BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificates of Need for Four Large High Voltage Transmission Line Projects in Southwestern Minnesota	MPUC Docket No. E-002/CN-01-1958 OAH Docket No. 15-2500-14699-2

Prefiled Direct Testimony of B. Art Hughes, Ph. D.

On Behalf of Public Intervenors Network

April 30, 2002

Q: Please state your name, business address and for whom you appear.

A: My name is Bernard A. (Art) Hughes. My business address is 1903 B, David St, Austin, Texas 78705-5311. I am appearing on behalf of Public Intervenors Network.

Q: Please describe your qualifications for making this testimony, including your educational background and employment experience.

A: I hold B.S., M.S. and Ph.D. degrees in Electrical Engineering, Electric Power Major. I hold a B.S. in Electrical Engineering from the University of Manitoba, 1972; and the M.S. and Ph.D. from the University of Texas in 1976 and 1978. My work experience has focused on power systems planning, the development of EMS (Energy Management Systems) and DMS (distribution management systems) for power systems, and selected projects for the Electric Power Research Institute. My full resume is attached as Exhibit ____ BAH-1.

Q: Have you provided expert testimony in other transmission cases?

A: Yes, I was an expert witness in the hearing before the Wisconsin Public Service Commission regarding the application of Northern States Power Company and Dairyland Power Cooperative for the Chisago Electric Transmission Line Project, PSCW Docket No. 1515-CE-102 and 4220-CE-155. I also testified informally in the Public Hearings before the Minnesota Environmental Quality Board for the Chisago Project.

Q: What is the purpose of your testimony?

A: The purpose of this testimony is to present the Public Utilities Commission of Minnesota, in this hearing before the Office of Administrative Hearings, with an analysis of the technical and planning issues. The focus of the testimony centers on evaluating the modeling and analysis and assessing the relative merits and costs of Options 1 and 3.

Q: Please state what statutory guidelines and rules you are using to guide your engineering analysis in your direct testimony.

A: The criteria for issuance of a Certificate of Need are found in Minn. Stat. §216B.243 and Minn. R. 7849.0120. The cost recovery statute at issue in this proceeding is Minn. Stat. §216B.1645. Development of wind generation in Southwest Minnesota has been spurred by the wind mandate found in the "Prairie Island" bill, specifically Minn. Stat. §216B.2423.

Q: Why is the wind mandate important in this proceeding?

A: There are two components of the government mandate. First is the mandate for Xcel to construct or contract the remaining 400 MW of new wind power generation capacity in the Buffalo Ridge Area. Secondly, the state law provides that all transmission upgrade costs required to specifically support state mandated renewable generation, in this case total wind generation of 825MW, of which 400MW remains to be contracted and constructed, and biomass generation of 50MW, may be included in the rate base and receives advantageous treatment by allowing immediate recovery rather than recovery over an extended time.

Q: Have you reviewed Xcel's application?

A: Yes, I have. I have also selectively reviewed the Xcel Southwest Minnesota/Southeast South Dakota Electric Transmission Study, November 13, 2001; the March 25, 2002 Supplement to the Application regarding the 'underbuild;" the April 2, 2002, Supplement to the Application, in particular the cost changes; Lignite Vision 21 Report; MAPP Transmission map; and supporting study results and related documents.

Q: In your opinion, based upon your electrical engineering and planning experience, please summarize the primary issues.

A: First, it is my opinion that the costs necessary to correct preexisting deficiencies, for example created by merchant base or peak loaded generation, are not attributable to renewable generation and are therefore not eligible to be included in the rate base for cost recovery. It is my understanding that the 825 MW of wind generation capacity is comprised of the following components:

- 290 MW of existing installed nameplate capacity or 260 MW at the receiving 115kV substation transmission bus.
- 135 MW of existing planned nameplate capacity
- 400 MW of state mandated future wind generation nameplate capacity.

The wind capacity factor is for the Buffalo Ridge Area is assumed to be approximately 30% to 35% of nameplate rating in the winter and 25% to 30% of nameplate in the summer.

Second, it is my opinion that the Applicant's preference for Option 1 is not justified. It is my opinion that Option 3 is preferable to Option 1 to support and nurture wind generation in the Buffalo Ridge Area

Q: What does Xcel claim in its application?

A: The Applicant makes several claims:

Claim #1. That Options 1 and 3 are both viable solutions to meet the transmission needs of a total of 825 MW of wind generation in the Buffalo Ridge Area.

Claim #2. That Option 1 is the preferred solution because it is the cheaper of Options 1 and 3 given the information presented in the Application. (The Applicants, correctly in my opinion, initially eliminated all but Options 1 and 3.)

Claim #3. That all the costs associated with either Options 1 and 3, or any Option selected by the PUC are eligible under §216B.1645 to be recovered in the rate base.

Q: Summarize your assessment of the Applicant's claims.

A: My overall assessment of the Applicant's claims based upon my review of the documentation provided and my experience in the power industry is:

1. Claim #1 is true in that Options 1 and 3 are both viable solutions.

2. Claim #2 that Option 1 is the better or preferred solution is false in two respects:

   2.1. Option 1, after taking into account the April 2, 2002, cost corrections provided by the Applicant and the correction of an error in the analysis of the MW losses and thus the assigned costs, is probably more costly than Option 3.

   2.2. Option 3 proves a better engineering solution than Option 1 for meeting the specific needs of wind power generation in the Buffalo Ridge.

3. Claim #3 is false in that many of the mitigation-related costs for necessary fixes before additional wind generation capacity is added appear not to be eligible for inclusion in the rate base. They are not directly attributable to mandated generation, nor are those costs for "excess capacity for wind beyond the mandate" which also is not attributable to the renewable mandate. Also problematic is the already operating 290 MW nameplate rating which is currently being transmitted without upgrades. Only transmission and upgrades directly associated with and necessary for transmission of mandated renewables generation is eligible for rate treatment provided by §216B.1645.

To further clarify, the types of needs for transmission may conceptually be thought of as shown in the following diagram where:

Mitigates preexisting problems	Supports the 400 MW mandate	Provides excess capacity

The terms used are defined as follows:

- ***Preexisting.*** Accounting for the costs of preexisting problems requiring mitigation is conceptually clear, but analytically complex. Specifically, what is clear is that preexisting conditions, or rather the cost of correcting them, are not eligible to be included in the rate base because they are not attributable to renewable generation. The mitigation and the costs would be necessary for any type of generation, for example, if a coal plant were built near Chanarambie rather than wind. The analytic challenge is to decide which of the mitigation efforts are preexisting conditions. Additional studies may be required to finally determine eligibility for some of the mitigation costs, but that task will be for the separate miscellaneous rate docket, E-002/M-02-474. In this proceeding, it need only be established that there are preexisting conditions which proposed fixes in the Application mitigate.

- ***The Mandate***. Transmission upgrades to support the additional 400MW wind mandate requires little discussion as the mandate is clear. Transmission support for the presently planned but not installed 135 MW may also be eligible for inclusion in the rate base and associated cost recovery.

- ***Excess Capacity.*** Any excess capacity should be reserved for additional wind or other renewable generation as this supports the spirit of the state mandate to nurture renewable energy and related industries in Minnesota. The costs of transmission capacity in excess of the mandate should not be recoverable under §216B.1645 as it is not capacity necessary for the mandated renewables at this time.

I use the word mitigation to define the act of correcting a limit violation that must be alleviated. Mitigation costs are the costs associated with the upgrade construction necessary to alleviate these limit violations. Both the Application and this testimony has focused on the corrective construction and associated costs rather than limit violations themselves, since in this case the limit violations are only of interest in as much as they need to be alleviated. Mitigating or alleviating these limit violations is of primary interest since it is the construction and the construction costs that are central to the application together with whether these costs should be allocated to the rate base for cost recovery.

Q: Are there other issues that should be raised concerning accounting for the cost of transmission upgrades in this application?

A: Yes, there are two additional points that need to be addressed:

First, the Option that is selected and constructed should probably be augmented to include a complementary 34.5 kV system, sometimes called a collector or an under-build system, as this will nurture future wind generation as intended by reducing the initial capital costs of connecting generation to the transmission.

Secondly, the final resolution of what goes in the rate base should be decided at the appropriate rate hearings, and thus the responsibilities here are limited to framing the issues, raising the questions and presenting the facts to the extent that the available studies support.

General Analysis

Q: Please outline the major areas of concern with the Application that you have identified and thus the areas where your analysis and testimony focused.

A: The areas of concern that I have with the Application fall into two basic areas, specifically the testimony shows that:

1. The stated preference by the Applicants for Option 1 over Option 3 is not supported by general power system engineering concepts or by the specific budgetary or technical facts.

2. Not all the costs appear eligible to be included in the rate base for cost recovery under the mandates because they are not necessary to support mandated renewable generation, but are rather required by preexisting conditions.

Q: Define the errors in the construction budgetary numbers used to justify Applicant's preference for Option 1 over Option 3.

A: My first concern is that the construction numbers are changing such that I am not sure what the correct numbers are.

My second concern is that the Application and associated preference for Option 1 is based on preliminary and apparently wrong budget numbers. At present the budget numbers appear to range from approximately equality for Options 1 and 3 to Option 3 being lower cost by many millions of dollars, perhaps by as much as 10 to 20 million dollars.

As a special note, such material, widespread changes in the budgetary numbers is disconcerting, and raises questions of the general quality of the Application as a basis for decision making. The timing is also suspect, because the changes were not revealed until after Intervenors' time to request information had passed. Clarification has thus been difficult.

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Q: Describe the problems in the Application in calculating MW losses, and assigning MW loss related costs.

A: The Applicants made a major error in the loss cost analysis, and performed some sloppy analysis with the result that the assignment of MW loss related costs and the assessment was seriously distorted. Specifically:

1. The Applicant's assumption that most losses occur at off peak load for wind generation, and other non-peaking generation, is true. However, it is not correct to assume that all off peak load conditions directly correlate with high transfer/export conditions. That is a fundamental error; these two independent and complex variables must be treated separately in the analysis.

2. The Applicant's use of a 30% loss correction factor to reduce the calculated losses is sloppy analysis; they should have for clarity assumed the output of the wind generators is on average on 30% (or similar approximation) of nameplate rating. Average power, not the maximum capacity, creates MW losses.

3. Note, the major difference in the transfers between peak load and off peak load, defined as 70% of peak, is that the NDEX transfer, or export, is increased 600 MW for the off peak load condition. This 600 MW dominates the mandated 120 MW of mandated wind power, the 400MW correctly adjusted for its 30% generation factor, and it indicates one of two things:

3.1. Either the assumption by the Applicant to use firm transfer numbers at peak loads and the high transfer condition of the MAPP studies, which is actually the maximum transfer limits as described in the Appendix 2 Study, Page 5, is not justified and indeed has materially distorted the analysis for this Application.

3.2 There is 600 MW of North Dakota generation that needs transmission to eastern markets that must to be accounted for. If this generation is available for export at peak load, and if there is no transmission for it at such times, then it would appear to be "stranded" in some way and transmission capacity needs to be provided. If, on the other hand, it is only available at non-peak load times, its impact upon the transmission system and the transmission system losses must be separately accounted for and not "bundled" in with the 400 MW wind generation increase, reduced to 120MW for 30%, for intermittence, with the wind generation picking up all the transmission and transmission loss costs. Specifically, as will be discussed later, it must be first ensured that there is transmission capacity for the assumed ND export and then the 400 MW times (0.3) =120 MW can be evaluated incrementally.

In summary, these faulty assumptions and errors in modeling need to be corrected and new MW loss studies done. It is absurd to make decisions based upon the existing modeling and calculations, as evidenced by the Applicant's statements on the bottom of page 18 of the Appendix 2 Study "that losses differences for the transmission options (for 400 MW of wind generation) could be as high as 27%" of the 400 MW. This leaves essentially no power, just 3%, to get to market.

Q: Outline what impact corrections of the previous question in the Applications would have in the comparative loses and associated loss costs between options 1 and option 3.

A: New studies are required to provide precise answers based upon corrections identified in the previous response. This response is an approximation, estimates based upon engineering judgment. Specifically, Table 5 (Appendix 2, Study Table 5, Page 17) shows Option 3 having lower MW losses at peak load with identified power transfers than does Option 1. Recall the major change in the high transfers for 70% peak load is to add the 600 MW for ND, and this 600 MW dominates the average wind generation mandate of 120 MW wind generation by a factor of 5. Moreover, the wind power generation does not change between peak load conditions where Option 3 has fewer MW losses than Option 1. Therefore, we can state subject to verification with new studies:

1. The dominant factor in the increase of losses at off peak (70%) load appears to be primarily due to the 600 MW change in ND transfers.

2. The peak load characteristics of lower Option 3 losses as compared to Option 1 would probably carry over to lower load conditions if it were not for the 600 MW of increased transfer from ND or if the transmission system was strengthened to support the high transfers before considering Option 1 and Option 3 upgrades for the wind energy.

We can conclude, subject to verification by corrected studies, that any differences in MW losses between Options 1 and 3 would be small, would probably favor Option 3, but could favor either option. It should be noted that the argument that the 600 MW transfer change from ND effects both Options 1 and 3 equally and is therefore a wash it not valid. It is not valid because Option 1 with its higher voltage construction and the electrical location of this new construction is surely more suited for supporting transfers of ND power than is Option 3. Option 3, on the other hand, appears to be more suitable for nurturing wind power generation at Buffalo Ridge.)

Q: Define extra high voltage (EHV) transmission and high voltage transmission systems.

A: Transmission systems such as Xcel's may be conceptually thought of as comprising of two interacting parts; the extra high voltage grid made up of transmission lines and associated stations at voltages 230 kV up through 345 kV and 500 kV to 765 kV, and the high voltage grid of voltage levels from 115 kV, 138 kV, 161 kV to 230 kV, and of course the subtransmission grids of 69kV and below. The exact dividing line between the extra high voltage, high voltage, and the sub transmission grids is not vigorously defined.

Q: Discuss how the extra high voltage grid and the high voltage transmission grids interact to support the transfer of electrical power.

A: The interconnected extra-high and high voltage grid act in many ways like a highway system, with one fundamental exception. The flow of power, as opposed to traffic on the highway system, does not automatically adjust when limits are reached on any one line. The weakest link thus sets the limit for the overall transfer of power on the grid until this weakest link is upgraded or the weakness is mitigated in some way, at which point another link becomes “the weakest link.” It is also a characteristic of electric power systems that the high voltage transmission lines generally reach their limits before the electrically parallel extra high voltage lines reach their limits. .

Q: Define the two conceptual ways to increase power transfer capacity for an interconnected extra high voltage and underlying high voltage transmission grid, and outline which is typically the better approach.

A: The capacity to transmit power may be accomplished by strengthening the extra high voltage transmission system and thus reducing the loading or reflected stress on the high voltage transmission system and/or by strengthening the high voltage transmission to support the loading stress and thus enable existing extra high voltage transmission capability to be utilized more effectively. One approach is not universally better than the other, it depends on the nature of the existing extra high voltage and high voltage transmission grids and the existing and projected new needs. It is the complementary nature and strengths of the extra high voltage and high voltage transmission grids that is required for overall effectiveness and efficiency. Using the analogy with the highway system, expressways, country roads and city streets are all appropriate in their place. The question that must be addressed is which option is the more appropriate infrastructure configuration for supporting the projected needs in each case.

Q: Outline the nature of the stress on the electrical grid in the Buffalo Ridge Area and in the electrical corridors between the Buffalo Ridge Area and the major electrical markets to the east.

A: The power system grid in the South West Minnesota, or Buffalo Ridge area, particularly Nobles, Lyon, Pipestone and Murray counties, ignoring local load serving needs, is driven primarily by two needs -- supporting the export of wind generated from Buffalo Ridge and other local generation, and the transfer of power form North and South Dakotas eastward to market. These two needs stress the extra high and high voltage transmission grid in somewhat different ways. For example, large central station generation located far from load centers is typically best served with extra high voltage interconnected lines between the generation and the load centers with limited, and selectively placed, connections to the lower underlying transmission system. This minimizes the likelihood that limits on the lower voltage transmission system will effectively limit flows on the extra high voltage lines. The wind generation, because it is widely dispersed over a large, multiple county area, requires a number of connecting points between the projected 34.5 kV collector system and the higher voltage lines. MW losses become excessive and maintaining voltage becomes problematic if 34.5 kV lines are not kept relatively short. The net effect is that a strong high voltage transmission system is highly desirable for providing a transmission outlet for wind generation, both to contain costs, and provide an electrically supportive environment for the 34.5 kV collector system. Just how high the high voltage transmission system should be in this case is at issue.

Q: Does Option 1, which is centered on a 345 kV line, inherently provide more export capacity for planned and possible future wind power on Buffalo Ridge than Option 3 that is centered on 115 kV and 161 kV construction?

A: No, definitely not. By the Applicants own analysis both Options support at least the necessary total 825 MW of wind generation. It is a fallacy to directly correlate higher voltage construction of one line with a "stronger system" or more transfer capability for the integrated extra high voltage and high voltage transmission grid. This fact can be readily seen by the Applicants own studies where even with the 345 kV line in the model for Option 1 and the 115 kV and 161kV lines in the model for Option 3, there were still many other limiting factors that required mitigation, normally some form of construction or a system upgrade.

Q: Is it possible to determine whether Option 1, or Option 3 best strengthens the integrated system?

A: No, it is not possible to determine which option best strengthens the system without studies many of which have not been performed, although by considering the types of problems that may arise some general qualitative assessment possible. For example:

1. Stability. No stability studies have been performed but from the static studies performed by the Applicants and the nature of the construction changes made the following appears to be true:

    1.1. Transient stability. Both Options would appear to satisfy the system stability needs, as would be expected from the nature of the changes made; however, only detailed studies that the Applicants state have not been performed can confirm this. While the application implies that perhaps Option 1 with its higher voltage design may perform better, there is no basis for such a conclusion until verifying studies are performed.

    1.2. Voltage stability. Both Options 1 and 3 with their relatively low VAR compensation requirements appear to pass muster, as shown by the applicant's static studies.

2. Reliability.

    While studies have not been performed, it would appear from the nature of the changes that both Options 1 and 3 are satisfactory. However, Option 3 may have a qualitative edge here in the narrowly defined reliability to ship the mandated wind power generation under abnormal system conditions since it will likely be more closely connected to and supportive of the 34.5 kV collector system. Optimally they should have an integrated plan.

3. Short circuit currents occur during fault conditions and tend to be a problem where there is large generation electrically close. Short circuit currents are surely not a problem for Option 3 given the nature of the construction changes that are primarily lower voltages. There is more risk of excessive short circuit currents during fault conditions with Option 1, although studies could be readily performed to check. Excessively high short circuit currents tend to cause technical and equipment cost problems in the lower voltage systems.

Q: Explain what if any benefit the much larger thermal rating capacity of the 345kV line, which at 1800MW in the MAPP plan is much in excess of any foreseeable wind power needs, actually provides now or potentially in the future. Exhibit ___, BAH-2, MAPP map, Transmission chart, lower left;[1] Exhibit ___, BAH-2A, Midwest ISO Tariff, p. 190.[2]

A: There are a number of aspects to this response each of which is necessary. Specifically:

1. It is not possible from the study results available to determine how much of this large 345 kV line capacity is actually needed by wind generation, or even will actually be used by the mandated total of 825 MW of wind generation. This information is buried in the study results since the Applicants commingled addressing preexisting limit violations and supporting the mandated wind power generation.

2. There are material, very real, costs associated with building a large size, higher voltage, line.

3. As mentioned previously, Option 1 with its 345 kV core construction does not add any additional wind power export capacity as compared to Option 3. The active limits on system capacity is not the new construction but limitations of the existing facilities. This s normal. By their own calculations (the TLTG tables) the Applicants show that both Option 1 and Option 3 support the total of 825 MW of wind generation. Indeed the TLTG tables show than both Options can support increased wind power generation far beyond the total 825 MW mandated with some incremental construction to mitigate limit violations. There are no benefits to super sizing Option 1 construction as compared to the benefits of Option 3 for the projected 400 MW of wind generation or indeed increasing this generation by 50% in the future.

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[1] The MAPP map may be found electronically at www.mapp.org, go to Library, to 10 Year Transmission Plan.
[2] The Midwest ISO Tariff may be found in its entirety at www.midwestiso.org.

4. The only possible benefit, and it has not been shown that such benefits even exist, of the Option 1, 345 kV Plan compared to Option 3 would appear to be that should it be decided in the future to build transmission to support major new Dakota coal fired large generation plants the cost of needed transmission upgrades to support this may be reduced. The February 6, 2001,Lignite Vision 21 Project Report considers 7 alternative sites for a possible 1000 MW of new ND generation and associated transmission upgrades for exporting the power. Exhibit ___, BAH-3, Lignite Vision 21.

5. Possible future benefits, if they exist, are nice for the benefactor, but they do not justify the apparent multi million cost premium of Option 1 over Option 3. Such possible future benefits do not justify including such costs in the rate base as necessary for transmission of renewable generation, as part of the renewable energy mandate. Subsidizing planned future coal generation would appear to directly conflict the intent of the Minnesota renewables mandate.

In summary, within the context of the wind generation mandate, and deciding on transmission Options, there is no justification for including any possible future benefits of the large capacity of the Option 1, 345 kV constructions.

Q: Define contingency, single contingency analysis, and the n-1 reliability standard.

A: A contingency is defined as a single event that results in the loss of one specific component such as a transmission line, or generator. Some single events like the loss of a tower will take out both lines for a double circuit.

Single contingency analysis is defined as analyzing "what if" conditions given any one event or loss of component occurs.

A system is defined as first contingency, or n-1, reliable or secure if it can withstand any single contingency without causing unacceptable system limit violations. This "n-1 standard" is the standard by which the industry tends to conduct transmission planning. Exhibit ___- BAH-4, NERC Planning Standards, I. System Adequacy and Security, Table 1, p. 13-14; III. System Protection and Control, A,S2., p. 47-49.[3]

Q: Summarize whether Option 1 or Option 3, in your professional opinion, best meets the overall needs claimed by the utility for export capacity for the remaining mandated wind generation and for potential future wind generation in the Buffalo Ridge Area.

A: As a reference for this response, let us consider the situation around Eau Claire, Wisconsin (especially to the northwest). There is a 345 kV transmission line from the King plant near the border in Minnesota, with a switching station at Eau Claire, and then the 345 kV line continues on to Weston farther east. This 345 kV line was installed decades ago and is a major route for shipping bulk power from Minnesota to Milwaukee and Chicago area markets. There was for many years a relatively weak 115 kV, 161 kV transmission system in the Eau Claire area and:

1. During some heavy transfer periods, the flows on the 345 kV line were sometimes restricted by the limit violations that would occur on the lower voltage transmission system should the King to Eau Claire segment of the 345 kV be lost.

2. The situation was considered so problematic that for some of this time, that system operations automatically switched out (transfer tripped) the 345 kV line segment from Eau Claire to Weston upon loss of the King 345 kV line segment to minimize the limit violations in the lower voltage transmission network. (Note there was also an operating guide is in place limiting transfer capacity to alleviate reclosing problems due to phase angle separation during some periods of time.)
3. In recent years utilities have upgraded and strengthened the underlying 115 kV, 161 kV transmission grid.

[3] The two page table and three relevant pages of this 77 page document have been provided as an Exhibit. The entire document is available at www.nerc.com/pub/sys/all_updl/pc/pss/ps9709.pdf.

Comparing the Eau Claire and Buffalo Ridge areas, and they are certainly not identical, we can state the following for the Buffalo Ridge area:

1. There are extra high voltage power lines in the area that supports transfer bulk power flows.

2. The high voltage transmission network is relatively weak as shown by the number of mitigation driven changes required by the Applicant's studies.

3. In both in normal operation, and even more so in some contingency situations, the lower voltage transmission lines will likely be quite heavily loaded. This could easily put the wind generators in direct competition with the large central station generators from the Dakotas and points west. In fact the wind generators will be at a disadvantage since the lower voltage transmission lines, to which wind generators are typically connected, tend to become stressed and reach their limits first.

4. Additional connection points to the extra high voltage grid to provide access for the exporting wind power, as is likely over an extended timeframe for Option 1 is a two-edged sword and could exacerbate the problem because loss of a shorter extra high voltage line segment between these access points could stress the underlying transmission to an extent that export of wind power generation may be impeded.

In summary, Option 1 may tend to put the mandated and future wind power generation into a more difficult position competing for access with existing and possible future Dakota large generators than would Option 3. Option 3 tends to reduce the likelihood and the severity of such competition by (beginning to) systematically strengthening the lower (HV) transmission system in the area. It may indeed be that Option 3 is thus the better option for those who plan to generate wind power in the Buffalo Ridge Area.

Eligible Versus Ineligible Costs

Q: What is the purpose of this section?

A: The purpose of this section is to frame the issues, and selectively provide examples from the available studies, to assess which of the construction costs are eligible and which are ineligible to be included in the rate base for cost recovery.

Q: Do you agree with the choice of the type of studies performed by the Applicants?

A: Yes, although some stability, reliability and short circuit studies would have been useful., The study tools used are very credible in the industry. My concern is more with the modeling than the studies.

Q: What are your concerns related to the modeling?

A: My concerns with the modeling center on the underlying assumptions of transfer levels and associated equipment included in the base model, and some lack of organizing the studies to focus on the principle questions to be decided on.

Q: What are your concerns related to a determination of those costs eligible for rate recovery as Applicant requests?

A: My concerns fall into the two general areas of preexisting deficiencies and how costs are allocated including:

1. Preexisting deficiencies: The inclusion of costs that are due to, or appear to be due to, preexisting problems, that is, problems that are existing before the need to support the 400 MW of wind power generation and which are not attributable to wind or renewable generation transmission needs.

2. Costs related to wind mandate: The general way costs are allocated entirely to the mandated wind generation transmission need. Specifically, the following issues need to be considered and the ramifications evaluated:

2.1. The 600 MW of ND generation discussed previously:

2.1.1. If real, it is in need of transmission support, and this needed transmission support should be planned for and any upgrades included in the base study for the mandated wind power.

2.1.2. If it is not real but created due the modeling assumptions used by the Applicants then the assumptions should be changed and the studies redone since it is distorting the studies

2.2. The Applicants state that they assumed the base system includes construction completed by the summer of 2001 (Page 5 of the Appendix 2 Study). Then what methodology for allocation of costs is being used?

2.2.1. That the first to go in service or to need transmission facilities should pay for it all? If this is the case, then in-service dates for other projected new generation should be ascertained and appropriate studies for associated transmission and cost allocation performed.

2.2.2. The first party that plans for transmission upgrades should pay for it all? If this is the case then any upgrades that are presently planned should be included in the base study for the 400 MW of wind power transmission.

2.2.3. Some allocation of costs based upon perceived benefits to new and existing users of the grid?

3. Excess capacity: There are costs associated with the proposed Options that appear to be for improvements that provide individual transmission line capacity in excess of 1,000MW or more, which is beyond the remaining generation mandated, whether 400MW, or 535MW. If these costs are for improvements not attributable to the renewables mandate, but for improvements providing capacity beyond that mandate, they should be categorized separately from those costs necessary for renewables transmission.

In summary, the cost allocation is a complex issue that needs analysis beyond what we can provide based upon the information available, and should be addressed separately in the Miscellaneous Docket E-002/M-02.474. The apportionment of costs is an important issue because the general perception and possible reality of the competitiveness of wind generation is affected.

Q: State the underlying assumptions made in your determination of what constitutes preexisting limit violation conditions, or what associated preexisting costs are not associated with the mandated wind power generation and are ineligible to inclusion in the rate base for cost recovery.

A: The primary study for determining pre-existing limit violation conditions is found in "C-i, ACCC Outputs, Existing System, summer 2001, off peak – 1999 MAPP series.

Q: Why are the C-i study conditions and associated studies the primary basis for determining pre-existing violations?

A: The C-i studies are based upon the peak transfers especially the 1950 MW ND export, and include only the presently existing wind power, and have no updated transmission. These are critical initial conditions to get correct for a base line from which to evaluate the system and associated cost allocation.

Q: Please state what is important in the C-i study results; that is, what anyone reading the results should look for.

A: What is relevant, what is extremely important, in the C-i study results are the overloads or limit violations.

Q: Why are the limit violations for the C-i studies important here?

A: Because the limit violations are pre-existing with respect to the mandated 400 MW of wind generation (and indeed for the 135 MW of planned but not installed wind generation also), that is, the conditions exist even before the additional remaining wind mandated generation is included in the model, and thus the associated costs are not eligible for inclusion in the rate base and associated cost recovery.

Q: How should the applicants reorganize their studies to correctly account for these pre-existing conditions?

A: The applicants should proceed with their studies in a sequence such as the following:

1. Step one. Determine all preexisting limit violation conditions as per studies C-i.

2. Step two. Develop construction plans for correcting all these preexisting conditions, and assign the associated construction and MW loss costs to the appropriate parties causing the violations. This scenario assumes several things:

    2.1. We are assuming that the first party that requires infrastructure improvements to facilitate that infrastructure must pay for the needed improvement. While we are making no statement about who should pay for the construction necessary to reach the new base, C-i-Corrected,[4] we are stating categorically that the wind power mandate process should not pay for these corrections. The 400 MW wind power mandate had no part, by definition, in creating the need for this transmission construction.

3. Step three. The updated system with all the pre-existing problems corrected should then be used as the base for the mandated wind power studies. This is the base C-i-Corrected.

4. Step four. Perform the 400 MW wind power generation mandate studies using the C-i-Corrected base and determine what transmission construction is needed, the incremental MW losses and the associated costs. These costs are eligible for inclusion in the rate base and associated investment recovery. There are some observations that should be made here:

4.1 The 135 MW of wind generation that is not presently in service, as assumed by the study, and which is not part of the 400 MW of mandated wind generation, needs to be accounted for. If this 135 MW is eligible for inclusion in the rate base then it should be included with the 400 MW studies as well. If it is not eligible for inclusion in the rate base, then it is pre-existing and its effects on the transmission needs and costs should be included in the new base C-i-Corrected.

4.2 The wind generation capacity factor of 0.3 (or whatever factor is selected) should be used in all MW loss calculations for wind generation, but not when considering transmission line flow and similar limits because for the purpose of modeling these cases, generation will at times be at full nameplate capacity.

[4] In the expression C-i-Corrected, "corrected" means necessary new construction has been added to the new base to remove all pre-existing limit violations. In the C-i base, the stress exists, such as the assumed high MW transfers, but the necessary transmission in not included.

4.3 The wind generation nameplate rating in the studies, here 825 MW, should be reduced by the projected losses within the 34.5 kV collector system as these losses place no demands on the transmission system. For our purposes here, we have assumed that the 400 MW mandate is nameplate rating.

Finally there is a possible step five. Once the construction and associated costs for both the corrected base case, C-i-Corrected, and the wind generation mandate have been determined sequentially, as outlined previously, a post analysis optimization phase should be performed to assess what if any improvements in the solution and associated cost reductions are possible by “integrating” the two sets of construction changes. Any reduction in costs can then be allocated between the parties paying for the base case, C-i-Corrected, corrections and to the wind mandate rate base inclusion cost recovery in some proportional or otherwise equitable way.

Q: What specific correlation should be expected between the limit violations found in the Applicants base (C-i) model based studies and the common or separate construction items or components of Options 1 and 3?

A: A one on one correlation should not be expected since Options 1 and 3 address the cumulative needs of the pre-existing violations and the needs caused by the mandated wind generation.

Q: What information do the limit violations in the Applicant’s base (C-i) studies actually provide?

A: Not much beyond the fact that they exist, that are pre-existing, that they are material and require mitigation, that by definition they are not caused by the mandated wind power generation and are not needed to fulfill the mandate, and the associated costs to correct these problems should not be deemed eligible for rate recovery.

Q: Briefly describe selected preexisting limit violations that exist in the base (C-i) studies and comment how by their nature they could effect the development of Options 1 and 3. .

A: All preexisting limit violations increase the construction costs of Options 1 and 3 when the cost to alleviate these limit violations is, incorrectly, included. Moreover, the very nature of these preexisting violations appears to be affecting the nature of the solution options. For example, there is a group of preexisting limit violations in the Minnesota Valley, Granite Falls, Panther, Franklin electrical area (base case C-i), with MW flows generally from west to east. Strengthening the more southern electrical loop from Watertown, through Sioux Falls, and Lakefield is one natural way to address these preexisting violations. The core components of Option 1 do essentially that. Indeed, it would appear that the very nature of Option 1 is driven more by the preexisting conditions more than by the needs of the mandated 400 MW of wind generation.

Option 3, on the other hand, is centered on strengthening (or actually beginning to) the 115 kV system that may in time become an effective overlay grid supporting the underlying 34.5 kV collector system. The possibility for the Option 3, 115 kV solution, together with some 69 kV, to evolve over an extended period as the wind generation needs evolve appears to quite good.

What would the total solution look like if the solutions were developed sequentially, with the preexisting conditions being addressed first and then the transmission for the wind generation mandate added? Without studies I can only speculate, but in my opinion it would likely take a form such as:

1. Many of the “outlying” construction changes that are electrically quite far removed would tend to remain the same.

2. The core 345 kV components of Option 1 may indeed be included in the construction necessary to fix the preexisting conditions although there may be some changes.

3. The core 115 kV components of Option 3 would quite likely be recognizable in the upgrades to support the mandated wind generation if the needs of the collector system are factored into the decision process. That is if the transmission and the underlying collector system were panned in a comprehensive, integrated manner.

In summary, commingling the preexisting limit violations with the transmission requirements for wind generation are not only grossly inflating the budgetary numbers for wind generation transmission, but may also be distorting the very nature of the solution.

Q: Briefly outline the type of studies performed by the Applicants in, for example, their studies of the base or C-i model.

A: The three primary analysis tools used by the Applicants are part of an integrated analysis package and they need to be understood as parts of an integrated approach. Specifically:

1. ACCC (AC Contingency Checking) checks what security limits are violated as it sequentially removes individual system components, particularly major lines and generators. Using the base case (C-i), or models for Options 1, 3, etc., it looks for limit violations. If there are no limit violations, it means that the system is operationally n-1 secure, that it continues to function if an element is removed.

2. TLTG (Transfer Limit Table Generator) performs ACCC like analysis for a selected transfer between two appropriately selected generators, or more correctly, points on the grid. Then it increases slightly by increments the selected transfer capacity and performs the studies again, repeatedly, until some appropriate stopping criteria is met, such as a desired increase in generation capacity. Construction updates to correct each limit violation are added sequentially. The MW transfers of interest in this case are between Buffalo Ridge generation area and the Twin City load area. Increasing generation in one area and decreasing it the other incrementally step-by-step implicitly makes the transfer

adjustments. A primary purpose of this analysis is to assess and identify the limiting components to new generation and thus MW transfers and what the associated transfer limits are. To facilitate analysis the output is organized into tables – hence the acronym TLTG.

3. Power Flow analysis is more rigorous than either the ACCC or TLTG analysis both of which selectively use appropriate approximations for computational efficiency, and is thus used for example to selectively confirm ACCC and TLTG results. Power Flow analysis models the non-linearity of the power system model, and hence the power flow results provide a reliable estimate of the system state such as line flow and bus voltages. Voltages in particular are sensitive to non-linear effects and thus more often require power flow, as opposed to ACCC and TLTG, analysis.

In summary, I have no concern with the analysis tools used by the Applicants. As stated earlier, my very real concern is with the inappropriate assumptions in the models and thus the distorted even incorrect results.

34.5 kV Collector System

Q: What is the purpose of this section?

A: The purpose of this section is to briefly assess selected requirements and other considerations of the 34.5 kV system that may be effected by or effect the decision of whether Option 3 or Option 1 is preferable.

Q: Define the terms “underbuild” and “collector” system.

A: The term collector system is used to describe an electrical network that supports the grouping of generation from a number of generators for transfer to market. The expression “under-build” is used to describe the construction of a low voltage line on the same poles as a higher voltage line. The lower voltage line is normally positioned under the higher voltage one, literally built under, hence the name “under-build”. An example of this can be found in the Buffalo Ridge Transmission Plan, which is similar to Xcel’s Option 3 with an “underbuild” for collection of wind generation and integration into the transmission grid. Exhibit ___ BAH-5, Buffalo Ridge Transmission Plan.[5]

Q: Compare the budgetary costs of a collector system for the 400 MW of mandated wind power with the difference in costs between Option 3 and Option 1.

A: Based on the Applicants numbers a collector system costs $50 to a $100 per kW. Thus a collector system for the 400 MW wind generation mandate would cost $20 to $40 million. Based upon the updated construction budget numbers and correction in the calculation of loss costs, it would appear that Option 3 might be sufficiently cheaper than Option 1 to fund, at the lower end of the estimate, the needed collector system. If so the comparison should really be based upon Option 3 with a collector system versus Option 1 without a collector system. Whatever the comparative costs of Options 1 and 3 finally turn out to be, it is certainly clear that the cost of including the collector system in the application is far less that the cost of fixing preexisting violations. Thus budget issues should not restrict inclusion of the collector system in the Application and the development of an integrated transmission upgrade and collector plan.

Q: State why you feel that the lower end of range of the Applicant’s estimate (of $50 to a $100 per kW) is probably more reasonable than the higher end of the range.

A: First let me state that no final estimates can be made until more information is available and thorough engineering work has been completed. Thus, I phrase my response in a series of example questions that have the potential to materially reduce the Applicants cost estimates, and thus need to considered. But first consider two underlying issues that

[5] The Buffalo Ridge Transmission Plan is available electronically at http://www.me3.org/issues/transmission/publicenergy.pdf

relate directly to the nature of wind generation that underpin my thinking that cost reductions are possible by more closely matching the solution with the nature of the problem:

1. Wind has a capacity factor that I have assumed to be 30% for Buffalo Ridge (the analysis is not depended on the exact number), but what is the profile of the wind generation /wind (leaving aside the exact relationship between these two factors which may be quite complex)? To show that this is an important point let us consider two alternatives that are in many ways end cases:

    1.1. Profile one:
        1.1.1. 90% of the time the wind generators produce 1/3 of their nameplate rating (calculations are approximate).
        1.1.2. 10% of the time there is no wind or generation. (Routine maintenance may be done in this time?)
    1.2. Profile two:
        1.2.1. 30% the time the generators produce 100% of their rating.
        1.2.2. 70% of the time the generators product nothing.

2. Wind generation has an effective cost due to the loss of (34.5 kV) feeder capacity that may be quite different to customers being supplied power from a similar feeder. Thus consideration of reliability and the trade off between reliability and cost may also be quite different. For example, the infrequent inability to generate at peak load, or at all for very a short period, due to feeder limitations may be less of a concern than losing power to a customer.

Taking the previous two points as a base:

1. Would not the nature of the terrain tend to group wind generators, along ridge lines for example, thus naturally reducing the number of feeders from that necessary to cover the whole area uniformly - with a commensurate reduction in cost?

2. If the wind, and thus generation profile has the characteristics of "profile one" then would not the logic of the Applicant's 34.5 kV collector system plan and the associated cost structure break down? Would not the cost structure for the collector system drop possibly by 50% or more? Let us note that profile one is a near best case wind generation profile for feeder loading, However:

   2.1. Do not the Applicants seem to have implicitly assumed something more like profile two, which is a near worst case?

   2.2 Is it not possible to take a projected "normal wind generation profile" and stream line the design of the collector system, and materially reduce costs, by accepting that if there is simultaneously peak generation and loss of some transformer or feeder then generation would be restricted? May not the economics favor such a solution provided it was anticipated to occur infrequently enough and for only very short durations?

3. Everything considered, especially the wind generation profile, could not the cost of the collector system be materially reduced by handling some reliability issues by a "rapid response" approach rather than dual redundancy of equipment (feeders and transformers) that is the basis of the Applicant's calculations? That is, is there not cost savings possible by considering reliability an economic issue to be planned and managed rather than a "lights out" issue to be protected against? Factors such as the following would need to be evaluated:

   3.1. What is the net effect of using single transformers and keeping a spare at the ready to be immediately installed rather than install two transformers at each station? A near mobile transformer, which would be easier for the lower voltages of Option 3 could cover a number of stations.

3.2. What is the probability of feeders being out at peak generation? Should not a plan that covers peak generation with all feeders in service, and allows feeder sharing for loss of one (or more) feeder be considered?

3.3. Since feeder outage and simultaneous peak load seem to force increased costs in the Applicant’s 34.5 kV collector system layout, would it not be reasonable and prudent to evaluate the benefits of using high temperature (and thus high emergency rating) conductors to accommodate these conditions? Since the frequency and duration of these simultaneous conditions are likely relatively small, could not MW losses be rationally ignored in such cases?

What can we conclude? It seems that we may tentatively conclude the following:

1. It is imperative that the collector system be an integral part of the transmission plan since the common points, the sub station design and locations, are in many ways critical to both. The 34.5 kV collector system must be deigned in and not added later as an after thought for best results.
2. Further analysis, and improved data, could probably dramatically reduce the collector system costs compared to the estimates provided by the applicants.

Finally, the issue of separate 34.5 kV versus underbuild 34.5 kV lines should be revisited since there appear to be significant assumptions made (such as ignoring right of way costs) and relatively small cost differences in the Applicant’s analysis. Moreover, underbuild construction occurs too frequently for there not to be some basic merit.

Q: What benefit would accrue by including the collector system in the Application as part of an integrated plan to the goal of achieving viable wind power generation and associated local industry in the Buffalo Ridge Area?

A: A major impediment to local farmers and other low capitalized concerns is the up front capital required for generation and collector system installation. Including the collector system in the transmission system upgrade would materially reduce the impediment to wind generation and move the goal of building a commercial wind generation industry in Minnesota forward. Moreover, by developing the plans for the 34.5 kV collector system early and including it as part of an integrated electrical wind power export concept, orderly and cost effective development of the wind generation potential is nurtured. Minnesota plans for renewable energy are advanced.

Q: Explain why Option 3 more naturally supports construction and operation of a 34.5 kV collector system than does Option 1.

A: There are a number of reasons why Option 3 provides a more supportive environment for the collector system than Option 1 including:

1. The cost of connecting to the lower 15 kV and 161 kV voltages of Option 3 is materially less than connecting to the 345 kV voltage of Option 1. Thus there are likely to be more connection points from the collector system (over time), which will tend to reduce MW losses and increase reliability.

2. The stronger high voltage transmission system of Option 3, tends to buffer the low voltage systems and associated equipment such as the 34.5 kV collector system from abnormal electrical conditions during disturbances and outages on the extra high voltage grid.

Finally, it should be noted that comments on the collector system are of necessity a high level and hypothetical at this time because much crucial information is not available, for example, the likely locations and layout of the wind generators.

Q: What are the possible community benefits of Option 3 compared to Option 1?

A: The possible benefits from Option 3 versus Option 1 flow from the primary fact that Option 3 better supports and nurtures a local wind generation industry in the Buffalo Ridge area than does Option 1. Consequential benefits flow through to landowners that can generate additional income, construction and service jobs are established by necessity and businesses start-ups and other local businesses benefitting from general economic growth, and the community receives the benefit of direct and indirect taxes In summary, the wind generation has the potential as technology evolves to be an material factor in the local economy, particularly as cost and price trends move in its favor, and environmental concerns and restrictions restrict and make less economic the fossil fuel alternatives. Wind can be to the local Buffalo Ridge landowners what the small oil wells were to some rocky mountain state ranchers a few decades ago - a very solid secondary source of income.

Decision Criteria (Minnesota Rule 7849.0120)

Q: What is the purpose of this section?

A: The purpose of this section is to consider how the selection of Option 3, as opposed to Option 1, satisfies some of the more directly relevant parts of the state decision criteria.

Q: Criteria Part A. Would substitution of Option 3 of the Application for Option 1 result in any adverse effects on operation of the electrical grid, customers, people of Minnesota or neighboring states, etc.

A: No. The Applicants state and their own studies show that both Options 1 and Option 3 can meet the specified needs.

Q: Criteria Part B. Is there a reasonable and prudent alternative to Option 1, the Applicant's preference?

A: Yes, by the Applicants own studies Option 3 is a prudent and reasonable alternative. Moreover, with the recent correction for construction costs and the removal of the errors in assigning loss related costs Option 3 is a probably the much cheaper option.

Q: Criteria Part C. Do Options 3 and 1 provide benefits to society compatible with protecting the natural and socioeconomic environments including human health?

A: Yes, both Options 3 and option 1 appear to meet these criteria. However, Option 3 would tend to meet the criteria better at lower cost. For example, the lower voltage lines of Option 3 will tend to have both a smaller environmental footprint than the larger 345 kV construction of Option 1. Option 3 is more supportive and nurturing of the local wind power and related industries in the Buffalo Ridge Area, and finally lower voltage lines tend to create less radiation (EMF) effect.

Q: Does either Options 3 or 1 violate any Federal, State or local rules and regulations?

A: It would appear at this early stage in the process that either Options 1 or 3 can be made to comply with all rules and regulations.

Q: Does this complete your testimony?

A: Yes, it does.