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May 27, 2021

—Via Electronic Filing and U.S. Mail—

Steven M. Kahl, Executive Director
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

RE: EXTREME COLD WEATHER EVENT INVESTIGATION (NATURAL GAS)
RESPONSE TO FOLLOW-UP QUESTIONS (CASE NOS. PU-21-102, PU-21-9)

Dear Mr. Kahl:

Northern States Power Company (NSP), doing business as Xcel Energy, herewith submits to the North Dakota Public Service Commission responses to questions submitted to the Company by Victor Schock on May 24 and 25 regarding the impacts of the extreme cold weather events of February 2021 on our natural gas business.

The questions and responses follow below:

1. *MDU's residential impact is approximately $90 per customer versus NSP's $240 per customer. Other than the size difference in natural gas storage, what other reason would NSP offer as to why NSP was not able to obtain as favorable gas supply contracts versus MDU, particularly considering NSP's size?*

   We believe MDU's substantial storage position was the primary factor in helping them avoid higher natural gas acquisition costs during the February extreme cold weather event. As explained in our comments during the Commission's May 5 Informal Hearing and in response to question 9 below, nearby storage service is fully subscribed and therefore the Company cannot easily increase its storage without significant cost to our customers.

   That said, the geographic variability of cold weather may also have contributed to MDU's avoidance of higher costs. The coldest conditions appear to have occurred in MDU's service areas earlier in February than it did

in NSP's service areas. MDU's peak demand period was from February 6 – 15, whereas NSP experienced significant firm demand from February 13 – 17. As a result, MDU bought most of its additional gas for peak demand before the price spikes on February 12 (for the gas purchased for Presidents Day weekend) when the extreme cold (and higher gas demand) moved into a larger portion of the U.S. along with the consequent gas production constraints. Because MDU purchased less additional gas supply during the extreme pricing days they undoubtedly benefitted from a smaller cost exposure.

2. *Similar to question 1, please explain why the Great Plains Natural Gas and Dakota Natural Gas systems gas cost for February 2021 were drastically less than NSP's, considering they are much smaller systems with limited or no availability of storage and are connected to similar pipeline systems?*

   The Great Plains (GP) and Dakota Natural Gas (DNG) gas loads are significantly smaller than NSP's. As reported in their filings, GP's daily demand is roughly 2,000 Dth during the winter, while DNG's daily demand is roughly 30 Dth. By comparison, over Presidents Day weekend, NSP's demand was nearly 700,000 Dth per day. GP's average daily demand is roughly .003% of the size of NSP's Presidents Day loads. GP's reported an under-recovery of roughly $600,000, while DNG reported almost no under-recovery due to its very small demand load. The small additional quantities these companies burned over Presidents Day weekend would not have amounted to significant dollar cost exposures. Both of these utilities are small enough that it is possible they have engaged a marketer to supply all their gas needs with a type of fixed-price contract. In fact, the variable quantities for these two utilities are so small that it could be considered "rounding" for the marketer.

3. *In the original responses you noted that there was storage gas used for both natural gas customers and for power generation. Is the storage contracted separately for electric vs natural gas sides?*

   Yes, storage service is contracted separately for natural gas distribution customers and power generation fuel supply.

4. *Was the storage extraction capability maxed out during the cold weather event? Meaning, was the maximum daily throughput utilized?*

   Yes, NSP started each day using all of the contracted maximum daily withdrawal capacity. It's important to note, however, that our storage service

allows withdrawals *and* injections on a daily basis, so storage has an important role to balance our natural gas system. Therefore, at the end of each day, some unburned gas was returned to storage causing the final reported storage quantity to vary each day.

NSP's first goal during a cold event is to ensure uninterrupted service to our firm customers so that they remain warm and safe. Providing such reliable service requires the Company to include a reserve margin, or a "safety net," when acquiring gas supplies during a high demand event. One illustration of the need for a reserve margin involves temperature variations. NSP's gas planning modeling predicts that (at the temperatures ranges experienced during the pricing event) a five-degree temperature change will cause a roughly 40,000 Dth change in customer demand. In other words, if the meteorologist predicts the next day's average daily temperature will be minus 10° but the actual average temperature is minus 15°, we would expect an additional demand of roughly 40,000 Dth. Thus, if we had purchased gas to precisely meet a minus 10° demand load, we would have been short 40,000 Dth, threatening loss of service to our customers or substantial penalties from the pipeline company for burning more gas than we delivered to the pipeline that day. In a day when we already fully scheduled our Northern storage, our only recourse would be to attempt to purchase gas on the intra-day market, where it may not be available. Accordingly, we plan to acquire additional supplies each day during a cold weather event with the expectation that we will return some gas to storage at the end of each day.

5. *What types of gas purchases does NSP utilize? Daily, 1st of the month, etc?*

NSP purchases natural gas using first-of-the-month pricing and daily pricing. The Company purchases some gas in seasonal packages, some in monthly packages, and some on a daily basis. The various terms and pricing strategies are used in combination to spread the supply and pricing risk over a variety of methods. The Company is happy to provide the Commission additional detail on its Natural Gas Procurement Policy if it is of interest.

6. *Did natural gas power generators on NSP's system pay the same amount for natural gas that was experienced for natural gas customer use?*

We are unaware of what other power generators paid for natural gas; however, we can address gas acquisition for NSP-owned generation. NSP System Generation has substantial back-up fuel oil reserves at many plant sites, which it used over Presidents Day weekend to avoid paying the

extremely high natural gas prices being demanded in the market. Accordingly, NSP Generation primarily relied on baseload and storage gas and fuel oil to operate its facilities with very little daily gas purchases needed.

7. *Please provide the daily hub gas prices for the month of February.*

Day	NNG Demarc (Per Dth)	NNG Ventura (Per Dth)
2/1/21	$2.62	$2.60
2/2/21	$2.74	$2.72
2/3/21	$2.91	$2.90
2/4/21	$2.86	$2.87
2/5/21	$3.02	$3.22
2/6/21	$3.78	$3.85
2/7/21	$3.78	$3.85
2/8/21	$3.78	$3.85
2/9/21	$3.72	$4.20
2/10/21	$3.86	$4.06
2/11/21	$6.61	$6.91
2/12/21	$15.68	$15.42
2/13/21	$231.67	$154.91
2/14/21	$231.67	$154.91
2/15/21	$231.67	$154.91
2/16/21	$231.67	$154.91
2/17/21	$133.64	$188.32
2/18/21	$26.95	$19.46
2/19/21	$6.05	$5.98
2/20/21	$3.99	$3.74
2/21/21	$3.99	$3.74
2/22/21	$3.99	$3.74
2/23/21	$2.66	$2.68
2/24/21	$2.70	$2.69
2/25/21	$2.63	$2.63
2/26/21	$2.47	$2.46
2/27/21	$2.47	$2.46
2/28/21	$2.47	$2.46

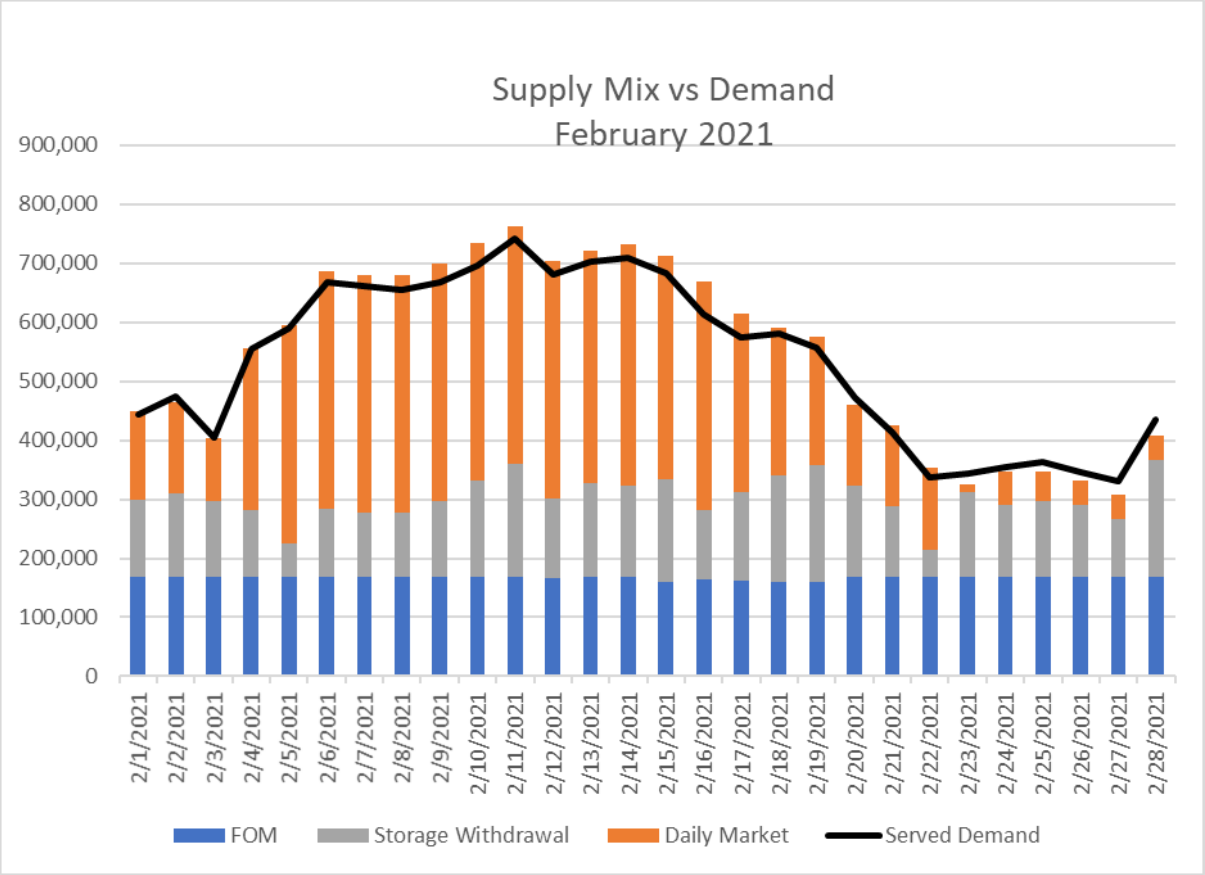
8. *What was the gross cost of gas that was used from storage on average?*

   For February 13 – 17, NSP reported $1.4 million of storage gas costs at an average rate of $1.89 per Dth.

9. *Can NSP provide a slide similar to the one attached showing the different types of gas purchases to serve customer needs in February?*

   See Figure 1 below. NSP fully used its storage assets on these days. However, customer demand was so great that we were required to purchase additional quantities in the daily market. While holding additional storage capacity would offer additional price mitigation on days of extreme price spikes, the additional cost of holding additional capacity for rare price spikes would likely not be economically justified.

Figure 1



The availability of underground storage service is limited and therefore would come at an increase in annual costs for our customers. Storage services are available from other providers under existing tariffs, specifically at fields located in Michigan. These fields would require additional transportation capacity, and the associated demand costs to transport that additional gas to our service areas. As a very rough estimate of cost effects, to expand our deliverable storage capacity from 30% to 50% of Design Day needs with capacity from ANR Pipeline would require an increase of approximately 188,000 Dth of withdrawal storage capacity, with associated transport on ANR Pipeline and Northern Border Pipeline for an additional annual demand cost of approximately $21 million per year. This estimated cost increase represents a 24% annual increase in customer costs over the roughly $68 million costs we incur for pipeline transportation and storage demand charges today. This rough estimate assumes available transportation and storage capacity from all providers without the need for new construction. Any required construction would add significant costs to the estimate.

For the Commission's reference, and to provide additional context, we provide below two additional charts which indicate that, in general, NSP's gas procurement practices result in some of the lowest natural gas costs in North Dakota and the region. Figure 2 shows the monthly Cost of Gas Rider rates in place over the past 5 years for the four natural gas utilities in North Dakota, and Figure 3 is a comparison of average "all in" natural gas rates for various utilities in the upper midwest. In both graphs, NSP's costs rank very well relative to the respective utility comparison group.

Figure 2

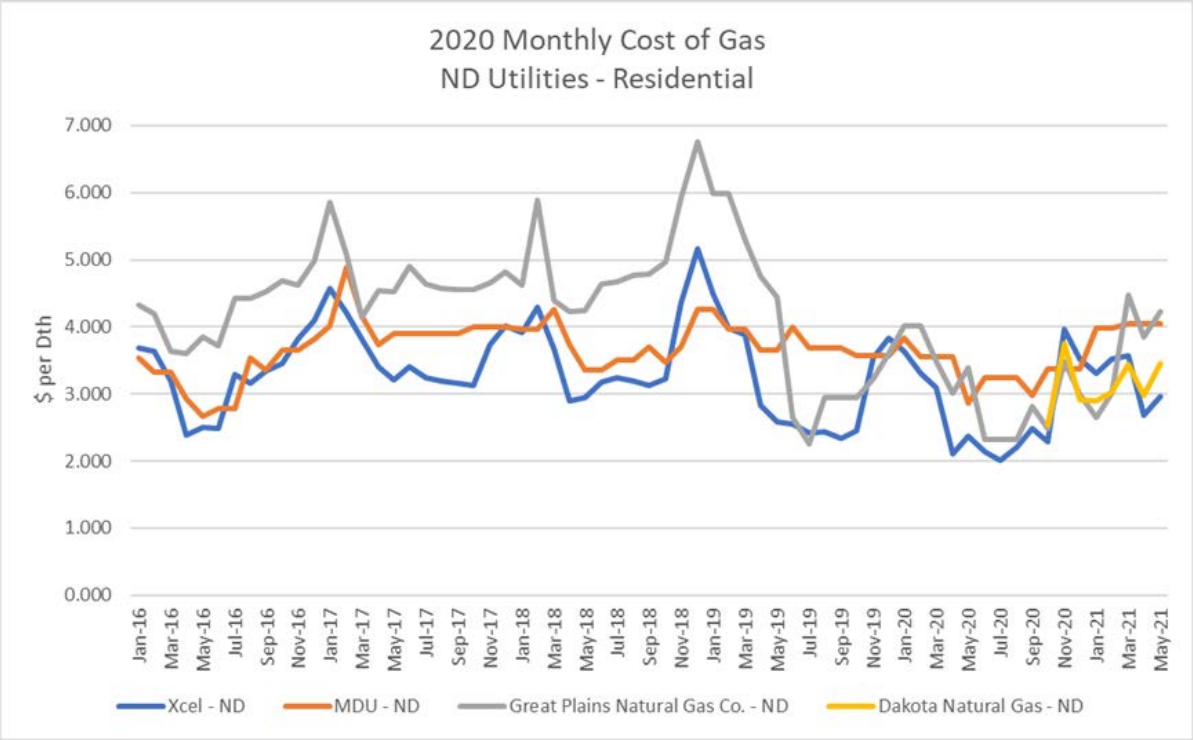
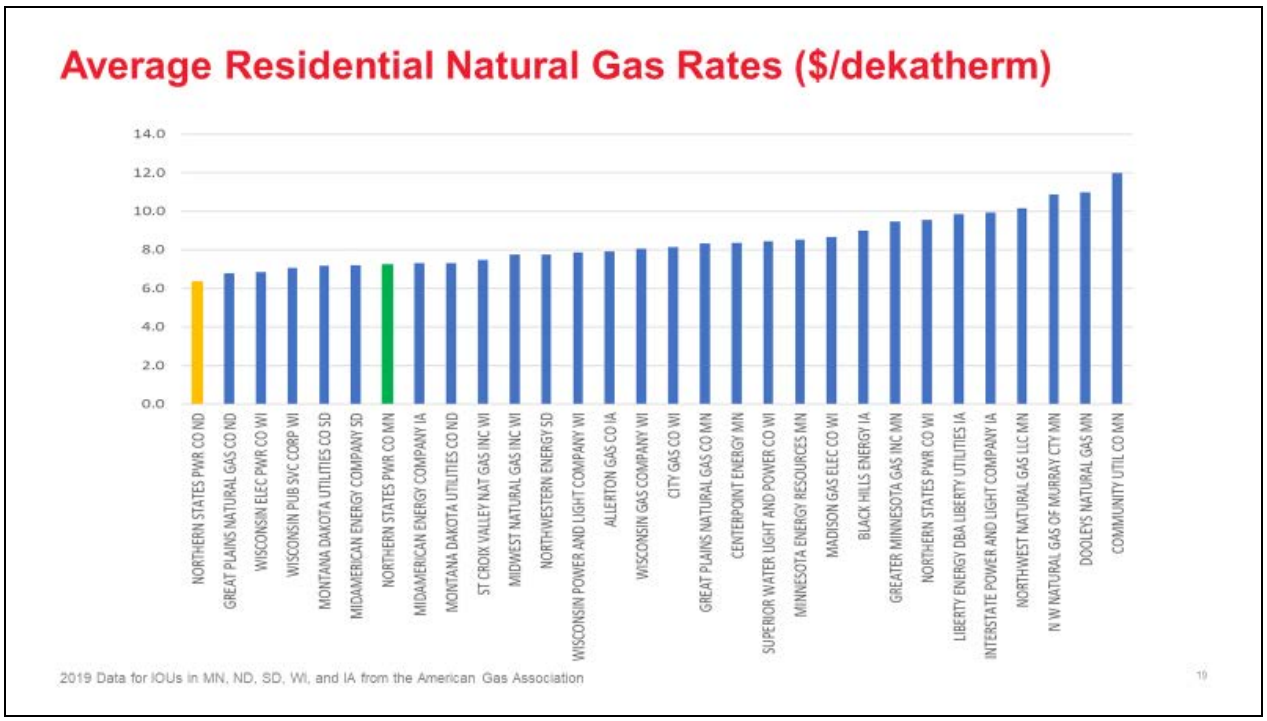


Figure 3



If you have any questions, please feel free to contact me at (701) 371-5256.

Sincerely,

DAVID H. SEDERQUIST
SENIOR REGULATORY CONSULTANT

c: Victor Schock