Xcel Energy

2004 Renewable RFP Wind Curtailment Analysis

Xcel Energy – Transmission Planning
March 2005

I. Executive Summary

The purpose of this analysis was to evaluate the ability of the PSCo transmission system to accommodate energy from wind facilities being considered by the Company under the 2004 Renewable Energy RFP. Specifically, the analysis addresses the studies described in Exhibit 22, item 1, of the Stipulation and Settlement Agreement between the Company and the CEC in Docket 04A-325E. The primary objective of the analyses was to determine whether particular wind generation additions would impact the PSCo transmission system such that some of the proposed wind generators might be required to reduce their output under certain system conditions as well as the extent such curtailment of generation might be required in order to maintain system reliability standards.

Wind generation portfolios were provided by Xcel Energy Resource Planning and Bidding (RPB), and analyzed at various load levels for the years 2006 through 2007. In January 2005, RPB provided their chosen "short-list" portfolio, which consists of three bids. Table 1 shows the bids chosen for transmission analysis.

Table 1

Bidder	Location	Size (MW)
Short List Portfolio		
16	New Substation on the Pawnee – Daniels Park 230kV line (Corner Point)	199
15	New Substation on the Sidney – N. Yuma 230kV line	130
B1	Lamar Substation	69

Initial Study Conclusions:

1. The curtailment risk associated with any new generating facility at Lamar is directly related to operation of the Lamar DC Tie and the Colorado Green wind generation. The combined capacities of these two existing facilities (DC tie = 210 MW, Colo Green = 162 MW) exceed PSCo's 277 MW capacity share of the Lamar – Boone 230kV line. In order to quantify the curtailment risk of Bid #B1, projections would have to be made regarding the operation of the two existing facilities at Lamar in conjunction with the expected utilization of the DC Tie for imports into Colorado. Such an analysis requires use of a production simulation model. Transmission Planning does not possess or run such models and therefore did not attempt to quantify the curtailment risk associated with wind facilities in the Lamar area.

2. Studies showed that for a small percentage of hours during the year, there is a potential for unacceptable loading of the PSCo transmission system associated with Bid #15 and Bid #16. These conditions are compounded if one considers simultaneous operation of the two bids at maximum output during periods of high system peak demand (e.g., summer peak conditions).

   New generation located at or north of Pawnee can cause contingency loading on the Pawnee – Ft. Lupton 230kV line and the Bijou Tap – Ft. Morgan 115kV line during peak load conditions. However, the studies also indicated that reducing the generation to the north of those transmission lines could alleviate those conditions. This could be done by reducing PSCo gas-fired generation such as Manchief by up to 270 MW, or by reducing the nameplate capacity of the proposed wind in this area.

Recent Developments:
Resource Planning and Bidding notified Transmission Planning of recent developments that have resulted in changes to the January 2005 selected portfolio of wind bids. These changes include a reduction in the nameplate capacity of short-list Bid #15 from 130 MW to 60 MW and the withdrawal of short-list Bid #16 from the negotiation process. Although Transmission Planning did not re-evaluate the revised short-list portfolio, it is reasonable to conclude that these developments will alleviate the contingency loading concerns noted above.

As a result of the changes noted above, the RPB group is in the process of evaluating additional "back-up" bids that could potentially supplement the renewable portfolio. Once these bids are firmed up, Transmission Planning will perform additional curtailment analyses for the modified portfolio.

III. Power Flow Models and Assumptions

To begin this analysis, the PSCo historical hourly obligation load data was used to create load duration curves (LDC's) for 2001, 2002, and 2003. The Load duration curves were used to show the percentage of time (or probability) that system load would be at, or below a particular level, or to quantify the peak load level that for a particular probability, the actual load would be at that level or less. For example, in 2003, 98% of the time the PSCo load was at 5571 MW or lower. PSCo load levels were determined for 99th, 98th, 95th and 90th percent probability. Those load levels were compared to the peak load for that year to determine a percentage of peak load that could be associated with each of the probabilities. The percentage of peak value was then averaged for the three years for each of the probability levels. Those percentages could then be applied to a forecasted peak load to develop system models for future years.

As a starting point, power flow models were created to represent 2006-2007 peak load and high Tot 3 and Tot 7 conditions. The wind generation requests were modeled in the power flow studies at the requested point of interconnection locations. The studies used single contingency analysis to determine any unacceptable conditions resulting from the proposed wind facilities. When studies revealed unacceptable conditions, the next step was to determine if those conditions could be alleviated by adjusting generation dispatch and path flows, or if the wind generation had to be curtailed. Cases with less than peak loads were then used, if necessary, to determine how often the system could be at risk for the unacceptable transmission loading conditions. For the power flow models that represented anything less than 100% peak load conditions, generation was reduced to account for the lower load. The generation was reduced to reflect an economical dispatch according to fuel type/costs of the unit. All coal or base-load generation was scheduled at or near its full output. Combustion turbine (CT) generation was taken off-line where necessary and hydro generation was normally modeled operating at low output or off-line.

The following is a list of assumptions used for this study:

1. PSCo generation in the load flow cases was modeled in a manner that would attempt to represent economic dispatch patterns. When renewable bid generation was added to the case, the system generation was balanced by reducing higher cost resources.

2. Combustion turbine or combined cycle units were the only type of existing generation used for re-dispatching generation. Base-load (coal) units were not used for the re-dispatching of generation for either system intact or N-1 (single contingency) conditions.

3. When reducing the generation levels of thermal units to relieve or alleviate unacceptable transmission loadings in the load-flow models, thermal unit dispatch costs were used to decide the order in which generator output would be reduced (i.e., highest cost units were reduced first).

4. The load flow model representation used in these studies included the system infrastructure upgrades that are currently planned for the PSCo transmission system to the best knowledge of Transmission Planning at the time of studies. Any change in transmission infrastructure or generation within the 2006-2007 summer time frame could change the results of this analysis.

5. For this study, TOT3 and TOT7 were assumed to have high north to south power flows. TOT3 was modeled with a flow near 1400MW and TOT7 was modeled with a flow near 700MW. Higher or lower TOT3 and/or TOT7 flows could change the results of this curtailment analysis.

6. Plant maintenance outages, line or transformer maintenance outages, or other transmission system facility outages were not assumed for any of the models in this study. Any or all of these system conditions could affect the results of this analysis.

7. The power flow models created for this study were based on a Resource Planning April 2004 PSCo Summer Native Load Demand forecast. Significant changes in this forecast could affect the results of this curtailment analysis.