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VIA U. S. AND ELECTRONIC MAIL

Mr. Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission, Dept. 0408
600 East Blvd.
Bismarck, ND 58505

RE: RESPONSES TO INQUIRIES RELATED TO TRANSMISSION COSTS
CASE NO. PU-17-332 AND CASE NO. PU-17-365

Dear Mr. Nitschke:

This letter provides supplemental responses to two transmission-related questions that Commissioner Fedorchak asked during the Informal Hearings held in two separate dockets, described below.

Case No. PU-17-332 Maple River to Red River Transmission line CPCN

In our informal hearing on November 3rd regarding the Maple-River to Red River 115kV transmission Certificate of Public Convenience and Necessity (CPCN) case, Commissioner Fedorchak inquired as to who would have to pay for the additional costs of a new transmission line installed underground as requested or ordered by the local municipality – would the municipality, its NSP customers, or all customers on the NSP System?

Typically, the Company's transmission costs are treated as "system" costs and thus generally allocated to all of the states and customers served by our NSP System. However, if a municipality requests or orders us to underground a transmission line that we believe would be most economic and operationally effective if constructed as an overhead line, the Company's position is that the additional expenditures of undergrounding should be borne by the municipality. This is based on Part 5.3 *Special Facilities* of Section 6, *Rules and Regulations* in our North Dakota Electric Rate Book (NDPSC No. 2) which states:

"When requested by the customer, the Company will provide, if practicable, service through special facilities not normally provided under Section 5.1, *Standard Installation*. Common examples of special facilities are duplicate service facilities, special switching equipment, special service voltage, three-phase service where

single phase is adequate, excess capacity, capacity for intermittent equipment, trailer park distribution systems, underground installations to wood poles and other **special undergrounding and relocation or replacement of existing Company facilities**. Charges will be made for such service in accordance with this rule.

The customer will execute an agreement or service form pertaining to the installation, operation and maintenance of the facilities. Payments required will be made on a nonrefundable basis and may be required in advance of construction unless other arrangements are agreed to in writing by the Company. The facilities installed by the Company shall be the property of the Company. Any payment by a customer will not entitle the customer to any ownership interest or rights therein.

Payment for special facilities may be required by either of the following methods, or a combination of these methods, as prescribed by the Company:

- A. A single charge for the costs incurred or to be incurred by the Company due to such a special installation, or
- B. A monthly charge of one-twelfth of the Company's annual fixed cost, plus cost of maintenance to provide such a special installation. The monthly charge will be discontinued if the special requested facilities are removed or if the customer eventually qualifies for the originally requested special facilities."

Assuming there aren't any unusual circumstances (such as lack of buildable right-of-way for overhead construction, aviation restrictions, public safety concerns, etc.) that might require an underground installation, we would pursue payment from the municipality or, if necessary, any needed authority from the relevant commission to implement a surcharge or local rate to the customers benefitting from the non-standard construction or infrastructure.

That said, a state commission could still take the position, potentially, that the cost (or, more specifically, the given state's allocation of those costs) should be socialized in the company's base rates. In that case, other NSP System state commissions might react to the socializing of the additional expense of undergrounding a transmission line. They may make the case that the requesting municipality (or perhaps the state approving the socialization of costs in base rates) should pay for *all* of the incremental costs of the undergrounding (assuming, again, it is for aesthetic reasons) given that it was a discretionary decision and made at a local level.

In summary, Xcel Energy would assume that the incremental costs of requested and "above-standard" transmission line undergrounding should be borne by the requesting municipality or at least the Xcel Energy customers within it instead of all customers served by the NSP system. However, state commissions appear to have the ultimate authority to order a different treatment based on the specific factors of each project.

Case No. PU-17-365 2018 Transmission Cost Rider (TCR) Rate

In our informal hearing on November 29th regarding the Company's proposed 2018 TCR rate, Commissioner Fedorchak asked if the Company includes the costs of new transmission lines that support the build-out of wind generation facilities when it estimates the cost savings of those wind projects.

The Strategist modeling we conduct in connection with assessing the financial impacts of resource additions takes into account all capital and operating costs directly related to the selection of that particular resource, as well as some additional direct costs. For our recent wind proposals, these costs include (1) the initial capital costs associated with constructing the resources; (2) continuing capital and operating costs over the life of those resources; (3) costs associated with transmission network upgrades required by MISO to interconnect the resources; (4) congestion costs; and (5) a number of wind integration costs including MISO contingency reserves, MISO regulating reserves, MISO revenue sufficiency guarantee charges, coal cycling costs, and natural gas storage costs.

We do not include in these analyses costs for larger, regional transmission projects such as the Capx2020 group or other MISO Multi-Value Projects (MVP) that help connect new generation (including these wind projects) to load but also provide other important benefits to customers. We believe this approach makes sense for two principal reasons. First, these transmission projects were already underway or completed before we proposed either our 1,550 MW portfolio or Dakota Range. Second, these projects are generally intended to serve a variety of regional transmission needs, as determined by MISO, and are not solely attributable to moving power from any particular resource, group of resources, or utility.

The aim of our Strategist modeling is to quantify, on a present-value basis, the incremental financial consequences of a particular resource selection so that our resource decisions are informed by the benefits and costs expected to result directly from that decision. In other words, previously approved or in-progress projects (like the Capx2020 transmission lines or MVPs) are incorporated into our base case Strategist assumptions so that the consequences of a particular resource addition can be identified as an incremental change relative to that base case.

Even if a portion of the costs of the CapX2020 and MVP transmission projects are associated with and added to the wind projects, we conclude that there is still a significant net savings to customers. This is due largely to the magnitude of benefits we anticipate as result of both the 1,550 MW portfolio and Dakota Range, as well as the revenues our customers receive from other beneficiaries of these transmission projects. To illustrate, we can start with the average residential bill savings resulting from the lower cost wind-generated electricity – from our Strategist modeling we estimate this to be in the range of \$2.00 to \$2.50 per month. If we were to assume that a good portion – say one fourth – of the CapX2020 costs captured in the current North Dakota Transmission Cost Rider (TCR) could be solely attributed to the wind projects, these monthly savings would only be reduced by roughly 50¢. While it may not be realistic to try to parse out the proportion of a large regional transmission project attributed to wind development, we appreciate the commission’s question and offer this simple but intuitive assessment.

Lastly, it should be noted that our current assessments of the savings from wind generation are being calculated using historically low natural gas price forecasts, and our analysis does not really quantify the risk reduction of eliminating exposure to higher fuel prices on approximately 15-20 percent of the energy needs of the NSP System. In other words, if future natural gas prices ever spike or increase at higher rates than modeled, our wind generation will provide even more savings.

We hope this information has been helpful. If you have any further questions or comments, don't hesitate to contact me.

Sincerely,



David H. Sederquist
Sr. Regulatory and Financial Consultant