UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Assessing the State of Wind Energy in Wholesale Electric Markets — Docket No. AD04-13-000

STATEMENT OF KEVIN PORTER OF EXETER ASSOCIATES, INC., FOR THE DECEMBER 1 TECHNICAL CONFERENCE

Good afternoon, and thank you for inviting me to speak at today's Technical Conference. I will be addressing questions three and four of this panel regarding the capacity value of wind and the costs of integrating wind on the bulk power grid. Exeter Associates, Inc., is an electricity and natural gas consulting company in Columbia, Maryland. Our clients include the U.S. Department of Energy, the U.S. Air Force, the Maryland Power Plant Research Program, and several state utility regulatory commissions and state consumer advocates across the country. My statement today is based on work I have conducted for the National Renewable Energy Laboratory's Wind Technology Program.

The Staff Paper correctly describes Loss of Load Probability, Effective Load Carrying Capability (ELCC), the complexities and difficulties of ELCC, and methods for approximating ELCC. However, there are disadvantages with methods of approximating ELCC that are not discussed in the Staff Paper, the most important of which is that it is an approximation, and the result may be to underestimate or overestimate capacity contribution. In general, measuring the capacity value of a wind generating plant over the top 10-20% of load hours in a year will slightly underestimate the ELCC. My concern is that too small a number of peak hours would be included in a capacity value calculation. To take the most extreme example, consider including the contribution of a wind generator to the top peak demand hour in a year. There, the capacity contribution of a wind generator may be much too high or too low.

These capacity methodologies have a financial impact as well as a reliability impact. If the estimated capacity value of wind is too low, then the system operator may end up committing to more reserves than are necessary, and not enough reserves if the established capacity value of wind is higher than it should be.

Three other regions are determining the capacity contribution of wind that were not discussed in the Staff Paper. The Mid-Continent Area Power Pool (MAPP) measures the median value of up to 10 years of wind generation (if available) during four hours each month, including the peak hour. The Southwest Power Pool (SPP) examines the top ten load hours and then picks the value for wind that is present 85% of the time. Most of the time, the capacity value for wind is in the low single digits, or basically near zero. I view the SPP methodology as pretty questionable, and I would note that many conventional units would not do well under this methodology. Finally, California is in the midst of evaluating the capacity value of renewable energy technologies, not just wind. Unique to California is that at least part of this effort is driven by that state's renewable portfolio standard that requires renewable resources to be "least cost best fit" with utility resource portfolios and will be a factor in ranking renewable resource bids in utility renewable RFP solicitations.

Some of the capacity value methodologies are in a state of transition. Reportedly, ISO New England is looking at determining the capacity credit via the capacity contribution of the top 100 peak hours in a year (or about 1% of the hours in a year).

That is perhaps too small a number of hours to adequately represent capacity contribution.

In addition, ISO New England and New York ISO waive provisions for wind requiring generators that receive capacity payments to bid into the day-ahead market. PJM retains this requirement for all generators, including wind. Because wind forecasting tends to be less accurate on a day-ahead basis as compared to an hour or two hours ahead basis, I am concerned that requiring wind generators to bid into the day-ahead market in order to be considered a capacity resource may impede the use of wind forecasting, and therefore, more accurate schedules of expected wind generation.

Therefore, here are some suggestions for what FERC can do:

- Encourage or require waiver of provisions that require wind generators to bid into day-ahead markets as long as statistically unbiased wind forecasting methodologies are used. My preference is for RTO-administered forecasting methodologies, with wind generators paying the costs and to use more sophisticated forecasting techniques than simple persistence. The California ISO Participating Intermittent Resources Program is one such example and is approved by FERC, but given the early stage of wind forecasting in power markets, some regional differences and experimentation is appropriate at this time.
- Ensure that the capacity contribution of generators is determined at least on a consistent basis, if not an equal basis to the calculation of capacity contributions for conventional units, and discourage use of discounting mechanisms such as is in place in SPP.

Large-Scale Wind Integration

Several government and utility studies have examined this issue in recent years, most of them examining relatively small levels of wind penetration. The results to date indicate that cost impacts of wind integration are relatively small at low levels of wind penetration (<10%), but that integration costs do increase as wind penetration increases. In addition, the need for additional generation to support wind generation is much less than generally represented. Even at moderate wind penetrations, the need for additional generation to compensate for wind variations is substantially less than one-for-one and is generally relatively small relative to the size of the wind plant. Also, the additional generation to compensate for wind variations does not need to balance the wind by itself, but instead needs to result in system balance. And as with capacity credit, wind forecasting could play a large role in minimizing these integration costs, as the primary integration costs of wind are driven by the uncertainty and the variability in wind output in the day-ahead unit commitment time frame.

As I mentioned, the integration studies to date have been done with relatively low levels of wind penetration. Newer studies are examining the integration costs of wind at higher penetrations of wind. One such study done in Xcel Energy's service territory in Minnesota examined the impacts of 1,500 MW of wind in Xcel's service territory, estimated to be about 10,000 MW by 2010 (i.e., 15% wind penetration). That study found integration costs at that level of wind penetration to be relatively modest, at about $4.50/MWh.

What are some uncertainties remaining with wind integration, or what is not known yet?

- How much integration costs increase with increasing levels of wind penetration, and whether this relationship is linear or nonlinear.
- It is thought that market-based balancing markets, as opposed to Order 888-style imbalance provisions, will lead to lower wind integration costs, although that has not yet been definitively shown.
- Impact of varying generation portfolios on wind integration costs.
- Development of simplified methods, i.e., “rules of thumb” for determining wind integration costs and impacts.
- The role of transmission congestion in getting ancillary services needed to support the wind generation to the control area.

Finally, data quality among transmission operators is becoming an issue as more wind energy is incorporated into the grid and questions are raised about wind integration costs. The analysis in the Rocky Mountain Area Transmission Study on potential conditional firm tariffs could only incorporate one of three planned case studies, in part because of data quality issues. Other studies in the West have found inconsistencies in data reporting on transmission paths in the West, such as not reporting net schedules on some transmission paths, or reporting total transfer capability of a path instead of operating transfer capability. Finally, some of the wind integration studies have also been hampered by a lack of quality data. Clearly, a better effort from all market participants is needed.

Thank you for the opportunity to present my thoughts to FERC, and I look forward to any questions you may have.