURITIZATION BOND?

A. There are multiple costs that would be incurred in a securitization bond that are either higher than or in addition to a normal senior unsecured BHC bond issuance. For example, upfront issuance costs are higher to cover more legal fees due to the complex nature of the bonds, set-up fees related to the special purpose entity, and work incurred by the Commission for the financing order. Additionally, these bonds incur ongoing costs to administer, track, and rate for each year the bonds are outstanding. These on-going costs are paid by the special purpose entity and must be covered in the financing order.

Q. DID BLACK HILLS ESTIMATE WHAT THESE COST WOULD BE?

A. Yes, the Black Hills Treasury team estimated costs through discussions with banks, direct conversations with vendors (i.e., rating agencies), reviewing memorandums of previously issued securitization bonds by other utilities, and reviewing a filing made by Southern California Edison to estimate ongoing costs.

As requested by the Commission, Black Hills has prepared a scenario that would involve securitization of the February Event extraordinary costs. The cost of securitization is much higher than a normal senior unsecured bond. For this analysis, Black Hills estimates that securitization would cost approximately $10.8 million. Details of this analysis are shown in Attachment MJH-4 Securitization Analysis. As shown above in the bill impact analysis section, securitization would result in the highest overall cost to customers.

IX. HEDGING

Q. PLEASE EXPLAIN SOME OF THE COMPANY'S HEDGING TOOLS.

A. In addition to storage, as well as baseload contracts, the Company uses call option purchases as a financial hedging tool for its winter gas supply. A call option is a contract that gives the buyer the right, but not the obligation, to purchase an underlying asset (or, in the case of financial options, to purchase a referenced index) at a specified price. The given purchase price is referred to as the "strike price." The amount the call option purchaser pays for the contractual right mentioned above is known as the "premium." Call options are settled monthly at the beginning of the month, and the prices do not fluctuate within the month. Therefore, BHCG is not able to mitigate mid-month gas price spikes using these call options, as such this Commission approved hedging tool was not a viable option to mitigate the February Event cost.

Q. DOES BHCG SUBMIT ITS PROPOSED HEDGING PLAN FOR APPROVAL BY THE COMMISSION?

A. Yes. BHCG has a Commission approved hedging plan that covers July 1, 2020 through June 30, 2023. The hedging plan was approved by the Commission on December 20, 2019 by Decision No. C19-1028 in Proceeding No. 19A-0566G.

X. CUSTOMER COMMUNICATION

Q. DID BLACK HILLS PROACTIVELY COMMUNICATE WITH CUSTOMERS DURING THE FEBRUARY EVENT?

A. Yes. Black Hills actively worked to use and leverage available customer communication platforms to inform its customers of the need and importance of taking action to conserve their energy needs. The Company stood ready to arm its customers with practical information on how they could reduce their gas and electric consumption. Black Hills understood that there could be potential for customers to face high energy demands, and that those demands were coupled with a dramatic increase of natural gas prices. For that reason, we engaged with customers and took active measures to seek customer reductions in energy use. We are proud of our efforts to ensure customers received the information they needed to manage their bills and energy use.

Black Hills used a broad spectrum of communication channels to reach out to its customers. These channels include: (1) the customer call center; (2) energy efficiency content; (3) media and press statements; (4) customer emails; (5) Company website materials; and (6) comprehensive use of social media platforms, including Facebook, LinkedIn, Instagram, and Twitter. Black Hills worked to spread the message to customers of the importance of reducing their energy use. Black Hills' press releases resulted in coverage in local Colorado media.

The energy-saving messages that Black Hills communicated to customers involved reasonable steps to lower their energy use. We stressed the importance of lowering thermostats to a maximum of 68 degrees, as well as further reducing temperatures when customers are away from home or sleeping. We recommended customers hold off on doing chores, such as laundry or dishes, until the extreme cold abated. We also advocated for checking furnace filters to ensure they are clean and installed properly. Similarly, we communicated the need to ensure vents and heaters are free from obstructions or debris. And, we encouraged reducing hot water usage, including for showers, baths, as well as setting temperatures on water heaters to no more than 120 degrees. With our communications, we continued to stress how customers can receive assistance from Black Hills, including in obtaining bill payment assistance.

Q. HOW DID BLACK HILLS DETERMINE TO LAUNCH CONSERVATION COMMUNICATIONS WITH CUSTOMERS?

A. Black Hills launches conservation messaging tied with cold weather to customers based on the severity of weather events. For the February Event, the weather was abnormal and extreme, prompting the Company to begin its thorough communication efforts. The Company's communication team had discussions over the holiday weekend on communications needs and activating communication plans given the quickly evolving situation.

Q. DO YOU HAVE ATTACHMENTS PROVIDING THE FEBRUARY EVENT COMMUNICATION DETAILS?

A. Yes. With my testimony, I am providing Attachments MJH-5 and MJH-6. Attachment MJH-5 is a spreadsheet that contains all of the communications made by Black Hills with customers, both in Colorado and in our other service territories. This attachment does not include the media coverage of our media releases, which I discuss further below. Attachment MJH-6 provides illustrative examples of our communication efforts and it also includes a visualization of our communication approach over months leading up to the February Event. These attachments demonstrate the significant communication efforts Black Hills undertook.

Q. PLEASE DISCUSS NOTABLE COMMUNICATIONS PROVIDED IN ATTACHMENT MJH-5.

A. Through digital media between Feb. 11-26, Black Hills Energy posted 23 updates via social media channels that reached more than 72,000 customers with messaging focused on energy and conservation. Additionally, a direct-to customer email was sent on Feb. 15 with tips for keeping customers warm, while managing energy consumption. This email was sent to more than 600,000 customers across all BHC utilities and had an open rate of about 35 percent. Also notable, the Company engaged in media outreach beginning in February 11 with a reminder to clear snow from gas meters; a second press release was sent out to all Colorado media on February 15 with energy conservation reminders. Lastly, Black Hills' tips for conserving energy were highlighted in at least nine unique television stories and in local newspapers including (but not limited to) the *Pueblo Chieftain* and *Pagosa Daily Post*.

Q. BESIDES THE SPECIFIC FEBRUARY EVENT COMMUNICATIONS, HOW DOES BLACK HILLS SEEK TO INFORM ITS CUSTOMERS OF THE BENEFITS OF ENERGY EFFICIENCY?

A. Black Hills engages in customer education efforts throughout the year to prepare customers for changes in temperature, extreme weather, and tips/tools for reducing wasted energy. As an example, in October 2020, the Company used bill inserts to highlight low- and no-cost weatherization efforts that help conserve energy during the coldest months of the year.

The Company's website also includes energy-saving tips and information. Moreover, the Company works year-round to engage with customers on program offerings to reduce consumption and demand through energy efficiency programs. Our marketing platforms ensure our customers understand the utility resources they have available to obtain cost-effective solutions to energy challenges. The Company informs its customers year-round to assist with abnormal situations such as the February Event.

Q. WHAT IS THE ESTIMATED IMPACT THE CUSTOMER COMMUNICATIONS HAD ON CUSTOMER BEHAVIOR?

A. The Company is not able to quantify an actual amount of energy reduction associated with its extensive communications. By this, I am not inferring that the Company's messaging failed to trigger customer conservation efforts. Rather, the Company does not have the ability to quantify with any statistical accuracy the energy reduction from customer communications. This information is not quantifiable with accuracy given the multitude of assumptions and speculations necessary with such a request. Even more, no particular amount of reductions would stem directly from communication efforts, as there are nearly innumerable reasons for why a customer or aggregated levels of customers may have reduced energy consumption. Given these complexities and the lack of potential accurate information on energy reductions from customers directly related to the Company's communications, the Company is not providing quantified estimates.

Moreover, as Company witness Mr. Bauer explains, the Company was required to purchase gas supply on February 12 for the days of February 13-16. The Company therefore had the need to purchase the gas supply, regardless of how customers reacted to the Company's conservation messaging.

Nevertheless, as provided in Attachment MJH-6, the Company has provided measurable customer engagement metrics that many of its communication efforts had with customers. This information provides that the Company's communication efforts did in fact reach customers. It is therefore reasonable to assume that the Company's communication efforts impacted customer energy use.

XI. MANAGEMENT REVIEW

Q. PLEASE GENERALLY DISCUSS THE COMPANY'S MANAGEMENT REVIEW PROCESS FOR GAS SUPPLY.

A. The management review process is a continuous process, which begins with preparations for the filing of the annual gas supply plan (Gas Purchase Plan). From that point and before each gas flow month, gas supply management and purchase discussions occur, considering more current analysis of weather, load, storage activity, upstream pipeline operational conditions, and price. This pre-month preparation and purchase activity is summarized in a monthly setup sheet, which is undertaken and reviewed by the Senior Manager of Gas Supply Services and the Vice President of Gas Supply and Transportation Services.

As described by Company witness Mr. Bauer, prior to each gas day, the Senior Manager of Gas Supply Services reviews updated weather forecasts, load forecasts, and pipeline operational conditions, to make gas supply management decisions, which may include gas purchases and modifications to planned storage activity. Contracted storage is managed within the contractual rights of the service and limitations. Contracted storage is also factored into the gas supply management decision-making process relative to pipeline operational conditions, weather forecast, and load volatility. This process ensures supply reliability and pipeline penalty mitigation.

Q. PLEASE DESCRIBE THE COMPANY'S TRANSACTIONAL POLICIES FOR PROCURING NATURAL GAS.

A. All employees of Black Hills are bound to act and perform their duties in line with Company policies and procedures. Activities performed within the Gas Supply and Transportation Services teams, and specifically those related to transactional activities, are governed by the Company's applicable risk policy and contract policy. In its policies, the transactional authority levels are identified for procurement of natural gas for customers and for contracting of pipeline services to ensure reliable delivery to customers when natural gas is needed. In typical situations, employees at the manager level of Black Hills have authority to transact for natural gas, as the prices and volumes are within authorized levels for these positions. If natural prices or volumes exceed the manager's transactional authority levels, the Director and Vice President of Gas Supply and Transportation Services may grant the manager additional purchasing authority. The Gas Supply and Transportation Services team has these flexible policies in place to ensure that customer supply will be obtained and reliability ensured.

Q. PLEASE MORE SPECIFICALLY DISCUSS THE MANAGEMENT REVIEW PROCESS FOR GAS SUPPLY DURING THE FEBRUARY EVENT.

A. Management within BHC was aware of the forecasted cold weather that might occur leading up to the President's Day Weekend. At this early juncture, there was no indication that gas supply prices would dramatically increase in Colorado to the prices experienced. Black Hills' Colorado systems are well suited and accustomed to cold weather events. If not for the impacts to the natural gas market that are outside of Black Hills' control, the February Event would have been a typical cold weather instance on the Black Hills' system.

Moving to the natural gas price spike, as discussed by Mr. Bauer, the Company generally observed elevated natural gas prices at approximately 7:30 a.m. on Friday, February 12, 2021, for the trading period effective February 13-16, 2021. During the trading day, the Company's gas supply managers procured gas as prudently as possible, and the Company did not impede or delay in any fashion the Company's gas supply managers from transacting prudently.

In response to the increased prices, communication of the price levels were elevated to the Vice President of Gas Supply and Transportation Services, members of Company's Risk and Treasury departments, the Vice President of Operations for BHC utility (including Colorado), along with the Vice President of Natural Gas Utilities. Collaborative communication by these Company groups was imperative to advise on gas price levels and to prepare for any potential supplier credit assurance requests. The Company proactively worked to ensure it had sufficient credit assurances in place such that there would be no impediment to the Company's gas purchases.

Additionally, on February 12, in anticipation that transaction authority levels for the Senior Manager of Gas Supply Services might approach or exceed their financial threshold limits, the Vice President of Gas Supply Services granted transactional authority to the Senior Managers of Gas Supply Services. At this time, the Company had already transacted on a volume basis for its gas supply. However, because the prices were pegged to the market index and it became clear that prices would exceed the transaction authority limits, it was important to ensure the Senior Managers had transaction authority on a notational basis to prevent impediments to the gas purchases. Company witness Mr. Bauer discusses these gas supply transactions.

Based on the confidence that our systems could perform safely and reliably in the face of the winter event, and the confidence of supply availability and reliability, no mandatory customer curtailment action was taken. Black Hills' efforts to secure supply during this event ensured it could safely and reliably serve customer needs.

Q. WHAT OTHER INFORMATION IS PERTINENT WITH REGARDS TO BHCG's CORPORATE PARENT, BLACK HILLS CORPORATION?

A. The February Event demonstrates that BHC took the necessary actions to ensure there would be no issues for the Gas Supply team in transacting for prudent gas supply. Because reliability of service is of the upmost importance, BHC took rapid actions to make sure the necessary gas supplies were procured. BHC also ensured that the operation teams were fully informed and ready for the abnormally cold weather event. BHC made sure customers were made aware of conservation efforts, as discussed above. Further, and as also described above, BHC acquired debt necessary to ensure the continued financial health of the Company, promoting cost stability for customers. The immense work undertaken by BHC employees made sure proper coordination took place among the various Company teams, streamlined processes to avoid impacting the gas supply transactions, and ensured continued service to customers.

XII. COMMISSION'S REVIEW OF GAS COSTS

Q. WHAT IS THE TYPICAL PROCESS FOR THE COMMISSION REVIEW OF THE COMPANY'S GAS COSTS?

A. The Commission's rules provide the process for review of the Company's gas costs, which the Commission undertakes through the Gas Purchase Report ("GPR"). Pursuant to Rule 4607(a), the GPR is filed at the same time as the Company's annual GCA application (around October 15). After the submittal, the Commission may initiate a prudence review hearing. *See* Rule 4607(b). The prudence review hearing may result in tariff/rate changes.

Q. FOR THE FEBRUARY EVENT GAS COST, IS THERE A DIFFERENT COMMISSION REVIEW PROCESS FOR THE GAS COST?

A. Yes, as previously explained, the Commission in Decision No. C21-0261 directed the Company to separate the February Event extraordinary gas costs from the GCA and seek recovery of those in this separate application.

Q. WHAT IS THE COMMISSION'S REVIEW STANDARD FOR THE COMPANY'S RECOVERY OF GAS COSTS?

A. Commission Rule 4607(c) provides the standard of review for GCA recovery. It provides the following:

> For purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action).

Commission Rule 4607(d) also provides the burden of proof for the prudency review hearing of GCA costs as the following:

> If the Commission elects to hold a hearing, the utility shall have the burden of proof and the burden of going forward to establish the reasonableness of

> actual gas commodity and demand costs paid by the utility, actual costs incurred in volatility management, and actual upstream service costs of any nature incurred during the review period.

Q. ARE YOU AWARE OF ANY COMMISSION DECISIONS THAT FURTHER DISCUSS PRUDENCY REVIEW?

A. Yes. In a recent decision, the presiding Administrative Law Judge ("ALJ") issued Decision No. R20-0144 on Public Service Company of Colorado's ("PSCo") updating of its Electric Commodity Adjustment ("ECA"). In that decision, the ALJ found that the definition of the word "prudence" is not contained within the Commission's rules or Colorado statutes.[16] The ALJ also determined that the ECA is analogous to the GCA.[17] The ALJ thus adopted the prudency review standard used in GCA proceedings, which I previously explained is contained in Rule 4607(c).[18]

The ALJ then determined that PSCo "bears the ultimate burden of proof," but utility expenditures have a rebuttable presumption of prudence and thus, any party contesting such costs bears the burden of making a *primie facie* case of imprudence."[19] Relating these standards to the case, the ALJ explained the following:

> The instant proceeding is an application. The burden of proof and the burden of going forward are on the applicant in any application.
>
> The initial burden is met by the applicant with the filing of testimony and exhibits in support of the application. After this filing, the burden of going forward, not the burden of proof, shifts to the intervenor to contest the prudency of any or all of the actions of the applicant. An intervenor may not present a blanket objection to the prudency of fuel, purchased energy,

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[16] Proceeding No. 19A-0425E, Decision No. R20-0144 at ¶ 24.
[17] *Id.* at ¶ 25.
[18] Id. at ¶ 26.
[19] *Id.* at ¶ 27 ("*See* Commission Decision No. C12-0159 in Proceeding No. 11A-325E issued February 14, 2012. In Decision No. C12-0159, the Commission found that expenditures to install emission controls at the Pawnee unit would be given a "general presumption of prudence" when the issue of the prudence of those expenditures was taken up in a future rate case. The Commission also stated that the utility carries the burden of proof and that the general presumption of prudence is rebuttable.").

> and purchased wheeling costs. Rather, an intervenor must present evidence identifying the specific actions that were not prudent. If the evidence is sufficient to bring into question the prudence of actions taken or not taken by the utility, the burden of going forward then shifts back to the utility to show that the questioned action or lack of action was prudent.
>
> Here, the initial burdens of Public Service were met by the filing of testimony and exhibits in support of the Application. To meet the burden of going forward, the OCC must provide sufficient specific evidence that the expenditures of Public Service were not prudent.[20]

Q. WHY HAVE YOU DISCUSSED THIS DECISION?

A. I am not an attorney. I was also not involved in the proceeding in which the decision was decided. Nevertheless, I have been advised and it is my general understanding that the prudency burdens discussed by the ALJ are the Commission's adopted positions on these matters, and they therefore may be instructive for this proceeding.

Q. IS THE COMMISSION'S REVIEW STANDARD DIFFERENT FOR THE FEBRUARY EVENT GAS COST?

A. The Company understands that the February Event entailed an abnormal situation and there were extraordinary gas costs. Nevertheless, the same prudency review standards appear applicable to this proceeding. In addition, the Company's actions were prudent, as provided in the testimonies supporting this application. The Company followed its Commission-approved gas purchasing and hedging plans. The Company's efforts saved customers approximately $67.8 million. It was diligent and acted reasonably in procuring gas to serve customer needs. It communicated with its customers about the February Event. And, most importantly, its actions ensured safe and reliable service during an extreme weather and gas event.

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[20] *Id.* at ¶¶ 27-30.

XIII. WAIVERS AND VARIANCES

Q. IS THE COMPANY REQUESTING ANY WAIVERS AND VARIANCES?

A. Yes. I have explained that the Commission's Decision No. C21-0261 directed the Company to file an application to address the recovery of the extraordinarily high expenses incurred for its utility operations in response to the February Event.[21] This Commission directive requires Black Hills to seek to recover the costs of the February Event outside of the Commission's current rules governing the GCA, as well as outside of the Company's GCA tariff. Consistent with the Commission's directives, the Company has proposed new cost recovery treatment of the February Event costs through a new rate adjustment. The Company respectfully requests the Commission grant waivers and variances for the Company to establish the new rate adjustment and recover the February Event costs outside of the GCA rules and tariff, if the Commission deems such waivers/variances necessary. There is good cause for any such waivers/variances because the Commission in Decision No. C21-0261 instructed Black Hills to propose recovering the February Event costs outside of the GCA rules and tariff.

XIV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

[21] Proceeding No. 21M-0130EG Decision No. C21-0261 at Ordering ¶ 3.

Appendix A

Statement of Qualifications

Michael J. Harrington

Mr. Harrington graduated from the University of North Texas in 2003 with a Bachelor of Business Administration with a concentration in Economics. In 2007, Mr. Harrington received a Master's of Business Administration from Texas Woman's University. In addition, Mr. Harrington has attended several utility industry training seminars including utility rate making, regulatory finance, and utility tax.

In 2004, Mr. Harrington began his career as a Property Tax Appraiser for the Tarrant County Appraisal District in Fort Worth Texas. He was responsible for appraising commercial and business personal property for property tax purposes. He negotiated settlements of disputed property values and testified before the Appraisal Review Board.

In 2008, Mr. Harrington was employed by Atmos Energy as a Sr. Rate Analyst. In that role he prepared various regulatory filings including cost of service studies, class cost of service studies, annual earnings reports, gas infrastructure replacement filings, and other various reports for several state regulatory commissions. He also assisted in preparing, writing, and analyzing expert testimony and he represented the company in meetings with state regulators.

In 2010, Mr. Harrington was employed by Xcel Energy as a Principal Rate Analyst. In that role he was responsible for managing the FERC Jurisdictional Formula Rate Templates for Public Service Company of Colorado and Northern States Power - Wisconsin. Mr. Harrington was responsible for preparing other various regulatory filings before the FERC. In addition, Mr. Harrington was responsible for preparing the cost of service studies for Xcel Energy's New

Mexico jurisdiction. Mr. Harrington represented the Company in numerous presentations, settlement negotiations, and in other meetings with state and federal regulators.

In 2014, Mr. Harrington was employed by SourceGas Utility Holdings, LLC as Manager, Rates and Regulatory. In that role he had overall responsibility for the Company's regulatory filings and tariff management before the Colorado Public Utilities Commission. Mr. Harrington was responsible for implementing the regulatory strategy in Colorado. He represented the Company in numerous presentations, settlement negotiations, and sponsored expert testimony before the Colorado Public Utilities Commission.

In February 2016, Black Hills Utility Holdings, Inc. ("BHUH") acquired SourceGas Utility Holdings and, shortly thereafter, Mr. Harrington assumed the role of Manager - Regulatory for BHUH. In this position, Mr. Harrington was responsible for managing various regulatory filings for Black Hills Colorado Electric, LLC. He represented the Company in stakeholder/regulatory presentations, settlement negotiations, and sponsored expert testimony before the Colorado Public Utilities Commission.

In December 2019, Mr. Harrington assumed to the role of Sr. Manager of Regulatory & Finance. In this position, Mr. Harrington continued his responsibility for managing various regulatory filings for Black Hills Colorado Electric, LLC. In addition, he was responsible for managing the development, analysis, and interpretation of financial forecasts, including budgets and strategic plans for Black Hills Colorado Electric, LLC.

In November 2020, Mr. Harrington was promoted to Director of Regulatory & Finance. In this position, Mr. Harrington is responsible for managing all aspects of the regulatory and financial process for Black Hills natural gas local distribution company, intra-state natural gas pipeline, and its electric utility in Colorado.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A – _____G

IN THE MATTER OF THE VERIFIED APPLICATION OF BLACK HILLS COLORADO GAS, INC. FOR APPROVAL TO RECOVER GAS COSTS ASSOCIATED WITH THE FEBRUARY EXTREME COLD WEATHER EVENT

State of Colorado	)	Affidavit Adopting
	) SS.	Direct Testimony and Attachments
City and County of Denver	)	

Michael J. Harrington being duly sworn, states that he is the Michael J. Harrington whose Direct Testimony and Attachments in the above-captioned proceeding accompany this Affidavit.

Michael J. Harrington further states that such Direct Testimony is a true and accurate statement of his answers to the questions contained therein, and that he does adopt those answers as his sworn Testimony in this proceeding. Michael J. Harrington further states that such Attachments that accompany his Direct Testimony are true and accurate.

Mike Harrington

Michael J. Harrington

Subscribed and sworn to before me this 17th day of May, 2021.

Elaine D. Hegler

Notary Public

ELAINE D HEGLER
Notary Public
State of Colorado
Notary ID # 19984031852
My Commission Expires 11-17-2022