Wind Integration

I. Overview

A. Existing and Future Wind Development

As of December 2008, the installed wind capacity in the Pacific Northwest was almost 3,000 MW. Over 60% of this wind capacity is interconnected to Bonneville Power Administration's (BPA) Balancing Authority (BA), with the remainder interconnected to PacifiCorp West, PSE and NorthWestern Energy. "BA" refers to the area operator that matches generation with load. Over the next few years, there are several thousand megawatts planned for development in this region. The majority of existing and planned wind projects are located in the Lower Columbia region.

PSE's power portfolio benefits from 480 MW of wind capacity. We currently own two wind projects: Hopkins Ridge and Wild Horse. In addition, PSE has executed a 50 MW Purchased Power Agreement (PPA) for a portion of the output of the Klondike III facility, located in Oregon.

The Hopkins Ridge wind project is located in eastern Washington and has a capacity of 156.6 MW. Both the Hopkins Ridge and Klondike III wind projects are interconnected to BPA's BA. As a result, BPA provides integration services to manage the variable output of wind and delivers the hourly scheduled amount of wind generation to PSE's system. Because the Wild Horse wind project is located in central Washington and is interconnected to PSE's BA, our system must accommodate the variations in wind output. We plan to expand the Wild Horse wind project by an additional 44 MW by 2010.

B. Managing Variable Output

Wind generation is an intermittent and non-dispatchable generation resource. Like PSE's load, its variability can be managed, though the unpredictable nature of wind creates uncertainty. There can be large differences between a short-term wind generation forecast for hour- or-day-ahead time frames compared to the actual power produced. Short-term, unanticipated ramping events present some of our greatest challenges as we work to ensure that our electric system meets industry reliability standards.

If actual real-time generation output diverges from the hourly scheduled wind output, the operator must rebalance the system by increasing or decreasing generation from Mid-Columbia and other generating assets within our system. The instantaneous fluctuations are generally mitigated by Mid-Columbia hydroelectric generation, which is on automatic generation control (AGC) and can respond instantaneously. Regulation is the ability to meet moment-to-moment fluctuations in loads and wind generation to correct for unintended fluctuations. Regulation is met with generation that is online, spinning, and AGC equipped. Large, unanticipated ramping events must be managed within the hour with a combination of AGC and dispatcher actions. Wind generation following corrects for wind generation differences over longer time increments of 10 to 50 minutes between hourly scheduling adjustments. “Following” is the use of other generating facilities to compensate for un-forecasted decreases and increases in wind facility output.

II. Wind Integration Costs in IRP Modeling

For this IRP, PSE was able to estimate BPA wind integration costs, ascertained during workshops with BPA officials. As of October 2008, the best estimate of these rates was $3 a KW-Month. This rate estimate was escalated and a nominal cost was used. Other wind integration costs, such as imbalance charges, are consistent with PSE's experience in integrating the Wild Horse and Hopkins Ridge projects, and are described in more detail below.

III. Short Term Outlook Case Study

C. Integration of Hopkins Ridge Wind Project

PSE’s 156.6 MW Hopkins Ridge wind project is interconnected to BPA’s BA and integrated into BPA’s system. The hourly scheduled amount of power is delivered to our system. Wind is scheduled 30 minutes prior to the start of the hour and the schedule is automatically sent to BPA. The wind schedule is developed every hour using the most up-to-date information from a combination of actual real-time observations and vendor-provided forecast models. The forecast model employs publicly available weather forecasts, advanced statistical algorithms, numerical weather prediction models and a self-learning artificial intelligence logic.

BPA's integration services are two-fold: One service -- generation imbalance -- captures the after-the-fact difference between the hourly average generation that was scheduled, versus what was actually produced. The second service -- wind integration -- manages the second-to-second, minute-to-minute variability in wind generation by providing regulation and wind generation following. In October 2008, BPA implemented a wind integration rate of $0.68 per KW per month, or $3.11 per MWh assuming a 30% capacity factor, which was settled in the 2009 BPA Wind Integration Rate Case. This rate resulted in a fixed monthly charge of $106,488 which translates to approximately $4 to $6 per MWh depending on the amount of monthly generation produced. This megawatt-hour cost increases if less monthly wind generation is produced.

Customer workshops leading up to the 2010 - 2011 BPA Power and Transmission Rate Cases, which will set a new wind integration rate effective Oct. 1, 2009, suggest that the rate will increase to $2.73 per KW per month, or $12.47 per MWh assuming a 30% capacity factor. This rate is more than four times higher than the rate set in BPA's 2009 Wind Integration Rate Case and does not include the Generation Imbalance, Unauthorized Increase Charge or Failure to Comply penalties that BPA may also assess.

BPA's anticipated wind integration rate of $2.73 per KW per month is based on a wind scheduling accuracy assumption of a 2-hour persistence forecast. A 2-hour persistence forecast assumes that the hourly average wind generation observed two hours ago is the forecast or schedule for the next hour. If BPA assumes a higher wind scheduling accuracy (less forecast error) such as a 60-minute or a 30-minute persistence forecast, then the rate could decrease to $1.37 per KW per month, or $6.26 per MWh assuming a 30% capacity factor, according to the details released by BPA in January 2009. At this time, BPA is still using the 2-hour scheduling accuracy and has not committed to using a higher wind scheduling accuracy to reduce the wind integration cost.

D. Integration of Wild Horse Wind Project

For most of the calendar year, PSE's 1,100 MW share of Mid-Columbia hydroelectric generation is sufficient to manage the instantaneous Wild Horse wind and load variability and deviations from its schedule. Wild Horse wind output is scheduled at 30 minutes prior to the start of the hour using similar tools described for Hopkins Ridge.

During the spring runoff period when the Columbia River flows are high, the Mid-Columbia hydroelectric system has to be managed to stay within the legal Total

Dissolved Gas (TDG) limits by minimizing spill. Mid-Columbia flexibility is limited between available capacity and the minimum generation limit that does not violate the TDG limits. To stay below the TDG limits, spill must be avoided completely or minimized by operating close to turbine capacity. This type of operation results in limited upward and downward generation flexibility. If wind output is less than scheduled, the system must respond by increasing generation elsewhere. However, the Mid-Columbia cannot respond because it is already operating at capacity. During off-peak hours, the Mid-Columbia hydroelectric generation and most of PSE's other resources are operating at or close to their minimum project generation. As a result, the system has limited downward flexibility to respond if the wind output is greater than scheduled.

When the Mid-Columbia system does not provide the necessary flexibility to manage the Wild Horse wind project, PSE uses its thermal resources and market transactions to balance the system. During spring 2008, PSE experienced insufficient Mid-Columbia flexibility and had to mitigate some of the wind output using our thermal resources. The thermal units were dispatched and operated at minimum, mid-point and maximum to provide the flexibility to either increase or decrease generation.

As PSE's Mid-Columbia contracts expire and undergo renegotiation, our share of Mid-Columbia hydroelectric generation will decrease over time. In addition, more restrictive protection of anadromous fish could also limit PSE's Mid-Columbia flexibility. Our current 1,100 MW share of Mid-Columbia could be less than 500 MW by 2020. As the Mid-Columbia capability decreases, PSE will have to rely more on other resources within our portfolio, as well as increased market transactions to address our system balancing needs.

1. Use of market resources to provide wind integration services

Short term market transactions, which smooth out the forecast error between forecast time horizons, are an important component of wind integration within PSE's current portfolio. As PSE's wind portfolio expands, they will continue to be a critical component into the future. Day-ahead markets allow us to balance positions given the forecast error which occurs between long-term models and day-ahead wind forecasts. Real time markets allow us to rebalance hourly positions for the forecast error that occurs between day-ahead scheduling and hour-ahead forecasts.

From time to time, PSE purchases ancillary energy in the short term and forward markets. Aside from energy itself, both “spinning” and “non-spinning” reserve energy can often be found in the market. Spinning reserve is defined as unused capacity that can be activated by the operator and is procured through devices that are synchronized to the network and able to affect the active power. Non-spinning reserve is defined as offline generating capacity that is capable of being brought online within 10 minutes. PSE generally has surplus non-spinning reserves, but at times can be deficit on spinning reserve as required by the Northwest Power Pool (NWPP). As a member of the NWPP Reserve Sharing Group, PSE is required to hold generation in reserve in order to meet our Contingency Reserve Obligation (CRO). Under the current calculation, PSE holds in standby as a contingency 5% of all hydropower and wind generation, plus 7% of all thermal generation online and loaded within the PSE BA. Of that total, at least 50% is obligated to be spinning and the remaining 50% can be non-spinning. Leaning on the short term markets to meet our CRO is sometimes useful and more economical than dispatching a thermal unit, but transmission and liquidity can challenge this reserves market. For transactions to meet the BA’s CRO, there must be a firm transmission path from source BA to sink BA. Because firm transmission is often unavailable in real time, a real time ancillary market is very hard to find.

PSE has had some limited success procuring ancillary products in the forward market. For a spring 2008 delivery, we secured 50 MW of spinning reserve capacity for a six-week period during the peak of the spring runoff. Long term capacity products help balance the PSE portfolio and should be considered as a viable option for wind integration.

2. Cost of integrating wind in PSE’s balancing authority

PSE’s Wind Integration Team is evaluating historical regulation and generation following requirements for both Wild Horse and Hopkins Ridge. In order to meet Washington state’s Renewable Portfolio Standards, PSE may add up to an additional 1,000 MW of wind to our current portfolio, yet we have not yet determined the interconnections of the new wind projects. To ensure that PSE is well positioned to manage the additional wind, all integration options are being evaluated to determine the least cost options. The cost associated with integrating wind in PSE’s BA can be divided into two categories: 1) within-hour balancing reserves (regulation and generation following) and 2) the opportunity cost of reshaping the Mid-Columbia hydroelectric generation and dispatching the thermal units.

If our internal study determines that PSE's existing portfolio does not provide the necessary flexibility to adhere to regulation, generation following and forecast error, then PSE may be required to improve the existing thermal fleet by adding AGC and coordinating controls. As a final option, we may also need to add new, flexible resources to our portfolio. We continue to study wind integration and look for opportunities to minimize such costs.

E. Integration of Klondike III Wind Project

The Klondike III project is interconnected to BPA's BA and receives the same wind integration services as Hopkins Ridge. PSE receives the forecasted wind output for both the day-ahead and next-hour time horizon from the project's owner/operator. The forecasted wind output is then scheduled with BPA, and PSE receives the hourly scheduled wind output for the next-hour. PSE has to mitigate the forecast error between the two time horizons, hour ahead and day ahead. However, the instantaneous wind variability and unanticipated wind ramps are managed by BPA's BA.

As negotiated in the PPA, PSE is not responsible for the cost of generation imbalance, but is required to pay for half of BPA's wind integration cost of $0.68 per KW per month, or $3.11 per MWh assuming a 30% capacity factor. As discussed above, the cost of wind integration will change when BPA's 2010 - 2011 Power and Transmission Rate Case concludes.

IV. Regional Challenges and Solutions

Wind development poses some new challenges for the region as well as opportunities for growth and system improvements. In the last few years, the region has gained a lot of knowledge and has developed new tools to help overcome some of the challenges. Several regional efforts focusing on issues related to wind integration are discussed below.

F. Wind Diversity

Most wind development has occurred in the same general geographical area, the Lower Columbia region. Wind projects that are developed and located within the same general geographical region lack diversity and may result in large, simultaneous and unscheduled swings in wind generation. Sufficient reserves must be held so that the system can respond to these swings. More geographically diverse, negatively correlated wind projects naturally smooth out the wind output. Geographic diversity between wind projects may provide real benefits and reduce the amount of reserves needed to manage the variability. Access to transmission lines is a key factor affecting wind diversity. New transmission lines are expensive, and access to existing lines is limited.

G. Flexibility on the Hydro System

To date, the Pacific Northwest's hydroelectric system has adequately accommodated the integration needs associated with wind power. However, recent dramatic growth in wind generation means that at times there is no longer sufficient system flexibility. This is evidenced by BPA announcing a temporary moratorium on accepting new Large Generator Interconnect Agreements until a more optimal integration solution can be found. Currently, there are already times of the year when the hydro system is not available to manage wind and BAs rely on thermal generation and market transactions. In the future, the region may observe shifts in the way the system is operated as new, creative and cost-effective solutions are developed.

H. Wind Forecasting

The science of wind generation forecasting is relatively new and there is limited wind speed data available for study purposes and to calibrate forecasting models. However, the accuracy of wind generation forecasts does continue to improve. Most operators closely monitor actual, real-time wind output and use a vendor-produced forecast to help predict wind output for the next hour and next day time horizons. Modeling techniques have a level of built-in probability or uncertainty that can be adjusted, and over time forecasts may improve. However, accuracy of less than a 30-minute persistence forecast appears to be an ongoing challenge.

Regionally, BPA has reported a large difference between actual wind generation and wind farm forecasts, which results in large generation imbalance needs. In September

2008, when BPA first shared its observation, the forecast level accuracy was at the 2-hour persistence forecast. By year end, however, improvements put the forecast accuracy closer to the 1-hour persistence forecast. This is an indication that even without sophisticated forecasting tools, noticeable system improvements are possible.

Operational benefits may be realized with either a single entity forecasting wind generation for an entire region, or a BA since these would allow for complete data sharing. However, we have no indication that the region would be willing to move to this type of forecasting, nor of how many other benefits could be gained from such a process.

I. Predicting Wind Ramps

One of the main challenges with wind forecasting is the ability to predict wind ramps. Wind ramps are large changes in the output of a wind farm over a short time frame, usually less than 30 minutes. BPA's Technology Innovation Group, in partnership with the California ISO, is funding a Wind Ramp Forecasting R&D proposal to forecast wind ramps in BPA BA. Wind ramps will be forecasted 36 hours ahead and tracked to real time. In the first year, vendors will use historical data to forecast 2006 and 2007 energy output at select wind plants. The vendors with the smallest errors will then have the opportunity to forecast all wind plants in BPA BA in 2010. The success of this project could significantly impact the PNW.

J. Thermal Generation on AGC

While some thermal units in PSE's portfolio can respond quickly, they cannot be used to respond instantaneously, like the Mid-Columbia hydroelectric generation, because they are not equipped with AGC. Those units that *are* considered to have fast response and appropriate operating characteristics are being evaluated to determine if installing AGC is the most economical option to gain the additional flexibility necessary to maintain system reliability. Operating thermal units on AGC will likely increase O&M costs for these generators as variable generation requirements increase.

K. Automatic Control of Wind

In order to successfully integrate wind generation, firming resources must have the capability to provide both up regulation and down regulation. From a system management perspective, each hourly position must be set to allow the wind generation to move up and down freely. While shedding generation is acceptable, shedding load is not. For the simple fact that generators can be curtailed, over generation is not considered to be a system reliability event as defined by both WECC and NERC. Conversely, not having enough generation is a major concern and addressed clearly by both organizations.

L. Market and Scheduling Practices

Currently there are two active forums exploring the potential for alleviating intra-hour scheduling challenges associated with integrating variable generation wind resources: One is the Northwest Wind Integration Action Plan (Action Plan), co-sponsored by BPA and the Northwest Power and Conservation Council, and comprised of representatives from Northwest utility, regulatory, consumer and environmental organizations. The other forum is the Joint Initiative Work Group (Joint Initiative), made up of ColumbiaGrid participants, Northern Tier Transmission Group, and WestConnect.

The Action Plan created 16 recommendations that would help with the integration of wind generation. Action Item 13 of the Action Plan found that reducing barriers to market system flexibility would help with integrating wind, and stated that *"it is critical to develop mechanisms for better utilizing the flexibility of the region's thermal resources as well as developing new products, services and business practices for exchanging energy and capacity <u>on a sub-hourly basis</u>"*. As a result, WSPP drafted an intra-hour capacity product, and created of the Joint Initiative. The goal of the Joint Initiative is to identify the business process changes required to enable sub-hourly energy and transmission scheduling. Definitive timelines for achieving the objectives and goals in these two forums are being developed.

Intra-hour schedules will reduce the length of uncertainty around wind generation. A shorter scheduling period provides more opportunities to adjust wind schedules more closely to what the actual output is and thus rely less on balancing resources to make up the difference. The down side of this is that more schedules require more administration, including creating, approving, and modifying schedules and e-tags. Large scale regional participation is not required to make this approach beneficial, although wide-spread participation would create more market liquidity and options available to BAs that are managing wind.

M. Dynamic Scheduling

Dynamic scheduling provides mechanisms to schedule resources from a source BA to a sink BA. Currently, BAs are capable of dynamically scheduling from across another BA, as long as the source and sink BAs are the same. However, the appropriate hardware is not yet in place to allow two BAs, and therefore two AGC systems, to communicate and dynamically transfer resources. Once the capability to dynamically schedule is in place, a wind facility interconnected to a BA will be able to use flexible resources from another BA to manage the variable output. This system will provide additional flexibility to the region and provide more market liquidity.

N. Wind Pooling and Wind Only Balancing Authority

A small group of Northwest utilities that manage wind power is discussing the possibility of creating a wind-only BA. The fundamental concept behind a wind-only BA is that it facilitates the integration of wind resources by combining signals from “diverse” wind-plants and optimizes this diversity. The BA would accept bids from flexible resources which help firm, shape, and balance the output generation products. The BA would receive the variable wind generation and deliver a fixed schedule to each participant in the BA based on the schedule provided by that participant. The system reliability would then be based on the summation of all the wind input data. With this arrangement, wind diversity helps greatly reduce the variation of the system, thereby decreasing the total wind integration cost.

There are many challenges and constraints to overcome, both technically and economically, to bring the wind-only BA to fruition. To be commercially viable, a wind-only BA would require a broad participation of wind resources with negatively correlated generation profiles. It also requires significant amounts of balancing resources to maintain system reliability and adequate assurance that resources will be available if needed. Determination and allocation of benefits and costs amongst BA participants could be insurmountable in forming the BA. Implementation and on-going costs to operate and mange the BA could be significant. However, a wind-only BA could provide the integration certainty wind developers need to construct plants.

O. ACE Diversity Interchange

Area control error (ACE) diversity interchange (ADI) offers a means of reducing the system control burden for any number of BAs within a group of BAs, without undue investment or sacrifice by any participant in a group. The method achieves a mutual reduction in regulation requirements and generator output adjustments (ramping). The impacts of wind integration on any one BA can be reduced by sharing flexible resources and operational constraints. Through ADI, BAs share ACE to reduce instantaneous generator movement by leveraging the diversity in their short-term load and resource balance. PSE became a member of the regional ADI program in 2008. While ADI helps distribute the response to the variability of wind, its impact is relatively small compared to the overall fluctuations in wind generation. ADI is minimal in cost to establish and maintain, and can be implemented in a matter of months. It requires broad participation to get meaningful effects.

P. Transmission

A significant cost to wind projects is the need to purchase transmission equal to the wind project nameplate rating. However, the actual capacity factor of a wind turbine, expressed as the ratio of average power output to its nameplate rating, is not as high. Many national targets assume an average capacity factor of around 30% for wind. Therefore, a typical wind generation project is not using its transmission line 70% of the time. As such, the unit cost of transmission for wind projects is much higher compared to a high capacity factor resource.

An option that allows a wind project to use a larger portion of its transmission rights is to locate wind and flexible resources in the same general area. The idea is that wind varies significantly and there is always room to schedule other flexible resources using the transmission that has already been assigned for the wind resource. Assigning 100% of transmission for a resource having the capacity in the 30% range is not the most optimum use of the transmission system.