Before the Office of Administrative Hearings
600 North Robert Steet
Saint Paul, Minnesota 55101

For the Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
Saint Paul, Minnesota 55101

IN THE MATTER OF THE PETITIONS FOR RECOVERY OF CERTAIN GAS COSTS	OAH Docket No. 71-2500-37763
IN THE MATTER OF THE PETITION OF CENTERPOINT ENERGY FOR APPROVAL OF A RECOVERY PROCESS FOR COST IMPACTS DUE TO FEBRUARY EXTREME GAS MARKET CONDITIONS	MPUC Docket No. G008/M-21-138
IN THE MATTER OF THE PETITION BY GREAT PLAINS NATURAL GAS CO., A DIVISION OF MONTANA-DAKOTA UTILITIES CO., FOR APPROVAL OF RULE VARIANCES TO RECOVER HIGH NATURAL GAS COSTS FROM FEBRUARY 2021	MPUC Docket No. G004/M-21-235
IN THE MATTER OF A PETITION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY TO RECOVER FEBRUARY 2021 NATURAL GAS COSTS	MPUC Docket No. G002/CI-21-610
IN THE MATTER OF THE PETITION OF MINNESOTA ENERGY RESOURCES CORPORATION FOR APPROVAL OF A RECOVERY PROCESS FOR COST IMPACTS DUE TO FEBRUARY EXTREME GAS MARKET CONDITIONS	MPUC Docket No. G011/CI-21-611

PREFILED DIRECT TESTIMONY OF RONALD NELSON ON BEHALF OF THE CITIZENS UTILITY BOARD OF MINNESOTA

December 22, 2021

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Exhibit___(REN-D), Schedule 1	Resume

PREFILED DIRECT TESTIMONY OF

RONALD NELSON

ON BEHALF OF THE CITIZENS UTILITY BOARD OF MINNESOTA

I. Introduction and Qualifications

Q1. Please state your name and position.

A1. My name is Ron Nelson. I am a Senior Director at Strategen Consulting located at 2150 Allston Way Suite 400, Berkeley, California 94704.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of the Citizens Utility Board of Minnesota ("CUB").

Q3. Please describe your formal education and professional experience.

A3. Currently, I am a Senior Director at Strategen Consulting. During my time at Strategen, I have worked with numerous consumer advocates, non-governmental organizations, state commissions, and utilities on issues related to cost-of-service modeling, rate design, grid modernization, and performance-based regulation on utility cases throughout the country.

Before joining Strategen in early 2018, I worked for the Minnesota Attorney General's Office for over 4 years where I worked on cost of service, rate design, renewable energy program design, performance-based regulation, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of

Science from Colorado State University in Agriculture and Resource Economics, and a Bachelor of Arts in Environmental Economics from Western Washington University, where I minored in Mathematics. My resume is attached as Exhibit___(REN-D), Schedule 1.

Q4. Have you previously testified before the Minnesota Public Utilities Commission?

A4. Yes, I have testified in Minnesota in nine electric and natural gas rate case proceedings on issues related to cost-of-service modeling, revenue apportionment, rate design, renewable program development, tariff analysis, fuel clause structure, multi-year rate plans, performance metrics, performance incentive mechanisms, decoupling, and the utility business model.

Q5. Have you testified or participated in regulatory proceeding before other state commissions?

A5. Yes. In total, I have testified in over 20 proceedings in Minnesota, Pennsylvania, Oklahoma, Illinois, Utah, New Hampshire, Ohio, and Vermont. The issues covered in these proceedings include marginal and embedded cost-of-service studies, revenue apportionment, rate design, renewable program design, fuel clause adjustments, formula rates, decoupling, performance-based regulation, multi-year rate plans, performance metrics, distributed energy resource (DER) interconnection, DER compensation, DER integration, and smart inverter specifications.

I have also assisted with testimonies and regulatory analysis in Hawaii, Washington D.C., Maryland, Massachusetts, Connecticut, North Carolina, Kentucky, and the Federal Energy Regulatory Commission. For example, I am acting as the Hawaii Public Utilities Commission's advanced rate design expert in Docket No. 2019-0323, and co-leading the consulting effort to implement the recently passed PBR legislature with the Public Utility Regulation Authority. Issues covered in other engagements include electric vehicle rate design and infrastructure, wholesale electric market tariff design, cost-benefit analysis, community-based solar programs, rate design, cost and rate unbundling, decarbonization strategy, integrated resource planning, energy storage integration, and DER interconnection.

Q6. Do you have additional relevant experience?

A6. Yes. While at the Minnesota Attorney General's Office, I worked on numerous natural gas dockets including Gas Utility Infrastructure Cost (GUIC) Rider proceedings. I also assisted internally with the prudency review of Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns.[1] Finally, I note that much of my work on performance-based regulation is concerned with creating regulatory frameworks that fairly balance risk between ratepayers and the utility. Balancing risk fairly is important because it can better align utility incentives, and therefore decision making, to the benefit of ratepayers.

[1] Docket No. E-002/CI-13-754

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to provide a summary of Strategen's analysis and recommendations, provide Strategen's policy-based analysis on the February 13-17 Price Spike Event ("the Event"), and to introduce CUB's additional witness, Bradley Cebulko.

Q8. Please explain the scope and structure of CUB's testimonies in this proceeding.

A8. CUB has two witnesses that analyze the prudency of the decision making of CenterPoint Energy ("CenterPoint"), Minnesota Energy Resources Corporation (MERC), and Xcel Energy ("Xcel") (together "Companies") before and during the Event.

Witness Cebulko is a Senior Consultant at Strategen and has extensive experience in natural gas integrated resource planning and other regulatory proceedings. Witness Cebulko conducts Strategen's technical analysis of the Event and provides disallowance recommendations based on the results of said analysis. My testimony summarizes Strategen's recommendations and provides policy analysis related to the Event.

Strategen is not providing analysis or opinion on the prudency of Great Plains Natural Gas Co. and takes no position in regard to Great Plains in direct testimony.

Q9. How is your testimony organized?

A9. My testimony is divided into several sections. Section II provides the summary of CUB's analysis and recommendations. Section III described the Annual Automatic Adjustment (AAA) proceeding and Purchased Gas Adjustment (PGA) mechanism and the economic incentives created by the PGA. Section IV explains the prudency standard and provides policy analysis related to the prudency review. Section V outlines our recommendation to better ensure that ratepayers are protected from similar price spike events in the future. In Section IV I conclude my testimony.

II. Summary of Strategen's Prudency Analysis and Disallowance Recommendations

Q10. Please summarize how Strategen approached determining the prudence of the three utilities.

A10. We reviewed the utilities' actions with an understanding that the key issues are inter-dependent and based on what the utility knew or reasonably should have known at the time that it made its decisions. We then answered the question of whether the utility acted with "the care that a reasonable person would exercise under the same circumstances at the time the decision was made."[2] Because the burden of proof is on the utility to demonstrate that costs were prudently incurred, we have considered the utilities' transparency in explaining their decision-making prior to and during the Event. To the extent that utilities do not provide the

[2] Administrative Law Judge Allen E. Giles, "Corrections to Report," Docket No. E-001/GR-91-605 Report Issued in the Matter of the Application of Interstate Power Company to Increase its Rates for Electric Service in the State of Minnesota, *Minnesota Public Utilities Commission* (April 17, 1992).

information needed to demonstrate that their decisions were prudent when compared with potential alternatives, Minnesota law requires ruling in favor of the ratepayer.[3]

We structured our direct testimonies into a policy and technical response to the information provided by the Companies in their direct testimonies as well as discovery responses.

Q11. What are Strategen's disallowance recommendations for each utility?

A11. Strategen recommends that the Commission find disallowances of $130.4 million for CenterPoint, $22.1 million for MERC, and $69 million for Xcel. My recommendation is built off Witness Cebulko's technical analysis. For each utility, Witness Cebulko created multiple, reasonable scenarios that estimates the savings to customers if each utility took a different set of actions. I reviewed Witness Cebulko's analysis and propose specific disallowances for each utility that 1) ensure our recommendations are based off consistent standards across the utilities and 2) consider the reasonableness of the total proposed disallowance based on the scenarios.

Table 1. Strategen's Disallowance Recommendations

Issue	**CenterPoint**	**MERC**	**Xcel**
Curtailment	$73,602,994	$4,083,076	$1,585,125
Load forecasting and storage optimization	None	$18,028,508	$9,734,465
Peaking optimization	$56,809,146	None	$57,895,657

[3] Minnesota Stat. § 216B.03

Total	**$130,412,140**	**$22,111,585**	**$69,215,247**

Q12. Please summarize the key conclusions reached with regard to whether CenterPoint acted prudently prior, during, and after the February 13-17 Price Spike Event (Event).

A12. Although CenterPoint was aware that spot prices had reached significantly escalated levels – the 98th percentile from the previous decade, or $15/Dth – at the time of its procurement decisions on February 12 and aware that prices had reached unprecedented levels at the time of its procurement decisions on February 16, CenterPoint chose not to maximize curtailments or use its available LNG and propane peaking resources to mitigate costs to customers during the Event. Witness Cebulko developed a range of disallowances between $29.6 million and $196 million based on several scenarios that are both plausible and reasonable.[4] After reviewing Witness Cebulko's analysis and range of disallowances, I am proposing the Commission disallow $130.4 million of costs from CenterPoint. My disallowance recommendation is based on my conclusion that 1) CenterPoint's actions were imprudent over the entire five days of the Event and 2) of the two peaking facilities dispatch scenarios Witness Cebulko developed, adopting the more conservative scenario that incorporates modest dispatch of both LNG and propane facilities better balances the public interest.

[4] Cebulko Direct, p.8-9.

Q13. Please summarize the key conclusions reached with regard to whether MERC acted prudently prior, during, and after the Event.

A13. MERC was aware of price volatility in the spot market and MERC substantially over-projected load for MERC Northern Natural Gas (NNG) on the key planning dates of February 14 and 17. The scale of MERC's over-projections on these key dates – particularly on February 17 – appear to be anomalies for the Company and were not justified within MERC's direct testimony. As a result of MERC's overly conservative forecasting for MERC NNG, the Company was unable to maximize storage to the extent that would have been possible with less over-supply. In addition, MERC did not request any curtailments during the Event.

CUB Witness Cebulko developed a range of disallowances between $9.3 million and $22.1 million.[5] After reviewing Witness Cebulko's analysis and range of disallowances, I am proposing the Commission disallow $22.1 million of costs from MERC. MERC's actions were imprudent on all five days of the Event, the Company should have called at least 50 percent of its curtailments throughout the Event, and it should have been capable of forecasting more accurately during the Event.

Q14. Please summarize the key conclusions reached with regard to whether Xcel Energy acted prudently prior, during, and after the Event.

A14. Xcel chose to base its supply planning on forecasts that included non-firm customers who would be curtailed during the Event and did not justify this

[5] Cebulko Direct, p. 9-10.

approach in direct testimony. Thus, Xcel over-procured expensive spot purchases during the Event, and was unable to maximize storage as a result. Although Xcel maximized curtailments over February 13-16, the utility began to release customers from curtailments on February 17 – a decision that could have been avoided with better planning and less over-procurement. Xcel also did not utilize its peaking plants, as these resources were unavailable during the Event. Xcel did not provide sufficient evidence that it had been properly maintaining the LNG facility, nor does the Company provide sufficient justification as to why it voluntarily made the propane facilities unavailable in January 2021.

CUB Witness Cebulko developed a range of disallowances between $5.6 and $126.7 million.[6] After reviewing Witness Cebulko's analysis and range of disallowances, I am proposing the Commission disallow the cost recovery of $69 million for Xcel. To inform my disallowance recommendation, first I conclude that Xcel's actions were imprudent on all five days of the Event. Second, Xcel's forecasts were unreasonable during the Event. Finally, I recommend including a disallowance due to the unavailability of Xcel's LNG and propane peak shaving facilities. The disallowance I recommend was determined using a similar scenario as for CenterPoint, which relied upon a modest economic dispatch from both Xcel's LNG and propane peak shaving facilities.

Q15. What are the primary issues that influenced the determination of prudency across the three utilities?

[6] Cebulko Direct, p.10-11.

A15. At a high level, the case can be distilled into two primary issues. First, the Companies did not reasonably balance cost and risk for ratepayers. For example, the Companies did not economically dispatch interruptible load, LNG and propane peak shaving facilities, and, to a lesser extent, storage resources in a reasonable way. The Companies failed to demonstrate that there were legal or operational barriers to fully curtailing interruptible customers and reasonably utilizing peaking facilities to lower the costs incurred by ratepayers.

Second, the Companies failed to provide sufficient evidence in their direct testimonies to demonstrate their decision making was prudent prior to and during the Event. At the time that the Companies were developing their supply plans for the long weekend on February 11, the Companies had full knowledge that natural gas prices were nearly the highest seen in ten years ($15/Dth), that the pipelines were stressed, and that the worst of the storm had yet to hit. On February 16, when the Companies created supply plans for February 17, they were amidst an unprecedented price spike and knew the extent of the storm's damage. CUB Witness Cebulko and I provide examples of the Companies' failures to provide sufficient support for their decision making throughout our testimonies. However, key issues include the interconnection of decisions made, such as load forecasts and storage utilization, operational utilization of LNG and propane peak shaving facilities, and important considerations related to interruptible load. Simply stated, the Companies did not meet their burden of proof to demonstrate all of the extraordinary costs they now seek to recover were prudently incurred.

III. Purchased Gas Adjustment Mechanism

Q16. What is the purpose of this section of your testimony?

A16. The purpose of this section is to outline what an annual automatic adjustment (AAA) is and the associated purchased gas adjustment (PGA) mechanism, discuss the economic incentive created by fuel adjustment mechanisms, and explain why the current incentive structure of the purchase gas adjustments creates a shifting of risk away from the utilities and onto ratepayers when compared to other forms of cost recovery mechanisms.

Q17. What is a fuel adjustment mechanism?

A17. Electric and natural gas utilities use adjustment mechanisms to recover variations in specific costs outside of the traditional rate case process. In Minnesota, there are fuel clause adjustments (FCA) for electric utilities and purchased gas adjustments (PGA) for natural gas utilities. These adjustments are often called automatic adjustments, because a utility generally implements these rate changes in advance of Commission approval. For the purposes of my testimony, the term adjustment mechanism will be used to refer to FCA and PGA mechanisms.

Q18. Please explain the current PGA utilized by the Minnesota natural gas utilities.

A18. The details of the PGA are the same for each of Minnesota's natural gas utilities. The natural gas utilities are allowed to vary their purchased gas costs automatically on a month-to-month basis and pass through 100% of natural gas cost variation to customers.

Additionally, every year the Commission reviews the automatic adjustment of charges reported in the natural gas utilities' AAA reports and the natural gas utilities' annual true-up filing.

Q19. What are some purposes of the PGA?

A19. Some of the purposes of an adjustment mechanism are to 1) reduce regulatory lag for utilities and 2) conserve regulatory and utility resources. Fuel and purchased power costs can fluctuate significantly between rate cases, so building these costs into non-adjustable rates can cause significant, recurring mismatches between expenses and revenues. This can also strain utility and regulatory resources by forcing frequent rate cases and earnings investigations to address changes in the cost of fuel and purchased power. For these reasons, PGAs are used to reduce the lag that could otherwise be created, for utilities and ratepayers, through rate cases by allowing true ups of costs and revenues outside of a rate case.

Q20. Why is the PGA important to this proceeding?

A20. The PGA is important because it is, along with the AAA, the regulatory mechanism that permits natural gas utilities to pass fuel costs on to ratepayers. Therefore, its structure, and the incentives created by its structure, are important to understanding the economic incentives that influence utility decision making. Under traditional regulation, utilities are incented to minimize costs between rate cases, because they cannot increase rates. The PGA is an exception. The PGA allows utilities to change the rate charged to customers monthly and pass through these costs without a rate case. Because the PGA allows the utility to pass through costs to ratepayers between rate cases, it reduces the utility's incentive to control and manage fuel costs. The reduced incentive to control and manage fuel costs impacts utility decision making. The PGA, and the incentives it creates, represents an important component of the regulatory framework that needs to be understood and considered in this prudence review.

Q21. Are the purposes of adjustment mechanisms for electric and gas utilities inherently different?

A21. While adjustment mechanisms for electric and gas utilities are often referred to by different names - a fuel adjustment clause and a purchased gas adjustment clause, respectively - the purposes they serve within the regulatory framework are similar.[7]

Q22. What are some shortcomings of adjustment mechanisms?

A22. Adjustment mechanisms can provide a disincentive for efficient management of fuel and natural gas costs because they largely remove the risk of higher fuel costs and variability from the utility and place it with ratepayers. Because natural gas utility fuel costs are pass-throughs to customers, and the utility can adjust its baseline and recovery on a relatively frequent basis, the structure of the

[7] Obviously, there are differences in the planning, procurement, and markets, among other differences, between natural gas and electric utilities, and therefore the costs that are passed through the mechanism, but the purpose served by the adjustment mechanisms are similar.

mechanism provides a relatively weaker incentive to the utility to proactively engage in economic dispatch of available resources or otherwise avoid unnecessary costs that the utility anticipates will be recoverable from their customers. The mechanism incentivizes the utility to minimize risk and ensure quick cost recovery. Said another way, adjustment mechanisms incent a least-risk path for the utility, which is unlikely to result in a reasonable balance of risk and cost for the ratepayer.

Q23. Have regulators created approaches to addressing the perverse economic incentives created by adjustment mechanisms?

A23. Yes. Regulators have modified adjustment mechanisms to address perverse economic incentives.[8] In some states, these adjustment mechanisms include sharing bands and dead bands.[9] A dead band provides bounds within which cost variations are absorbed by the utility, whether positive or negative. A sharing band provides bounds within which customers and the utility will share any variance in costs at a specified sharing split. Sharing bands can be symmetrical or asymmetrical. Some states have also implemented sharing splits between utilities and customers.[10] A sharing split specifies the division of certain costs between the

[8] Fuel and Purchased Power Survey Results, Wyoming Office of Consumer Advocate (September 23, 2015) at https://pubs.naruc.org/pub/4AA28D50-2354-D714-5149-B773EFC3EFEF and A Hard Look at Incentive Mechanisms for Natural Gas Procurement, The National Regulatory Research Institute (November 2006) at https://pubs.naruc.org/pub/FA864044-E284-E4FD-A64D-DC5E0CED7D02
[9] Final Decision and Order No. 35545, Hawaii PUC Docket No. 2016-0382 (June 22, 2018) and Order No. 99-272, Oregon PUC Docket No. UM 903 (April 19,1999).
[10] Settlement Stipulation, Washington PUC Docket No. UE-011595, and Order No. 99-272, Oregon PUC Docket No. UM 903 (April 19,1999), and Order No. 30715, Idaho PUC Case No. IPC-E-08-19 (January 9,2009).

utility and customers. Sharing splits have ranged from 80-20 to 98-2 (customer-utility).[11]

The modification of adjustment mechanisms via addition of dead bands, sharing bands, and sharing splits provides an incentive for utilities to balance cost and risk by establishing a level of risk sharing between the utility and customers rather than passing on all cost variations to customers.

Q24. Is there an example of the perverse economic incentive created by the PGA being on display prior or during the Event?

A24. Yes. After procuring historically expensive gas over the four-day weekend, a CenterPoint employee stated, "We experienced significant price increases today as we locked in our marginal natural gas supply for the next four days. … this is fully recoverable as a pass through cost."[12] This is a clear example of how utilities do not bear the full risk of fuel cost increases and shift risk to ratepayers dismissively.

Q25. Have Minnesota stakeholders considered an alternative FCA to better address the perverse incentives to electric utilities?

[11] *Ibid.*
[12] *See* CenterPoint Energy's public response to OAG IR 117, Attachment 5 in Docket No. 21-135. Available here: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B1048817A-0000-CB97-B67A-B4DA701FE8EB%7D&documentTitle=20217-175866-05

A25. Yes. The Commission adopted changes to the FCA in 2017, after years of debate on the topic. [13] The changes adopted by the Commission were intended to address perverse economic incentives that were present within the FCA.

Q26. Has an alternative PGA been considered in Minnesota to better address gas utility incentives?

A26. Not that I am aware of. Similar economic incentive issues are present within the PGA but have not been addressed. Therefore, the perverse incentive to minimize risk to the utility without due consideration of the costs to customers remains with the existing structure of the PGA. The presence of these economic incentives likely influences fuel-related utility decision-making to the detriment of ratepayers.

IV. Prudency Standard

Q27. What is the purpose of this section of your testimony?

A27. This section focuses on defining prudence, particularly on how the prudence standard has been applied in Minnesota, in order to form a basis for assessing prudence in this proceeding and to set parameters on which information is and is not relevant to this review.

Q28. Why is the concept of prudence important in public utility regulation?

[13] Order Approving New Annual Fuel Clause Adjustment Requirements and Setting Filing Requirements, MN PUC Docket No.E-999/CI-03-802, p. 9 (December 19, 2017).

A28. As natural monopolies, public utilities operate under a regulatory framework in which they are granted an exclusive franchise in exchange for submitting to government regulation. Because public utilities operate in a non-competitive environment and provide services that are generally thought to be essential, their ratepayers are captive to their costs and risks[14] and have little if any recourse should a utility manage costs and risks in ways that conflict with ratepayers' economic interests. In Minnesota, as in most jurisdictions, utility rates must be "just and reasonable."[15] Prudence reviews are how monopoly providers, including natural gas utilities, are held accountable and act as a partial substitute for competition. In sum, "prudent performance is a condition of the monopoly's exclusive franchise under the regulatory compact."[16]

Because ratepayers have much less information and capacity than utility managers to identify and manage risks, ratepayers must rely on regulators to assess managerial performance through a prudence review. In fact, a prudence review is one of the primary tools that can incentivize utilities to guard against excessive costs and ensure efficient use of resources[17] – but only if consistently and adequately conducted by regulators and backed by sufficient and appropriate enforcement, when necessary. As has been argued previously before the

[14] Janice A. Beecher and Steven E. Kihm, Risk Principles for Public Utility Regulators (First Edition), Michigan State University Press (2016), p. 5 ("Beecher and Kihm").
[15] Minn. Stat. § 216B.03.
[16] Beecher and Kihm (2016), p. 86.
[17] *Ibid.,* p. 87.

Commission (including by intervenors[18] during the proceedings ultimately finding imprudence in Xcel Energy's management of its Monticello nuclear power plant upgrades),[19] without the Commission's enforcement of the expectation for prudent behavior, utility performance will continue to inflate costs for customers.

Q29. How has the prudence standard been defined in the current proceeding?

A29. In its order opening the current prudence review, the MPUC stated:[20]

Every rate made, demanded, or received by a public utility must be just and reasonable. The burden to prove a rate is just and reasonable is on the utility seeking the change, and any doubt as to reasonableness will be resolved in favor of the consumer. In incurring costs necessary to provide service, utilities are expected to act prudently to protect ratepayers from unreasonable risks. Utilities that fail to do so will not be allowed to recover the costs of those failures. Just and reasonable rates are only realized through prudent utility action. To determine whether a utility acted prudently, regulators must comprehensively understand and analyze utility management decision making through a prudence review.

[18] "Initial Brief of the Office of the Attorney General-Antitrust and Utilities Division," Docket No. E002/CI-13-754 In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns, *Minnesota Public Utilities Commission* (October 31, 2014), p. 21.

[19] "Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes," Docket No. E-002/CI-13-754 In the Matter of a Commission Investigation into Xcel Energy's Monticello Life-Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns, *Minnesota Public Utilities Commission* (May 8, 2015).

[20] "Order Granting Variances Authorizing Modified Cost Recovery Subject to Prudence Review and Notice of and Order for Hearing," Docket No. G-999/CI-21-135 In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers, *Minnesota Public Utilities Commission* (August 30, 2021)

Q30. Can you elaborate on how the prudence standard has previously been defined and applied in Minnesota?

A30. Yes. In Minnesota, as in several other jurisdictions, there is longstanding precedent for prudence to be assessed based on "the facts that…[a utility] knew or should have known at the time of its action or decision."[21] The fact that a better outcome could have been reached in hindsight is not in itself permissible evidence in a prudence review; what matters is whether the utility acted reasonably based on the facts that it "knew or should have known" at the time. This is related to the concept of a "reasonable utility," which is expected to exercise "the care that a reasonable person would exercise under the same circumstances at the time the decision was made."[22] Finally, as explicitly emphasized by the Commission during the current proceeding, prudence requires protecting ratepayers from "unreasonable risks," which can only be accomplished through reasonable decision-making.[23]

Q31. How is the prudence standard related to managing risk?

A31. The expectation that utilities will protect ratepayers from unreasonable risks follows from the prudence standards, stated previously, that a utility will act reasonably based on what it "knew or should have known" at the time of its

[21] "Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes" (May 8, 2015).

[22] Administrative Law Judge Allen E. Giles, "Corrections to Report," Docket No. E-001/GR-91-605 Report Issued in the Matter of the Application of Interstate Power Company to Increase its Rates for Electric Service in the State of Minnesota, *Minnesota Public Utilities Commission* (April 17, 1992).

[23] "Order Granting Variances Authorizing Modified Cost Recovery Subject to Prudence Review and Notice of and Order for Hearing" (August 30, 2021).

decision and will exercise reasonable care. This includes acting on current information in order to make decisions about the future. While some facts may be readily apparent, other information may be obtained by producing forecasts or engaging with external experts. In other words, while utilities are not expected to perfectly predict the future, they are expected to exercise due diligence and to obtain and act upon the best possible information.[24]

Given that "[p]rudence calls for anticipating and managing risk with regard to investments and expenditures…[p]rudence is frequently judged in risk management terms" and "is a particularly important regulatory standard with regard to risk and risk allocation."[25] Risk allocation is largely determined by utility managers, and often involves striking a holistic balance between minimizing risk and cost. It would not be reasonable to expect utility managers to focus exclusively on minimizing costs, as such decisions may be unreasonably risky; it would also not be reasonable to focus exclusively on minimizing risk, as the least-risk option may be the costliest. Rather, utility managers must strike an appropriate balance between the simultaneous obligations to minimize risk and cost to ensure that rates are just and reasonable.

Given the complexity of balancing risk and cost, a prudence review will be most effective when regulators take a holistic view of a utility's actions and decisions. In limited instances, a utility may make a single decision that is clearly

[24] Beecher and Kihm (2016), p. 86.
[25] *Ibid.*

unreasonable. On other occasions, the confluence of multiple decisions may shift risk or cost to ratepayers to a degree that, when taken together, strikes an unreasonable balance between risk and cost or reflects insufficient or unreasonable planning – even if no single action does so on its own. This may include an assessment of the actions a utility took as well as those it neglected to take.

Q32. Is it the intervenor's responsibility to demonstrate that a utility acted prudently?

A32. No. Minnesota law, as upheld by the courts and previously enforced by the Commission, places the burden on each utility to demonstrate that its decisions were prudent based on what could have been reasonably known at the time. Minnesota law requires that "every rate made, demanded, or received by any public utility…shall be just and reasonable…Any doubt as to reasonableness will be resolved in favor of the consumer."[26] In *In re Northern States Power Co.*, the Supreme Court of Minnesota upheld that "by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses."[27] The MPUC has upheld this standard on numerous occasions, including by ruling that:[28]

[26] Minnesota Stat. § 216B.03.
[27] Justice Glenn E. Kelley, 416 N.W.2d "In re Northern States Power Co.," Supreme Court of Minnesota at 723 (1987).
[28] "Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes" (May 8, 2015).

A utility is in the best position to explain why its costs increased and to identify the amount of the increases. Allowing a utility to recover its imprudently incurred costs simply because public agencies or other intervenors are unable to precisely identify which imprudent actions caused which costs would not result in just and reasonable rates.

Establishing prudent behavior thus requires transparency on the part of the utility. To demonstrate prudence, a utility must provide regulators with a window into its decision making, including the information needed not only to assess a utility's decisions as prescribed but whether those actions were reasonable compared with potential alternatives. In a 2015 determination of imprudence, the MPUC ruled that "the evidence shows what the Company did; however, it does not explain any alternatives available as decisions were made…[the utility's] evidence thus lacks the transparency necessary to quantify the prudence of final costs."[29] To the extent that utilities do not provide the transparency necessary to demonstrate prudence, Minnesota law and precedent requires that any doubt is resolved in favor of the ratepayer. Under such circumstances, given its quasi-judicial function, the MPUC has significant latitude in determining a reasonable amount for potential cost disallowances.

Q33. Does prudence require perfect foresight or forecasting ability?

A33. No. As stated previously, no utility could reasonably be expected to perfectly predict the future. This is why hindsight is explicitly considered insufficient

[29] *Ibid.*

evidence for prudence determinations. Both my testimony and that of Bradley Cebulko focus on whether utilities acted reasonably based on what they "knew or should have known" at the time, as well as how they responded to certain circumstances that could not have reasonably been anticipated, such as the scale of the unprecedented price increases, once these conditions materialized.

Q34. Can you summarize your recommendations for how the MPUC should assess prudence in the current proceeding?

A34. Yes. The Commission should assess prudence in a manner that is consistent with Minnesota law and longstanding precedent in the state. The burden of proof is on each utility to demonstrate that it acted as a "reasonable utility" – that is, with the due care that a reasonable person in similar circumstances would have exercised, based on the information that was known or knowable at the time. This includes acting reasonably on information regarding conditions that had already materialized as well as those that could reasonably be foreseen – even if substantially underestimated or imprecisely quantified. A reasonable utility would make an effort to have adequate plans for infrequent but likely events such as price spikes – regardless of the degree of those spikes. These plans would include, at a minimum, conducting due diligence to anticipate and manage risks, and an expectation to act on that information as a reasonable person would in similar circumstances. While a utility could not reasonably be expected to anticipate the exact timing and extent of unprecedented price spikes, a reasonable utility would respond to warnings about conditions that are widely known to impact prices, have a plan to mitigate the impact to customers, be concerned with accurate load forecasts, and economically dispatch all reasonable resources. A reasonable utility would exercise due care to balance both risk and cost and operate under a regulatory framework that shares risk reasonably between ratepayers and shareholders. To the extent that a utility does not provide sufficient transparency to demonstrate that its actions were prudent when compared with potential alternatives, Minn. Stat. 216B.03 requires the MPUC to resolve any doubts in favor of the ratepayer, and the MPUC has considerable latitude in quantifying potential cost disallowances.

A. Prudency Analysis

Q35. What is the purpose of this subsection of your testimony?

A35. While many of the prudency issues relevant to these cases require in-depth industry analysis, which is provided in Witness Cebulko's testimony, there are also policy and regulatory issues related to how the Commission should determine prudence. This subsection addresses policy and regulatory issues related to the determination of prudent decision making.

Q36. The Companies state in several places throughout their testimonies that a utility's filing was approved by the Commission. For example, each utility testifies that the Commission reviews and approves its gas procurement and

hedging plans, amongst other filings.[30] How is the Commission's approval of a utility filing related to prudency?

A36. It is not. Prudency is determined on a case-by-case basis and is most frequently related to utility manager's decision-making, which is distinct from most, if not all, regulatory filings that would be approved by the Commission. This is because a regulatory filing is often an account of what occurred, or a plan for the future, not the decision making involved. In a prudence review, a utility's decision making is what is of concern. For that reason, Commission approval of a utility *filing* should not be confused with a determination or indication of prudence of a utility *decision* or *action*.

Q37. The Commission has stated that "[t]he burden to prove a rate is just and reasonable is on the utility seeking the change."[31] Did each utility provide sufficient information to support a conclusion that its decision making was prudent?

A37. No. For each utility, we found that the utility omitted critical information. Because the decision-making process at issue is extremely complex and interconnected, omitting certain details can have the effect of undermining a utility's argument as a whole. The utilities have not adequately explained their

[30] Direct Testimony and Schedules of Jason M. Ryan on Behalf of CenterPoint Energy, MPUC Docket No. G-008/M-21-138/OAH Docket No. 71-2500-37763, (Oct. 22, 2021) ("Ryan Direct"), p. 34-35, lines 18-2.; Direct Testimony and Schedules of Theodore T. Eidukas on Behalf of Minnesota Energy Resources Corporation, MPUC Docket No. G011/CI-021-611/OAH Docket No. 71-2500-37763, (Oct. 22, 2021) ("Eidukas Direct"), p. 16-17, lines 9-2; Direct Testimony and Schedules of Allen D. Krug on Behalf of Northern States Power Company, MPUC Docket No. G002/CI-021-610/OAH Docket No. 71-2500-37763 (Oct. 22, 2021) ("Krug Direct") p. 17, lines 10-22.
[31] "Order Granting Variances Authorizing Modified Cost Recovery Subject to Prudence Review and Notice of and Order for Hearing." (August 30, 2021)

failures to react to price increases, adaptively manage their operations as conditions evolve, accurately forecast load, and maximize storage, curtailment, and peaking plants.

Q38. Let's consider each of those failures in turn. Have the utilities explained why they did not react to price increases?

A38. No. The utilities have not explained why they did not react to spot prices that had already reached a 167% (Emerson), 514% (Ventura) and 472% (Demarc) increase over 5-year annual average prices at the time of their procurement decisions on February 12, and which had reached unprecedented levels at the time of their procurement decisions on February 16. [32] The utilities' explanation that they could not predict the extent of the price increases on February 12[33] sidesteps their more pertinent failure to react to the price increases and other facts, such as production freeze offs and extreme regional weather forecasts, that had already materialized at that time, as well as their failure to react to the unprecedented price increases that had become known by February 16.

[32] S&P Capital IQ Pro Historical Spot Natural Gas Index.

[33] Direct Testimony and Schedules of Jeffrey T. Toys on Behalf of CenterPoint Energy, MPUC Docket No. G008/CI-021-138/OAH Docket No. 71-2500-37763 (Oct. 22, 2021) ("Toys Direct"), p. 3, lines 2-3; Direct Testimony and Schedules of Sarah R. Mead on Behalf of Minnesota Energy Resources Corporation, MPUC Docket No. G011/CI-021-611, OAH Docket No. 71-2500-37763, (Oct. 22, 2021) ("Mead Direct"), p. 41, lines 20-21; Direct Testimony and Schedules of Richard L. Derryberry on Behalf of Northern States Power Company, MPUC Docket No. G002/CI-21-610/OAH Docket No. 71-2500-37763, (Oct. 22, 2021) ("Derryberry Direct"), p. 16, lines 18-19

Q39. The Companies repeatedly state that they had no reason to expect that natural gas prices would exceed $200/Dth.[34] Please discuss the distinction between perfect foresight and the concept of prudent decision-making.

A39. The utilities appear to be intentionally blurring the lines between perfect foresight and the reasonable management of economic risk to suggest that, because it is impossible to perfectly forecast extreme price spikes or weather conditions, they cannot reasonably be expected to manage risk based on information that is "known and knowable" at the time of their actions and decisions. Such a conception of prudence would be contrary to this Commission's expectation that utilities "protect ratepayers from unreasonable risks."

The utilities' consistent plea that they could not have foreseen unprecedented prices of over $200/Dth is not the focus of this prudence review. This is a red herring. No regulator could reasonably expect utilities to perfectly forecast prices or foresee that price would reach unprecedented levels. The expectation is for utilities to have a plan for potential price spikes, make a reasonable effort to obtain information about future conditions, including prices, and to react to that information. The fact that prices may turn out to be even higher than anticipated does not change this expectation. As can be seen in CenterPoint Witness Ryan's testimony, Minnesota has seen prices exceeding $40/Dth twice in the last seven years.[35] In addition to making a reasonable effort to anticipate future conditions,

[34] Eidukas Direct, p. 21-22, lines 4-2.; Ryan Direct, p. 36, lines 1-15; Derryberry Direct, p. 2-3, lines 22-10.
[35] Ryan Direct, p. 37, line 1, Figure 2.

utilities are also expected to react to conditions as they evolve in real time and after they have materialized.

There is also not an expectation for utilities to perfectly forecast the weather or load. The obligation to provide just and reasonable rates, however, necessarily implies that there is such a thing as a "reasonable" forecast; if this were not the case, utilities would be permitted to substantially over-procure in order to meet unreasonable load projections, which would lead to unjust and unreasonable rates. A prudence review may thus assess not whether forecasts were perfect, but whether they were reasonable. Although it may be challenging to precisely quantify "reasonable" risk management, this does not dismiss utilities or regulators from their obligation to "protect ratepayers from unreasonable risks." As stated previously, the Commission has upheld that the burden is on utilities – not regulators or intervenors – to provide the "transparency necessary to quantify the prudence of final costs."[36]

Q40. Did the utilities adaptively manage their operations prior to, and during, the Event to reasonably manage costs and reliability for customers?

A40. No. The clearest example is the utilities' collective lack of action on February 16 when developing a supply plan for gas day February 17. To start, the utilities' testimony focuses on what they did and did not know leading into the four-day weekend. As CUB Witness Cebulko and I show in our testimonies, the utilities did not act prudently during the time leading up to the storm. However, their most

[36] *Ibid.*

egregious collective action was their unwillingness to significantly change course on February 16 when they developed a supply plan for gas day February 17. On February 16, the utilities knew that prices had reached unprecedented levels, they knew that they had incurred incremental costs in the hundreds of millions of dollars, and they knew that there had been significant well head freeze-offs in Texas and Oklahoma. And yet, the utilities continued not to maximize curtailments, peaking facilities, and their storage to mitigate the cost impact to customers. They did not significantly modify their approach and, as a result, they continued to incur tens of millions of dollars in fuel costs that they are now passing through to ratepayers.

Q41. Were the utilities aware that natural gas prices were already high when they developed their supply plans on February 12 and February 16 during the Event, and did they have any reasons to believe that natural gas prices would decrease during the period?

A41. The utilities were aware that prices had reached approximately 5 times the prevailing rate, or $15/Dth, when they developed their supply plans on February 12, and that prices had reached unprecedented levels when they developed their supply plans on February 16. For example, CenterPoint was told by a gas broker that prices were "scary" at 7:12 AM on February 11.[37] The utilities have not provided any reasons to expect that prices would decrease when they developed

[37] *See* CenterPoint Energy's response to OAG IR 117, Attachment 5 in Docket No. 21-135. Available here: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B1048817A-0000-CB97-B67A-B4DA701FE8EB%7D&documentTitle=20217-175866-05

their supply plans on these dates, and, if prices were not to decrease, why their actions were reasonable. The utilities have also neglected to address why their actions were reasonable in light of the multiple warnings that they had received about colder-than-average weather forecasts and potential supply constraints – both issues which would be expected to push prices upward, all else constant.

Q42. Did the utilities accurately forecast their customers' load prior to and during the Event?

A42. MERC's load forecasts for the key planning dates of February 14 and 17 were highly inaccurate. As explained in the testimony of CUB Witness Cebulko, MERC over-projected load for its Sales customers, for whom the Company is responsible for procuring supply, by 10% and 34% on these dates, respectively.[38] Xcel chose to base its supply plan on load forecasts that included interruptible customers that the utility would later curtail. Thus, the load forecast served as an inaccurate tool for making supply decisions.

Q43. Have MERC and Xcel explained their failure to accurately forecast their customers' load prior to and during the Event?

A43. No. MERC has not explained why the Company's highly inaccurate load projections on key planning dates were reasonable; in particular, MERC has failed to sufficiently explain why it over-projected load on February 17 to a degree (34%) that appears to be an anomaly for the Company.[39] Xcel has not explained

[38] Cebulko Direct, p. 39, lines 6-10.
[39] Cebulko Direct, p.40, lines 2-18.

why it was prudent to procure supply for non-firm customers that the utility planned to curtail.

Q44. Did the utilities maximize their use of storage during the Event?

A44. Because MERC and Xcel's load over-projections resulted in excess procurement in the spot market, they were unable to utilize as much storage as would have been possible with better planning and less over-supply.

Q45. Have MERC and Xcel acknowledged this connection between accurate forecasting and storage?

A45. No. Although MERC and Xcel have correctly identified how reductions in storage were needed to balance the system, they have neglected to mention how their over-procurement of spot gas contributed to the need to ease off storage. Both utilities have focused on how the requirement that purchases over each day of the long weekend be "ratable," or equivalent in daily volume, necessitated over-procurement on the non-peak dates of the long weekend. As demonstrated by CUB Witness Cebulko, while some level of over-procurement on the non-peak dates was necessary, MERC and Xcel could have reasonably reduced over-procurement and increased storage utilization with better planning to the peak date of February 14.[40] The witnesses for Xcel and MERC have claimed that each of these utilities maximized storage during the Event because they maximized

[40] Cebulko Direct, p.43-44.

storage *nominations* during the planning phase.[41] This proceeding is not investigating whether the utilities *planned* to maximize storage during the Event, but whether they actually maximized storage withdrawals in practice. MERC and Xcel have not met their burden of demonstrating they sufficiently maximized storage withdrawals during the Event.

Q46. Did the Companies maximize curtailments during the Event?

A46. Xcel came the closest of the three utilities, maximizing curtailments on each day of the Event other than February 17, when the Company began to release customers from curtailment. With better planning, Xcel could have offset additional expensive spot purchases – which had already risen to unprecedented prices at the time of its procurement decision – by maximizing curtailment on this date.

CenterPoint requested curtailments on 53 percent of interruptible load on February 14 but requested less than 40 percent curtailment on February 13 and 15 and minimal (less than 5 percent) curtailment on February 16-17.

MERC did not request curtailments over the Event.

Q47. Why did MERC not curtail interruptible load during the Event?

[41] Direct Testimony and Schedules of Steven H. Levine on Behalf of Northern States Power Company, MPUC Docket No. G002/CI-021-610/OAH Docket No. 71-2500-37763, (Oct. 22, 2021) ("Levine Direct"), Schedule 2, Review of NSPM's Natural Gas Procurement for Retail Natural Gas Customers, p. 42, paragraph 64; Direct Testimony and Schedules of Timothy C. Sexton on Behalf of Minnesota Energy Resources Corporation, MPUC Docket No G011/CI-21-611/OAH Docket No. 71-2500-37763, (Oct. 22, 2021) ("Sexton Direct"), p. 32, lines 12-14

A47. MERC has claimed that the Company's tariff precludes the utility from curtailing for economic reasons[42] – a reading which does not accurately reflect the plain language in its interruptible tariffs. One of MERC's interruptible tariffs applies to "[c]ustomers taking natural gas service which may be interrupted, curtailed or discontinued at any time at the option of the Company in accordance with the provisions herein."[43] This language is similar to that of CenterPoint and Xcel's tariffs, neither of which prohibit interruption for economic reasons.[44] MERC has suggested that Tariff Sheet No. 8.40-8.41a, which states that "[t]he following priorities will be followed when operational and supply conditions require service interruptions with highest priorities listed first,"[45] distinguishes supply conditions from pricing, and excludes the latter.[46] However, "supply conditions" are not defined in the tariff, and are reasonably interpreted to include price – particularly given that the tariff allows MERC to discontinue "at any time at the option of the Company."[47] MERC's tariff does not state that the Company can only interrupt for reliability reasons, nor does it define reliability.

Q48. Does MERC's explanation align with your understanding of MERC's interruptible tariffs and how other interruptible tariffs are structured?

[42] Eidukas Direct, p. 28, line 8.
[43] See MERC Tariff and Rate Book, General Rules, Regulations, Terms and Conditions ("MERC Rules and Regulations") , No. 8.01 at https://www.minnesotaenergyresources.com/company/tariffs/rules.pdf.
[44] See CenterPoint Energy Gas Rate Book at https://www.centerpointenergy.com/en-us/Documents/RatesandTariffs/Minnesota/CPE-MN-Tariff-Book.pdf and Xcel Energy Minnesota Gas Rate Book at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Mg_Section_5.pdf.
[45] MERC Rules and Regulations, No. 8.40-8.41a..
[46] MERC, Response to OAG IR#108, MPUC Docket No. G-999/CI-21-135.
[47] MERC Rules and Regulations, No. 8.40-8.41a.

A48. No. Interruptible customers receive a discounted rate in exchange for assuming the risk of interruption during reliability, supply, and economic events. Given the significantly escalated spot prices on February 12 and unprecedented prices on February 16, there were sound economic reasons to curtail customers. If utilities are not willing to interrupt customers during such events, their customers should not be receiving a credit for assuming the risk of interruption.

Q49. Did you find deficiencies in CenterPoint's explanations for why it did not use LNG and propane peak shaving resources to alleviate the cost impact to customers?

A49. Yes. CenterPoint argued that peaking facilities should only be used for maintaining reliability and should not be dispatched for responding to high prices.[48] This is another example of one of the utilities making overly conservative decisions that do not weigh cost to a reasonable extent.

CenterPoint argues that its peaking facilities are not designed or planned to address pricing events and that the utility must reserve its peaking facilities to address the possibility of future cold events.[49] As CUB Witness Cebulko discusses in detail, CenterPoint's statements are misleading. CenterPoint is either suggesting that the plants are incapable of being economically dispatched or that the utility is unable to optimize its supply portfolio to manage both risk and cost. Neither should be true for a reasonable utility.

[48] E.g. Direct Testimony and Schedules of John W. Heer on Behalf of CenterPoint Energy, MPUC Docket No. G008/CI-021-138/OAH Docket No. 71-2500-37763 (Oct. 22, 2021) ("Heer Direct") p. 20, line 18, to p. 21, line 8.
[49] Heer Direct p. 33, line 13-23.

Additionally, CenterPoint's position in this case appears to directly conflict with conversations its gas purchasers had with gas brokers. While CenterPoint was looking for weekend gas, an employee stated "with prices as high as they are. We are going to hold off and look at cranking up LNG and propane."[50] This indicates that decision-makers within CenterPoint – trusted to purchase millions of dollars in fuel – are considering price and dispatch of LNG and propane while making supply decisions. CenterPoint does not address this in direct testimony.

Finally, the Company rarely uses its peaking facilities and was in no danger of depleting the resource.[51] On February 12, 2021, the utility still had a significant portion of its annual inventory for its propane and LNG facilities. Since 2010, CenterPoint had called upon its LNG facility 9 times after February 14 of a winter season.[52] From 2010 – 2020, CenterPoint has only dispatched from its peaking propane facilities a cumulative total of 166,341 Dth from 2010-2020, or 15 percent its propane capacity for a *single year*. From 2010-2020, CenterPoint dispatched a cumulative total of 673,262 Dth from its LNG facility, which is only 67% its *annual* capacity of 1,000,000 Dth. Simply put, CenterPoint seldomly uses these robust facilities that could have saved customers tens of millions of dollars.

Q50. Has Xcel provided a sufficient explanation as to why the Company took its propane facilities offline in January 2021?

[50] *See* CenterPoint Energy's response to OAG IR #117, Attachment 5 in Docket No. 21-135. Available here: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B1048817A-0000-CB97-B67A-B4DA701FE8EB%7D&documentTitle=20217-175866-05
[51] Cebulko Direct, p. 87, lines 15-19.
[52] Cebulko Direct, p. 88, lines 1-2.

A50. No. CUB Witness Cebulko testifies that he is uncertain if Xcel prudently managed and maintained its LNG facility, as the Company has not provided sufficient information and justification in its testimony. However, it is clear that Xcel has not justified its voluntary removal of its two propane facilities from use at the beginning of January 2021. Xcel only testifies that, during an inspection of the plants that was initiated because of the problem at the LNG facility, Xcel found that "additional investments needed to be made at Sibley and Maplewood, which also were nearing the end of their life expectancies, so we can safely operate them for many more years."[53] Xcel does not testify what investments needed to be made, if the plants were unable to operate or if human life was in danger, a cost estimate, a timeline for repair, alternatives considered, or any other basic information that is necessary to determine if the utility acted prudently.

V. <u>The Role of Natural Gas Integrated Resource Planning</u>

Q51. What is the purpose of this section?

There are two purposes of this section. First, to discuss the role and benefits of long-term planning for mitigating the impact of price spikes to customers. Second, to explain that, because the gas utilities do not file IRPs, it is all that much more important for the gas utilities party to this proceeding to explain how

[53] Yehle Direct, p. 18-19, lines 22-2.

their resource planning supported and allowed for prudent decision making prior to and during the Event.

Q52. What is a natural gas integrated resource plan (IRP)?

A51. A natural gas IRP has the same purpose as an electric IRP – it is a long-term resource plan that assesses the utility's future demand and identifies a path, or pathways, for how the utility will meet demand. The integrated part of the IRP is the process for integrating supply- and demand-side resources into a service for customers.

In general, IRPs are public processes with involvement from the stakeholder community, and the bulk of the utility's analysis is open and transparent to the public.

Q53. What are the components of a gas IRP?

A52. It depends on the policies and preferences of the state and commission, but there are some analyses that are universal to an IRP. Those include a load forecast, assessments of the utility's existing supply- and demand-side resources, an assessment of the planning environment (existing local, state, and federal policies that impact the utility's planning and operations) an assessment of future supply- and demand-side resources, and a portfolio section model run. Optional analyses include distribution system planning and sensitivity analyses and alternative scenarios.

Q54. What are some common sensitivity and alternative scenario analyses in natural gas IRPs?

A53. Sensitivities are used to understand the impact to the utility if key variables change. Some of the most common sensitivity analyses include capacity alternatives to the preferred portfolio,[54] alternative gas prices, alternative load forecasts, and alternative design day conditions.

Utilities can also model alternative scenarios if they are changing more than one variable. Increasingly, utilities can run emissions reduction scenarios (or sensitivities) that model the cost and emissions of certain portfolios that prioritize emissions reductions. I have also seen utilities use alternative scenarios to understand the various pathways for meeting state policy. More directly related to our purposes here, the utility could on its own, or at the request of a stakeholder or the commission, could test the robustness of a utility's preferred portfolio against various magnitudes of price spikes, pipeline outages, or other major disruptions.

Q55. How would a natural gas IRP help protect ratepayers from future price spikes?

A54. An IRP is a public planning process. It is an opportunity for the utility to explain its planning and operations to the public, interested stakeholders, and the Commission. Most of the key issues that have percolated into this case would be addressed in an IRP. For example, in an IRP, a utility could test the robustness of

[54] Oftentimes there are multiple upstream pipeline projects being planned, but the utility does not control which pipeline is ultimately built.

various supply- and demand-side resource portfolios against various design days or price spikes. Let's take two hypothetical resource portfolios: Portfolio A is cheaper than Portfolio B over the 20-year planning horizon under normal operating conditions. But, if in another model run, the utility includes one or two extraordinary price spikes at various intervals, Portfolio B may be the cheaper portfolio. The utility and the stakeholder community can discuss the trade-offs between the two portfolios, and then the utility will have to justify to the Commission why its particular portfolio is in the public interest. Other topics that would be discussed in an IRP include the value of demand-side resource towards meeting design day conditions, the costs and benefits of various supply basins, and capacity options for meeting load growth, such as additional pipeline capacity, storage, or peaking facilities.

An IRP won't prevent another price spike, but robust, public planning puts the utility, the Commission, and community into a better position to mitigate the impact to customers of those price spikes.

Q56. How does an IRP inform a prudence review such as this one?

A55. An IRP also serves as an information repository that could help both the utility and intervenors during a prudence review. Intervenors have a filing to review to better understand how a utility intends to use its storage, interruptible tariffs, and peaking facilities to meet demand. For a utility, an IRP is an opportunity to lay the groundwork of its prudence demonstration by explaining its opportunities, risks, and considerations in an environment free of the demands of an adjudication.

Minnesota Statute 216B.2422 currently requires regulated electric utilities, but not regulated gas utilities, to file IRPs on a regular basis. Because none of the gas utilities party to this proceeding had filed an IRP with the Commission prior to the Event, intervening parties and the Commission lack transparency into the utilities' internal resource plans. I do not make this statement to suggest the utilities acted imprudently prior to the Event by not filing an IRP with the Commission. Rather, I make this statement to suggest that – because the utilities have not filed (and have not been required to file) an IRP that is subject to review and analysis by the public, interested stakeholders, and the Commission – it is all that much more important for the gas utilities party to this proceeding to now explain how their resource planning prior to the Event supported and allowed for prudent decision making prior to and during the Event. In particular, the utilities bear the burden of demonstrating they took prudent actions to prepare for extreme weather events and/or extreme price spike events – or to demonstrate they acted prudently despite not having planned for such events. As my colleague Witness Cebulko and I demonstrate throughout our testimonies, the utilities did not meet that burden.

VI. <u>Conclusion</u>

Q57. Does this conclude your testimony?

A56. Yes.

Exhibit___(REN-D), Schedule 1

Ron Nelson

Senior Director

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Education

MS, Agricultural and Resource Economics
Colorado State University, 2013

BA, Environmental Economics
Western Washington University, 2011

Work Experience

Senior Director

Strategen / Portland, OR / 2018 - Present

+ Subject matter and testimony expert in advanced rate design, embedded and marginal cost of service modeling, performance-based regulation, and DER integration and compensation.
+ Designing policies and programs to advance deployment of distributed energy resources, demand-side management programs, energy storage and grid integration

Economist

Minnesota Attorney General's Office / St. Paul, MN / 2013 - 2017

+ Provided expert testimony on cost of service modeling, rate design, grid modernization and utility business models
+ Analyzing issues related to conservation incentive programs, value of solar, grid modernization, performance-based regulation, renewable energy program design, and MISO

Graduate Research Associate

Colorado State University / Fort Collins, CO / 2011 - 2013

+ Analyzed the ongoing impact of the 2011 drought in Colorado
+ Wrote and obtained grants, setting and managing their budgets, and delivering final research projects

Economic Research Assistant

Washington State University / Mount Vernon, WA / 2009 - 2011

+ Developed a payment for ecosystem services program for The Nature Conservancy
+ Established ecological metrics that could be monetized into economic benefits and estimating the benefits and costs to farmers

Ron Nelson

Senior Director

Expert Testimony

Green Mountain Power Corporation (DKT: 21-3707-PET) On Behalf of Green Mountain Power
Multi-Year Regulation Plan
Direct Testimony with Matt McDonnell

Public Service of Oklahoma (DKT: 202100055) On Behalf of AARP
ECOSS and Rate Design
Responsive Testimony

Duquesne Light Company (DKT: R-2021-3024750) On Behalf of the PA OCA
Transportation Electrification, Load Control
Direct | Surrebuttal (note: please type in the docket number, the testimony cannot be directly referenced)

PECO (DKT: R-2021-3024601) On Behalf of the PA OCA
Transportation Electrification, Load Control
Direct (note: please type in the docket number, the testimony cannot be directly referenced)

Rocky Mountain Power (DKT: 20-035-04) On Behalf of the Utah Office of Consumer Services
Embedded COS, Rate Design, and AMI rollout
Direct

Minnesota Power* On Behalf of the MN CUB
ECOSS and low income rate design

Pennsylvania Power and Light: DER Management Petition (DKT: P-2019-3010128) On Behalf of the PA OCA
DER integration
Direct | Surrebuttal (note: please type in the docket number, the testimony cannot be directly referenced)

Public Service of New Hampshire (dba Eversource Energy) (DKT: DE 19-057) On Behalf of the NH OCA
Embedded and marginal COS, Rate Design, and PBR
Direct

Liberty Utilities (DKT: DE 19-064) On Behalf of the NH OCA
Marginal COS, Rate Design, decoupling and PBR
Direct

Oklahoma Gas and Electric (DKT: 201800140) On Behalf of AARP
Rate Design and CCOSS
Direct

Vectren Energy Delivery of Ohio (DKT: 18-0298-GA-AIR) On Behalf of the Environmental Law and Policy Center
CCOSS and Rate Design
Direct | Supplemental | Case link

*Settled before direct was filed

Ron Nelson
Senior Director

Expert Testimony Continued

Commonwealth Edison (DKT: 18-0753) On Behalf of the IL AG
Distributed Generation Rebates and Smart Inverter Specifications
Direct | Rebuttal | Case link

Ameren Illinois Company (DKT: 18-0537) On Behalf of the IL AG
Distributed Generation Rebates and Smart Inverter Specifications
Direct | Rebuttal | Case file

Public Service Company of Oklahoma (DKT: 201800096) On Behalf of AARP
Formula Rates, Performance Metrics, Rate Design, and CCOSS
Direct

Oklahoma Gas and Electric (DKT: 201700496) On Behalf of AARP
CCOSS and Revenue Apportionment
Responsive | Case link

Minnesota Power (DKT: E-002/GR-16-664) On Behalf of the MN OAG
CCOSS, Rate Design, and the Utility Business Model
Surrebuttal | Rebuttal: | Testimony | Case Link

Otter Tail Power (DKT: E-002/GR-15-1033) On Behalf of the MN OAG
Marginal and Embedded CCOSS and Rate Design
Opening Statement | Direct | Rebuttal | Case link

Xcel Energy (DKT: E-002/GR-15-826) On Behalf of the MN OAG
CCOSS, Rate Design, and Performance-Based Regulation
Direct | Rebuttal | Surrebuttal |Case link

Minnesota Energy Resources Corp. (DKT: G-011/GR-15-736) On Behalf of the MN OAG
CCOSS and Rate Design
Direct : | Rebuttal | Surrebuttal | Case link

CenterPoint Energy (DKT: E-002/GR-15-424) On Behalf of the MN OAG
CCOSS and Rate Design
Opening Statement | Direct | Rebuttal | Surrebuttal | Case link

Dakota Energy Association (DKT: E-002/GR-14-482) On Behalf of the MN OAG
CCOSS and Rate Design
Direct | Rebuttal | Surrebuttal | Case link

Xcel Energy (DKT: E-002/GR-13-868) On Behalf of the MN OAG
CCOSS and Rate Design
Direct | Rebuttal | Surrebuttal: Case Link

Ron Nelson

Senior Director

Expert Testimony Continued

Minnesota Energy Resources Corp. (DKT: G-011/GR-13-617) On Behalf of the MN OAG
CCOSS
Direct | Surrebuttal | Case Link

CenterPoint Energy (DKT: G-008/GR-13-316) On Behalf of the MN OAG
CCOSS
Direct: | Surrebuttal | Case Link