Questions and Concerns Submitted by Northwest Renewable Project

Questions Related to the Idaho Wind Resource

1. *The second paragraph on page 25 stresses the importance of spatial diversity and the need to neither over, nor under-estimate it. It also states that EnerNex and WindLogics have conducted six previous studies. The hour-to-hour variability seen in the present study appears very large compared with other data I have seen for wind projects—how does it compare with the six other studies WindLogics and EnerNex performed?*

    We've not conducted that analysis, but I would say that there is substantially more diversity in the wind models for the other studies. The scenarios for Minnesota were spread out over two-thirds of the state plus the eastern half of the Dakotas. In Colorado, plants were located in the north, northeastern, east-central, and southeastern parts of the state. For Idaho Power's model, turbines were confined to a relatively narrow band running west to east across the state, which strikes me as having less geographical coverage than for the other studies.

    The specific meteorology of the region can also have an influence. There is certainly a difference in topography and likely in the meteorology between the front range of the Rockies and the Plains compared to southern Idaho.

2. *Table 6 on page 32 shows capacity factors for wind build-outs up to 1,200 MW for the three water years studied and all but one number is below 30%. That seems low compared with other projects being developed in the Northwest (most are above 30%). Is there some reason to believe that the wind resource in Idaho is generally of poorer quality than other regions in the Northwest? Capacity factors can often be increased with larger turbine blades (adjusting the turbine power curve). Low capacity factors can lead to greater hour to hour variability, the concern here is again over the larger than usual hour to hour variability of wind generation found in this study. Some analysis of whether an optimized power curve would make a significant difference should be engaged.*

    Table 9 on page 42 shows the reserve requirements as a function of installed wind capacity. Normally, the reserve requirements rise in absolute terms, but fall as a percentage of installed capacity decreases—however, they increase in this study. This is unprecedented in my experience, and appears to be in error without corroborating evidence that something is very different about the wind resource in Idaho compared with the rest of the world. This is an anomaly suggestive of error and should be addressed.

    Wind is a function of geography and as every place in the world is different it is expected each would have differences in wind capacities. Especially considering the Idaho wind resources are modeled along the Snake River Plain. The Snake River Plain is predominantly an east to west feature which is affected by storm systems (low pressure) that predominantly come in from the west off of the Pacific Ocean. The area is also subject to occasional high pressure systems that setup over the inland west. So it is possible that the Snake River Plain, although huge geographically, acts less geographically diverse than one might expect. The feature may tend to funnel the wind and be influenced by regional rather than local factors resulting in more symmetry in the wind output when compared to other studies that were not impacted by a feature like the Snake River Plain.

Additionally the wind resource portfolios were selected and scaled based on what was believed to be reasonable and likely. Consequently, at the higher penetration levels wind projects were larger in order to represent a utility scale project of 100 - 200 MW. At lower penetration levels the projects were more representative of PURPA projects in the 10-20 MW size. The effect of using larger project blocks to obtain the higher penetration levels may account for the difference noted.

Information available at windpowermaps.org can be used to compare estimated wind power resources throughout the Pacific Northwest (http://www.windpowermaps.org/windmaps/NWwindpower50_big.htm).

3. *Figure 28 is labeled "empirical", but the text indicates the Figure 27 power curve was used to generate it-is Figure 28 empirical in the sense that it relied on historical wind speed measurements (one or more anemometers), or does it represent the relationship of generation and wind speed in an actual plant over some historical period? Was this limited to 30 MW of generation, or directly scaled up by a multiplicative factor? If something other than scaling was done, what was it?*

Normally, there is just one or maybe up to three wind speed measurements for a wind turbine site (once it gets built, each tower has its own anemometer, but those are typically downstream of the turbine blades, and thought not to be particularly reliable). In Appendix A, does the x-axis on Figures 28 and 29 represent a single wind speed measurement for the site? If the answer is "yes", then the "fuzziness" of the results would be due to two factors:

1) *The fact that the power curve applied to the average wind speed over an hour isn't the same as applying it dynamically over shorter time periods because of the nonlinearity - wildest example: 30 minutes at zero wind speed and 30 minutes at 50 mph (cut out) would net zero generation, whereas an hour of 25 mph would be close to full output.*

2) *The single wind speed measurement is only approximately representative of what is happening across the turbine field. I just looked at the output from a wind farm where the wind speeds varied from 16 m/s to 22 m/s for a project of comparable size (<50 MW).*

My biggest question is over how the adjusted power curve was applied in the study. Was the modified power curve applied to hour-average wind speed data from the MM5 model for the specific site? Another way to have done it would be to apply a power curve to 5 minute MM5 output and then average the generation over the hour-maybe that's what was done? Also, where there were build-outs in excess of 30 MW, was the data scaled up or did the study somehow take into account the fuzziness of larger projects? Finally, did each project site have a separate extraction point for wind speed data from the MM5, or did some of them share—i.e., was one wind speed used for multiple project sites?

Only the five minute data was used in the transformation to wind energy production. Hourly values represent integrated values over the hour. We recognize that the single wind speed can only be approximately representative of what is happening across the entire grid cell in the model or in the local area in reality. Since we had an opportunity to calibrate this approach in another project, we employed it here.

In no circumstances was a single extraction point from the model used to represent more than about 30 MW of wind generation. To represent a larger project, enough grid points must be used so that this limit is not violated.

Questions Related to System Operations and Modeling

4. *At the bottom of page 40 is a discussion of modeling hourly loads. There is a reference to adding a random error of "pf +/- 2%". What does "pf" mean here? Does the error term follow some kind of distribution - e.g., normal with a mean of zero and standard deviation of 2%? Also, I didn't feel I understood what the point of this was - are we trying to simulate the ten minute behavior of loads given an hourly average, or is it an attempt at deriving a load forecast error. There doesn't seem to be a mathematical foundation for the latter. If the purpose here is to derive a forecast error, wouldn't that be better done more directly – i.e., by constructing a forecast and fitting a distribution to the errors? Was this same method applied to wind variability? If not, how was wind variability modeled, and how were the results in Table 8 derived?*

To calculate the numbers in Table 8, we used observed system load readings at 10-minute intervals for calendar year 2005 and synchronous 10-minute wind MW readings at each penetration level (from the synthetic wind time series derived for our study).

First, consider the load alone case. For each 10-minute load reading, we calculated its deviation in reference to the expected load for the hour in which it occurs. Please note this is one expected load per hour, with six 10-minute readings measured against it. As you may recall, we initially calculated the "expected" load as merely the average of the six 10-minute load readings occurring within the hour. However, based on suggestions made at the January

16, 2007 meeting in Portland, we decided to introduce some amount of forecast error on the expected load. Thus, we introduced an error selected randomly from a uniform distribution ranging from -2% to +2% (the "pf" in the report is a typo). So now each 10-minute load reading for 2005 (there are 52,560 of these) is compared against its corresponding (error-adjusted) expected load (there are 8,760 of these), resulting in a time series of 52,560 deviations (converted to absolute value). Figure 21 (p. 41) of the report illustrates a sample hour. We did not assume a distribution for these deviations, we merely calculated the level of reserve necessary to cover 98% of them to within our L10 (38.52 MW) requirements. This level of reserve is 38.9 MW (see Table-8). Our use of the L10 parameter is perhaps best illustrated with an example: for a deviation of 60 MW, our analysis determined that 21.48 MW of reserve was necessary to reduce the 10-minute deviation to the L10 limit of 38.52 MW.

Now, let's add in wind (because the process is similar, I'm going to use similar language to the load alone explanation). For each 10-minute load net wind reading, we calculated its deviation in reference to the expected load net wind for the hour in which it occurs. Again, this is one expected load net wind per hour, with six 10-minute readings measured against it. So now we need to calculate the expected load net wind for each hour. This will be the combination of the expected load (described previously) and the expected wind. Based on conversations with our operations personnel and input from the peer review group meeting in Portland, we decided the expected wind for a given hour is equal to the wind occurring at 5 minutes before the preceding hour (for example, the expected wind for 10:00-11:00 is the wind at 8:55). So now (as with load alone case) each 10-minute load net wind reading is compared against its corresponding expected load net wind, resulting in a time series of 52,560 deviations (converted to absolute value). Again, we assumed no distribution for these deviations; we merely calculated the level of reserve necessary to cover 98% of them to within our L10 requirements. Using the 300 MW penetration level as an example, this level of reserve is 64.9 MW (see Table 8).

5. *Under the Results heading on page 49, the third to the last sentence says that identical streamflow volumes and pool elevation targets were held for all simulations. By streamflow volumes, do you mean unregulated volumes, or were the regulated volumes replicated exactly. Were the elevation targets hourly, daily, weekly, or monthly? In other words, we are concerned over whether the model was allowed sufficient flexibility to adjust with the wind output.*

The daily inflow hydrograph was identical for all simulations for a given year (e.g. all 2000 simulations used the same inflow hydrograph). Brownlee Reservoir was constrained to meet fixed start-of-year and end-of-year headwater targets for all runs regardless of wind case (flat vs. actual). Between the fixed initial and final headwater conditions, Brownlee was free for all runs to move without constraint. Thus, the model was permitted ample flexibility to adjust with the wind output. Oxbow and Hells Canyon Reservoirs were <u>not</u> constrained with respect to start-of-year and end-of-year headwater targets. However, it is important to note the combined active reservoir storage of Oxbow and Hells Canyon is less than 2% of Brownlee Reservoir.

6. *Page 45 discusses the challenges of wind integration, particularly during light load and heavy load conditions. It is unclear why there should exist any problems during heavy load hours, except under extreme spill conditions. Since it is at Idaho's discretion how much wind to attempt to market on the next hour, they could choose to market none. If the wind doesn't blow, nothing changes. If the wind does blow, the hydro can be reduced to compensate - there would be no reason to hold a reserve on heavy load hours, and little danger of running out of reg-down capability at that time. The Europeans have said that the problems they have are at times when loads are low and they are otherwise at minimum generation. It is possible that wind could cause additional hydro spill (if the wind itself cannot be spilled) - but the value of the energy at that time would be zero anyway, so it is unclear to me whether that is actually an integration cost. If zero wind is scheduled on heavy load hours, there is no reason to assess wind variability from the standpoint of 65 minutes before the operating hour, further reducing the variability assumed in the study.*

Pages 49-50 and Figure 24 illustrate unnecessarily held reserves on the heavy load hours. If zero wind is scheduled over those hours, any wind that does appear would result in reduced on-peak generation. That wind energy would usually end up stored in the reservoir and be available for generation during peak hours the next day. During light load hours, there may be a need to maintain a higher level of generation on the hydro system in order to adjust downward in case the wind comes up. It is likely that the amount could be adjusted depending on actual wind activity and longer term forecast. For example, if there is zero wind generation on the current hour and zero throughout the day ahead forecast, there probably isn't much need to hold a higher minimum - at least not as high as when the wind is already generating significant energy.

Probably our biggest concern at this point is with the wind data showing more variability than any historical data we have seen, including data from BPA, PacifiCorp, and NREL representing a total of more than 1,000 MW of wind generation in the Northwest, mid west, and Texas.

Idaho Power is investigating the approach suggested by RNP. While this approach is interesting, Idaho Power has some concerns. First, we are concerned about significant operational changes that the Hells Canyon Complex would be subject to under this operational regime. Based on 2005 10-minute wind data, these are the wind levels exceeded by only 2% of the 10-minute readings:

- 300 MW - 269.9 MW
- 600 MW - 498.9 MW
- 900 MW - 692.1 MW
- 1,200 MW - 897.9 MW

So, if we are interpreting this approach correctly, we would need to carry 269.9 MW of reg-down during all HL hours for 300 MW of nameplate wind generation.

Our second concern is with modeling this approach. We are still giving this some thought, but at least initially, we are not clear on how we would simulate the approach RNP has suggested. Synexus Global has included new reserve modeling features in recent releases of the Vista program. These might make it easier to simulate the methodology RNP has suggested.

Questions Related to Operating Reserve Requirements

7. *The report refers to AGC constraint violations which are not defined as far as I can tell - are these instances when the model found itself unable to hold the requested reserve levels while meeting other hydro operating criteria (min flow, etc.)? If so, does the model assume that any shortfall of reserves is an "AGC Violation"?*

That is correct - any occurrence of the reserves not being maintained is counted as an AGC violation. The values for total system bi-directional reserve given in Table 9 on page 42 were input to the modeling using the AGC control reserve category in the Vista model. The level of reserve provided for each hour of a simulation is reported by the model. Hours for which the model is not capable of holding the requested level of AGC control are considered to constitute an "AGC Violation".

8. *On page 23 (fourth bullet) it is stated that incremental capacity requirements for contingency reserves were determined. How were those determined and entered into the model?*

For both the flat wind case and the actual wind case simulations, hour-to-hour contingency reserve equal to 5% of wind generation was input as a requirement in the Vista model. The only difference is that the contingency reserve for the flat wind case is invariant within a day (because the wind itself is invariant), whereas it varies from hour-to-hour for the actual wind case. The total MWh held in contingency reserve is equivalent between the cases.

9. *It is stated on page 39 that the analysis adopted 5-sigma as the regulating reserve coverage level. Why was that level chosen - does Idaho Power currently hold about 29 MW of AGC? This seems high, and if so, exaggerates the incremental needs associated with the wind.*

As discussed in the peer review process, the 5-sigma level is not meant to imply a level of confidence in terms of a statistical probability distribution. It has been described merely as a level of bi-directional reserve allowing acceptable coverage of fast fluctuations in Balancing Authority demand. Idaho Power currently holds regulating reserve equal to 1% of Balancing Authority demand. Based on this criterion, regulating reserve held by Idaho Power can range from about 10 to 30 MW.

10. *The equation on page 42 correctly shows how the different reserve requirements should add. However, the (unlabeled) illustration on page 47 suggests that the reserve requirements, once entered into the model are additive. Did the Idaho studies reduce one or the other calculated reserve requirements so they would not be summed by the model, or alternatively, enter them as a single total number?*

The equation on page 42 was used to derive the regulating reserve assumed for the Vista model runs. Regulating reserve is designated as AGC Control in the illustration on page 47, and is only one of two primary components of operating reserve commonly used in Vista and in typical Idaho Power practice. On top of regulating reserve, operating reserve also includes contingency reserve, with total operating reserve equal to the sum of contingency reserve and regulating reserve. For this study, Idaho Power assumed contingency reserve equal to 5% of hydroelectric and wind generation, and 7% of thermal generation. At least half of the contingency reserve must be held as spinning reserve. The illustration on page 47 accurately depicts the components of operating reserve as used in the Vista model. Contingency reserve was held for the flat and actual wind cases.

Questions Concerning the Use of 2000 Market Prices

11. *The use of year 2000 market prices to determine integration costs is not reasonable. Much has happened since 2000 - including fines, criminal indictments, and price caps to ensure that prices at that level will not return. Neither is it accurate to assume that price levels as high as those seen in 2000 are somehow related to hydro availability on the Hells Canyon hydro complex, or wind availability. While expressing integration costs as a percentage of market prices attempts to account for the anomalous behavior of prices that year, it was clearly insufficient to the task. A single set of prices is a more reasonable approach.*

When the integration cost is calculated as a percentage of market the unusually high prices in 2000 do not misrepresent the cost. Each pair of runs has the exact prices so it is the delta between the runs relative to the average market price that matters. The key component in determining cost is how the higher reserves in the variable case impact hydro value. In absolute terms we agree that at least in the near term the 2000 prices are higher than expected prices. However, the 1998 prices are significantly lower than expected future prices. In relative terms, the decreased portfolio value experienced in the variable wind cases (in all years) is valid when looked at as a percentage of the market price of power.

It is helpful to think of the integration cost not as a single number ($10.72/MWh) but as a dynamic function of wind and load characteristics and conditions, hydro conditions, market prices and transmission availability. The years used in the study were selected based on hydro conditions. It was thought that differing weather patterns experienced during low, median and high hydro years would potentially impact the amount and timing of the wind generation and ultimately, Idaho Power's ability to integrate wind generation on its system. The years were selected without regard to market conditions. To minimize bias, the study used the prices that actually occurred during the years investigated. We believe it more appropriate to utilize actual prices and focus on the integration costs as a % of market price than to arbitrarily assign market prices for any given year(s). However, the use of constant prices was investigated in sensitivity runs.

12. *This concern is further highlighted when the results obtained with actual power prices (exceptionally high in 2000, the normal water year – Table 2) are compared with results obtained when power prices from 2005 were used for all three years (Table 13). The results are significantly lower for the normal water year when the high 2000 prices are removed. The results also show that integration costs are lowest in the normal year. That is, costs appear to be higher when hydro is limited by low or high water and are lower when normal flexibility is available. The results should be based on the 2005 wholesale prices indicated in Table 13.*

The sensitivity runs establish that market prices matter when determining integration costs. Again we believe it more appropriate to use the prices that actually occurred and to move away from the simplistic notion that a single cost can be applied to a dynamic problem. We believe it is more correct to acknowledge that market prices matter and to move towards establishing a percentage of market integration cost framework. Energy has value at the market price of when it is available and to the extent accommodating wind diminishes the effective deployment of resources to capture the greatest value it should be held accountable. Your assertion that historic prices are not relevant is overly simplistic and misses the greater range of possibilities the historical prices approach considers.

13. *Sensitivities involving several price levels would also be appropriate - but establishing integration costs as some sort of weighted average of year 2000 prices is not supportable.*

The study makes no attempt to use a weighted average of 2000 prices in establishing the cost to accommodate wind. It was the % of market prices that was used in the calculation to establish an average integration cost for wind generation (see pages 4 & 5 of the introduction to the study) in % of market price. This percentage was then arbitrarily applied to the 2007 levelized PURPA rates to arrive at the $10.72/MWh wind integration cost.

Subsequent analysis indicates that an arbitrage situation occurred during 2000 as a result of the spread between the prices used to model the east (PV) and the west

(Mid-C) sides of Idaho Power's system. An analysis was run with PV prices being set to Mid-C prices – this eliminates the arbitrage opportunity. The results of this analysis confirm that the price differential between the Mid-C and PV prices, and the resulting arbitrage that was occurring during 2000, did have an influence on the resulting integration costs for 2000. As you can see from the tables below, by eliminating the arbitrage opportunity (Table 2), the resulting integration costs (as a percentage of market price) are fairly consistent with the percentages calculated for 1998 and 2005.

Results from Study Using Actual Palo Verde (PV) and Mid-Columbia (Mid-C) prices:

MW	1998	2000	2005	AVG
300	11.60%	16.60%	18.40%	15.53%
600	17.10%	22.90%	16.00%	18.67%
900	21.90%	29.60%	-	25.75%
1,200	25.10%	29.80%	-	-

Results with PV Prices Set Equal to Mid-C Prices to Remove Arbitrage Opportunity:

MW	1998	2000	2005	AVG
300	12.46%	11.04%	17.87%	13.79%
600	18.54%	17.50%	16.03%	17.35%
900	20.95%	21.91%	29.67%[1]	21.43%[2]
1,200	22.97%[1]	22.14%[1]	13.70%[1]	-

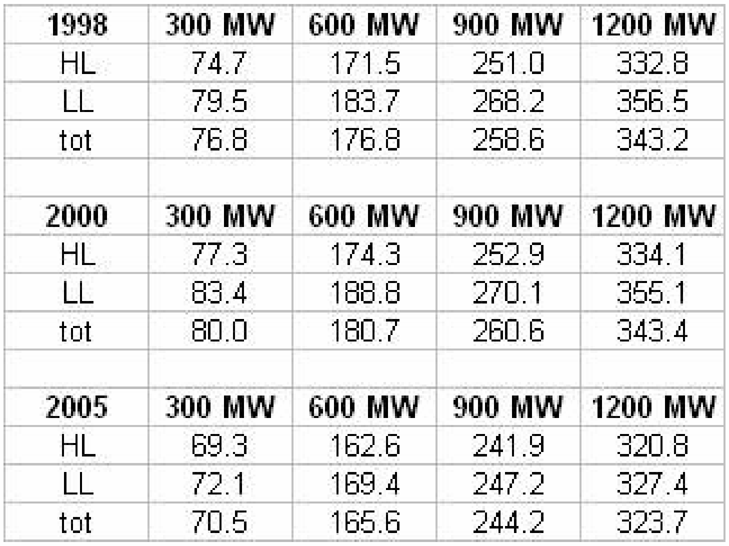
[1] Results not considered valid due to high number of AGC violations.

[2] Does not include 2005 results.

While this simplification does not recognize the real price differential that we see between the east and west side of our system, it does seem to indicate that the integration costs, when expressed as a percentage of market price are extremely consistent over a range of market prices (Mid-C): $28/MWh in 1998, $132/MWh in 2000 and $58/MWh in 2005. This is especially true when comparing the 1998 and 2000 data, which are the pricing extremes.

14. *The study reasonably attempts to ascertain integration costs by looking at the difference in system operating costs between two studies, one including hourly wind generation patterns, and the other with flat daily blocks of an equal amount of energy. However, there can be non-integration cost effects creeping in if the wind generation pattern favors either the higher value or lighter value hours of the day. The study should either be run with the daily energy blocks split into two (or possibly three) blocks, one for the heavy load hours and one for the light load hours. Each block would reflect the wind generation for that time period.*

We believe this idea has merit. However, the 24 hour block approach was presented and discussed with participants in this docket during previous workshops. The overall impact of this bias is thought to be small and could increase or decrease the wind integration cost (in actual fact, the numbers in terms of LL/HL capacity factors show that this bias only has the impact of increasing integration cost – see following table). At this point we have not revised the current approach; however, we will have additional information to share regarding this concept during the workshop.



1998	**300 MW**	**600 MW**	**900 MW**	**1200 MW**
HL	74.7	171.5	251.0	332.8
LL	79.5	183.7	268.2	356.5
tot	76.8	176.8	258.6	343.2
2000	**300 MW**	**600 MW**	**900 MW**	**1200 MW**
HL	77.3	174.3	252.9	334.1
LL	83.4	188.8	270.1	355.1
tot	80.0	180.7	260.6	343.4
2005	**300 MW**	**600 MW**	**900 MW**	**1200 MW**
HL	69.3	162.6	241.9	320.8
LL	72.1	169.4	247.2	327.4
tot	70.5	165.6	244.2	323.7