Questions for William Kaul
Great River Energy
Committee on Energy and Natural Resources Hearing- June 17, 2008

Questions from Senator Bingaman:

1) You say that you had to get legislation passed to facilitate the process to ensure cost recovering and permitting. Was that just in Minnesota or were there elements in the laws of other states that had to be changed? Is there something that we should do at the federal level in legislation?

   Mr. Kaul response: The legislative changes in Minnesota included addressing the issues of regulatory lag in cost recovery for investor-owned utilities, giving regional reliability and the electricity market due consideration in the certificate of need process, placing all transmission permitting within the purview of a single state agency and allowing for the transfer of transmission assets into a Transco if deemed in the public interest by the Minnesota Public Utilities Commission. Legislative changes sought and achieved in North Dakota and South Dakota addressed the regulatory lag issue only as other changes were deemed unnecessary. In our region, permitting and siting issues continue to take time (oftentimes 2 to 3 years) but the issues have not developed to the point that requires a federal role.

   Having said that - viewing transmission expansion primarily from the point of view of enabling the development of renewable energy resources - there have been significant delays and controversy surrounding the certificate of need process in Minnesota for two transmission lines that provide an outlet for the proposed Big Stone II coal plant, located in South Dakota, just across from the Minnesota border. There are significant unresolved issues associated with that project, related to carbon emissions from the plant, even though it is not located in Minnesota. The Minnesota Public Utilities Commission has delayed making a decision on the transmission line certificate of need pending further development of the record around future risks and liabilities for ratepayers for carbon costs.

   The CapX 2020 collaboration, as an open access, non-discriminatory common carrier, does not take any positions on the relative merits of various sources of generation, as required by the National Energy Policy Act of 1992.

   As the market for renewable energy develops regionally, and the need for significant new, extra high voltage (EHV) transmission materializes, a much broader regional collaboration will be necessary and the collaboration needs to include key regulatory and legislative policy makers in addition to transmission utilities. Initiatives are underway attempting to meet the challenges.

   For example, the Midwest ISO (MISO) has begun a process of developing a transmission grid expansion plan and a new transmission tariff for renewable energy development within a 13 state region. The first phase of the plan is to be completed in June 2009. Also, the Midwestern Governors Association (MGA) has a working group addressing the challenges of expanding the transmission grid for the purpose of developing renewable energy in its broad Midwestern region. The challenges are significant and if the MISO and the MGA are unable to meet them, a strong argument for federal legislation and/or regulation, multi-state siting and/or cost recovery could evolve. While time is of the essence - since the planning horizon for a large scale, inter-regional EHVgrid expansion is many years - the need for federal role in this region is not immediate. The CapX 2020 planning horizon is now in the 2016-2025 timeframe and these are the very issues we face.

2) Does the Midwest ISO cost allocation formula on file at FERC, that is 80% participant funding/20% rolled-in cost, facilitate the construction of new transmission for renewables?

   Mr. Kaul response: Inadvertently. While it never was intended to, the MISO "reliability" 80/20 tariff will provide a substantial ancillary benefit for wind development with the initial group of CapX 2020 projects. Actually, MISO has three tariff formulas in place that apply to projects depending on how they are classified, either as reliability, generation interconnection or economic. The 80/20 tariff formula is for projects that fit into the reliability category. Different cost allocation formulas apply for projects classified as generation interconnection or economic. In the reliability category, 80% is paid by customers in the geographic area whose service reliability is directly affected by the project. The 20% portion is rolled-in or "postage stamp" MISO-wide. The rolled-in portion (the 20%) of the tariff only applies to projects 345 kV or greater. CapX 2020 has two projects that were designed to address system reliability issues and likely will be classified as such, but that will also provide significant additional transfer capability to the system.

   The MISO generator interconnection tariff is the tariff directly relevant to wind generators. However, this tariff was developed prior to the time when the transmission service request queues started filling up with wind projects. It was designed more for the gas turbine projects of the day and worked well for that purpose. It calls for the generation developer to pay for 50% of the network upgrades necessary for reliable operation of the system caused by the generator's project. The other 50% is paid by local customers who derive a reliability benefit from the network upgrades. It's widely acknowledged that the generator interconnection tariff does not work well for wind projects. That is because the transmission developer must be able to identify the wind project developers at the time the transmission project is proposed. Since major transmission projects have a 5 to 7 year or longer lead time and wind projects have just a 2 year or shorter lead time, it is impossible to line up the developer's 50% commitment when the transmission project is proposed. Wind project developers cannot negotiate power purchase agreements (PPAs) that far in advance.

The California ISO has come up with, and the FERC has approved, an innovative financing approach that has the transmission owner pay all capital costs up front. Until the transmission investment later is recouped from wind generators as they interconnect to the transmission line, the transmission owner begins recovering the investment from its retail customers. Other regions, including ours, are looking at this approach to the extent it can be applied to certain types of transmission lines.

In our view, cost allocation procedures should take an inclusive, long-term view of project benefits and allocate costs over an appropriate size region. The mechanism(s) should be understandable and predictable without unreasonable analysis requirements and administrative burden. As mentioned above, MISO is working with stakeholders to propose a tariff that will facilitate the development of renewable resources in this region.

Once again I will refer you to the White Paper on principles of cost allocation and recovery commissioned by the WIRES organization, included with my testimony.

Questions from Senator Domenici:

1) You testified that CAPX is a "joint ownership" initiative that involves investor-owned, municipal and cooperative utilities in the planning, financing and ownership of transmission upgrades. What are the benefits of the "joint ownership" model and why did you proceed in this manner?

   Mr. Kaul response: The Upper Midwest is populated with numerous non-profit cooperative and municipal utilities, as well as investor-owned utilities. These business models each have their advantages. For the non-profits, the advantages are low cost capital that can be leveraged for consumer benefit and self-regulation. Investor-owned utilities provide good investment opportunities in a highly capital intensive business that needs to attract capital. Joint ownership provides each business model an opportunity to achieve its goals. It also presents an opportunity to coordinate and gain consumer, landowner and political support for large-scale transmission projects. The CapX 2020 joint ownership model further provides efficiencies in planning, constructing and operating facilities, reducing the need for redundant functions and facilities in our overlapping geographies.

2) Are there other successful examples of "joint ownership" of transmission in the U.S?

   Mr. Kaul response: Joint ownership is not new – this model was used during the last major infrastructure build-out in the 1970's for new generation and transmission. Many power plants are jointly owned by multiple parties that include public power, cooperatives and investor owned utilities. One of the oldest transmission joint ownership arrangements is the integrated system in Georgia, which is jointly owned by Georgia Power, Georgia Transmission Company (a cooperative) and the Municipal Electric Authority of Georgia. Some other examples include: the American Transmission Company (Wisconsin Public Power Inc. owns 5.7% of the company); and Cinergy, Wabash Valley Power Association, and Indiana Municipal Power Agency which own a Joint Transmission System covering two-thirds of Indiana, part of Ohio and a small part of Kentucky.

Areas where joint ownership exists as the transmission development model have more robust integrated planning and development. This, generally, results in fewer transmission reliability and capacity deficiencies than occur in areas without joint ownership. We believe that joint ownership could facilitate financing and construction of transmission in every part of the country, given sufficient support from Congress and the FERC.

3) The State of Minnesota has a very aggressive state RPS requirement – 30% by 2020 for Xcel Energy and 25% by 2025 for other utilities. Is Minnesota on target to meet these RPS requirements?

   Mr. Kaul response: Minnesota utilities are on track to meet these requirements. One of the concerns at the time the bill was drafted was whether transmission system limitations would prevent achieving the RPS. To address that concern, the legislation also required a transmission study that would identify new transmission facilities necessary to meet milestones in 2010, 2012, 2016, 2020 and 2025. That study was completed in November 2007. The result indicated that the CapX 2020 utilities had in place, proposed or were planning new projects to achieve the milestones through 2016.

   As indicated in my testimony, meeting milestones beyond 2016 requires the integration of Minnesota RPS requirements with those of a larger market – going from 6000 MW to 15,000 MW or more; thus, efforts were launched by MISO, the MGA and CapX 2020 to look at broader regional planning. However, there are significant issues associated with transmission cost allocation if we are to build transmission beyond the needs of the Minnesota RPS. The current MISO tariff options do not meet the market needs for transmission development on this much broader scale, primarily for renewable energy development.

4) In general, is it advisable to mandate a transmission line to carry only renewable resources?

   Mr. Kaul response: No. Laws of physics and concerns about reliability and economics militate against such a mandate. Additionally, the Energy Policy Act of 1992 prohibits discriminatory use of the transmission system and therefore requires all generation resources equal access and use of the transmission grid. A national policy on carbon and/or renewable energy portfolio standards would be a more effective approach if the Congress wants to accelerate renewable energy development.

Given the capacity factor issues, shouldn't the construction of facilities needed to deliver wind also be available to deliver the back-up power and move other energy when the wind is not blowing?

Mr. Kaul response: Yes. Intermittent resources such as wind need not only back-up power but other ancillary services as well. These other ancillary services include such things as load following, frequency response and voltage support. The transmission system needs to be designed to integrate all sources of generation, in addition to intermittent resources, into the entire system and managed as a whole, to be efficient and maintain reliability. While it may be possible to use the transmission that was constructed for the wind to also provide the back-up power and ancillary services for the wind, siting the needed back-up generation to use the transmission for wind capacity may not be the best location for system reliability or economics. To achieve a high level of penetration of intermittent renewable resources in an area, such as wind, that area must be able to interact with other areas to maintain the required real-time load-generation balance. That interaction requires sufficient transmission capacity between the areas, and this consideration alone will require expanding the system.

Siting any generation is very fact specific and depends on the generation technology to be used. Transmission plays an important role in generation siting but there are many other factors such as fuel source, water source, labor availability and the ability of technology to maintain reliability to name a few.

5) The intermittent nature of renewable resources like wind present some challenges. How far off are future technological advances, such as electricity storage and better wind forecasting, which could help address some of these challenges?

Mr. Kaul response: As the amount of wind generation increases, the challenges of providing load-following, frequency response and voltage support will increase. There will be a real limit on how much intermittent energy can be accommodated by the electric grid, both in physical and economic terms. Industry experience to date, at lower levels of penetration of wind generation, has been mostly positive, especially in an organized market such as exists in MISO. However, there was a recent experience of system instability in Texas in which wind generation was a contributing factor. As penetration of intermittent resources increases, utilities will gain experience in managing the challenges, but we must be cautious. So far, storage remains in a research mode and not yet commercially viable. Integrating weather forecasts into operations will help some. Geographic scope and diversity of the intermittent resources will help smooth the variability, but a much more robust transmission system will be required to realize that benefit.

6) With the National Interest Electric Transmission Corridor process established in EPAct 2005, Congress sought to address the critical issue of transmission siting. However, at this time, these provisions haven’t been fully implemented and no line as

been sited pursuant to EPAct. Nevertheless, the NIETC process has been contentious.

I was surprised then to read some testimony – including that from Mr. Pickens and Mr. Freeman with the WIA – that suggested these Energy Policy Act authorities did not go far enough. Mr. Pickens goes so far as to call on Congress to provide FERC with exclusive jurisdiction to site new transmission for a renewable project. Please comment.

Mr. Kaul response: In the Upper Midwest where some state level RPS mandates exist, transmission developments are moving along without a lot of regulatory impediments. As stated in my testimony, moving beyond a single jurisdiction or into a broader region without relatively consistent policy alignment and interest in renewable energy development, difficulties in permitting and determining cost allocation can be expected. These challenges increase the risks of transmission and wind developments and add delays and costs to an already long and expensive process. In the event that regional collaborations, such as that being undertaken by the MGA and the MISO are not successful, then a federal authority may be necessary in some cases.

Once again, thank you for the opportunity to appear before the Committee.