EXHIBIT B
PROPOSED METHODOLOGY FOR SUB-HOURLY ANALYSIS

Reserve generation has three primary purposes in power system operation:

1. To guarantee system reliability in the event of an unforeseen loss of supply resources
2. To assist in maintaining the frequency of the interconnection and balancing supply against demand and obligations over longer periods
3. To provide margin for uncertainties in forward operational time frames

The common methodology for assessing the cost of integrating wind energy into a utility control area is based on chronological simulations of scheduling and real-time operations. Production costing and other optimization tools are generally used to conduct these simulations. In most cases, the "time-step" for these simulations is in one-hour increments. Consequently, many details of real-time operation cannot be simulated explicitly. Generation capacity that is used by operators to manage the system in real-time – i.e. the units on AGC utilized by the EMS for both fast response to ACE and that which is frequently economically re-dispatched to follow changes in control area demand – is assigned to one or more reserve categories available in the various programs.

At this level of granularity, the total reserve requirements for the system are a constraint on the commitment and dispatch of units. Supply resources in the model are designated by their ability to contribute to the system requirements in one or more reserve categories. In the course of the optimization or economic dispatch, the solution algorithm must honor the system reserve needs, the therefore is not able to use some capacity to meet load or fulfill transactions.

Increasing a reserve requirement, therefore, does not in and of itself increase operating cost. There are many hours when enough units with the appropriate capability are spinning and loaded such that the reserve requirements are met. However, there may be hours where the system reserve requirement dictates that another unit be started or efficient units are kept below their maximums. Here costs will accrue, as the marginal cost to serve the load would be increased.

In this context, there are two primary types of reserves. The first is comprised of the excess capacity that must be carried at all times for reliability. These are generally known as "contingency reserves", and as the name implies, can only be utilized when an event that meets of the definition of a contingency actually occurs. Here, the operation of a breaker – as would be the case to remove come faulted equipment from service – is necessary. Changes in wind energy production due to mesoscale or locally-induced wind speed changes take place over longer periods of time, not instantaneously.

The second category of reserves is used to balance the supply with the control area demand on a continuous basis. This includes minute-by-minute (or faster) adjustments to generation to compensate for load variations and frequency economic dispatch of units with movement capability to follow slower variations in control area demand. The variability of wind energy production adds to the existing variability of the control area demand, although not arithmetically. Finally, because reserves must be allocated in advance of "real-time", additional amounts are allocated.

Real-time operation of power systems relies on vast amount of observations and complicated algorithms for continuous adjustment of supply resources. Because of this complexity, the preferred approach in past wind integration studies has been to use mathematical and statistical techniques to analyze the incremental variability and uncertainty contributed by wind generation. The incremental amounts are then mapped to the various categories of reserve allowed in the production costing analysis. It should be noted that treatment of reserves varies significantly across the universe of commercial production costing software, so approximations and compromises must usually be made to incorporate the reserve impacts of wind generation in the analysis.

The general procedure for employing these techniques to estimate incremental reserve requirements proceeds as follows:

1. Analyze the load by itself, employing various techniques to quantify metrics related to variability on fast (e.g. minute by minute or faster) and slower (ten minute periods) time scales.
2. Compare these metrics to known operating practices for reserve allocation. Adjust the algorithms to achieve correspondence, if necessary.
3. Analyze load net of wind generation to compute new variability metrics.
4. Apply the "transformations" developed in Step 2 to compute the new reserve operating reserve requirements.

A discussion of some algorithms that have been employed in previous studies follows. It should be noted that operating practices can dictate which specific approaches will work best in a given situation. For this effort, EnerNex will determine the precise approach after discussions with WAPA.

Algorithms for Assessing Incremental Variability and Uncertainty Impacts

To assess the regulation capacity needed to compensate for fast up and down fluctuations in control area demand, high resolution load data is compared to a "smoothed" version of itself. Figure 1 illustrates the trend characteristics and some actual load for a sixteen hour period.

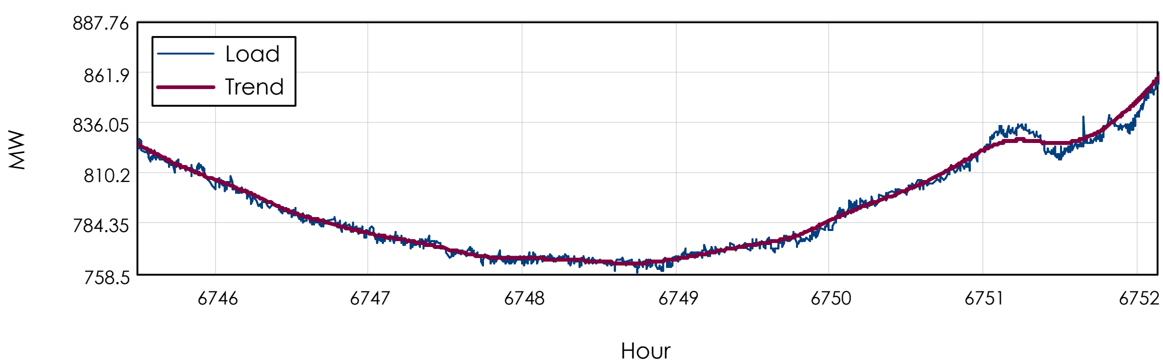

Figure 1.

By subtracting the trend value from the actual load, the deviation for that period is obtained. The time plot of the deviations for the trend and load from Figure 1 is shown in Figure 2.

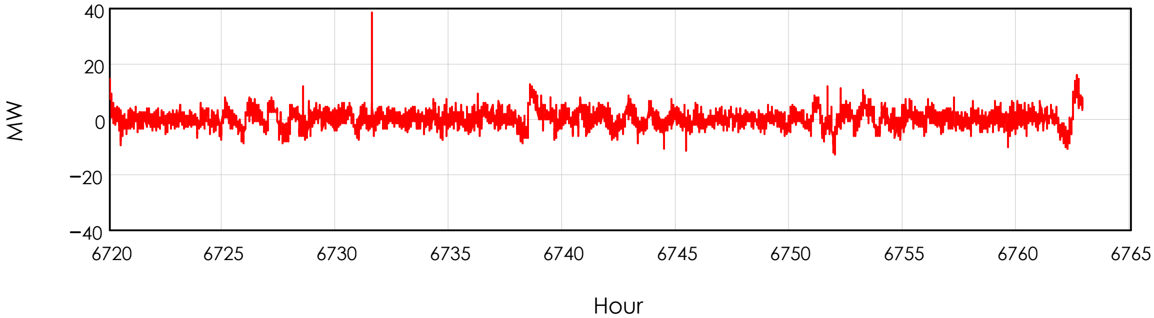

Figure 2.

The detailed view of deviations for one of the daily periods in Figure 3 reveals a distribution that is roughly normal with a mean of about zero (which results from the intentional selection of the trending period).

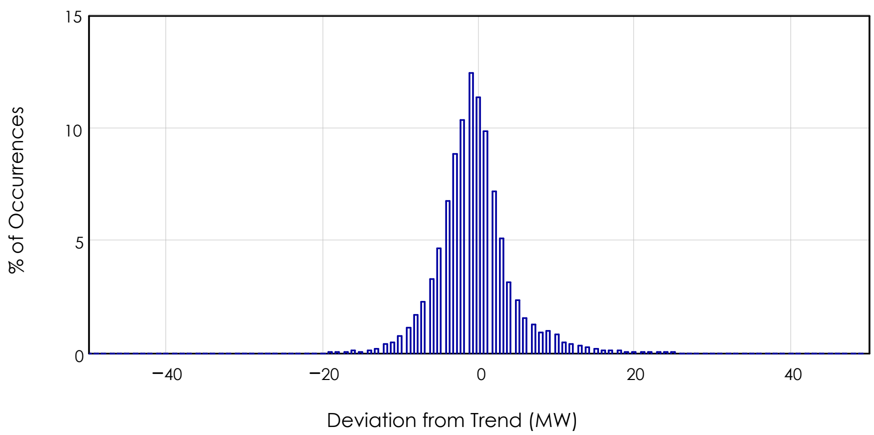

Figure 3.

Therefore, to compensate for almost all of these deviations, fast-responding regulation capacity equal to some multiple of the standard deviations would be necessary. Integration studies with other control areas have found this factor to range up to 5.

The amount of fast-responding generation capacity on AGC required to compensate for the fluctuations in control area demand about the smooth trend can be estimated from the statistical distribution of these variations over a period.

The results of this analysis can be used to determine how wind generation will affect the amount of reserves required to provide fast compensation for variations and support the frequency of the interconnection. This capacity must be available at all times, and is bi-directional; i.e. the fluctuations can be above or below the trend value at any moment. Capacity relegated to such duty cannot be utilized to serve load or meet control area energy obligations.

The next step in this analysis will be to determine how this minimum regulating capacity requirement would be affected by wind generation.

High resolution measurements obtained by NREL from operating wind plants of various sizes show that the standard deviation of the regulation characteristic can range from a few percent (<5%) for plants smaller than 50 MW to around 1% for plants 100 MW and larger.

These variations are almost certainly uncorrelated with the regulation variations of the load, since the former is driven by details of terrain and meteorology and the latter by individual customer choices and processes. The consequence of this statistical independence is that the variations of the load and wind combined can be estimated with simple algebra.

If the regulation characteristics of the individual subsets are truly uncorrelated, the regulation characteristic of the combination can be calculated from the statistics of the individual characteristics as follows:

$$\sigma_T = \sqrt{\sum \sigma_i^{\,2}}$$

where

σ_i = standard deviation of regulation characteristic of subset of load or wind

σ_T = standard deviation of regulation characteristics of aggregate control area demand

Other Intra-Hourly Variability

For a given hourly load in the data set for the study, there are periods during that hour where the demand is higher and lower than the average. Generation must be adjusted to meet these values within the hour. Figure 4 illustrates this with actual data.

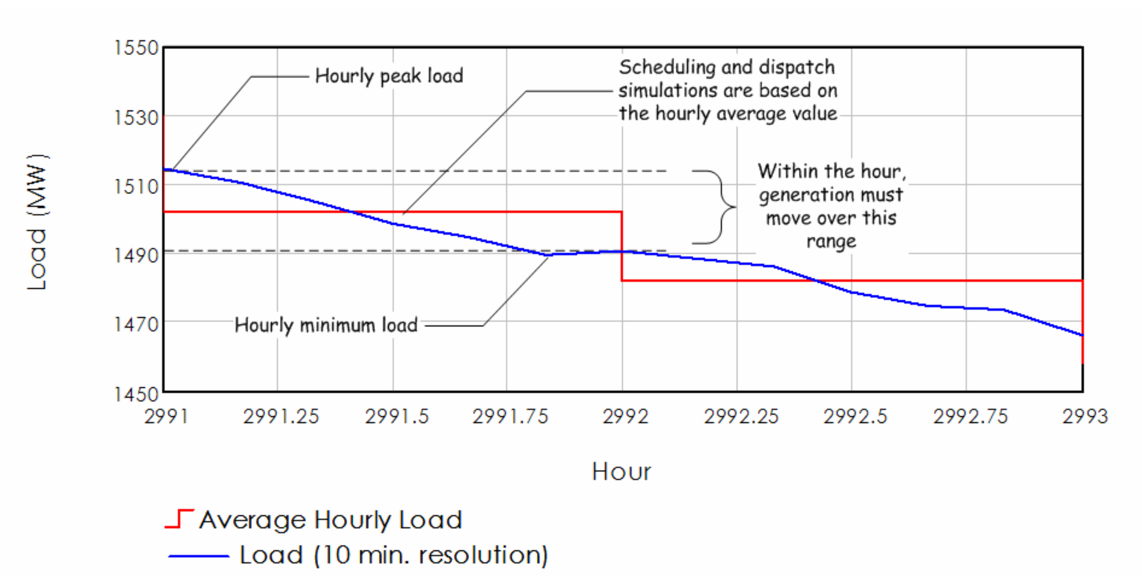

Figure 4. Hourly average and ten-minute load

The purpose of this document is to describe a procedure for estimating the additional flexibility within the hour that would be required to manage a control area with significant wind generation. The analysis and experimentation are based on an annual record of load and wind generation at ten-minute intervals. The goal is to develop a "rule" for the amount of flexibility that would be required using information that would be available in the control room. The extended data records also provide a way to "test" the proposed rules.

The procedure for determining the required flexibility for load alone is as follows:

1. Using the ten-minute data, compute the hourly average value for load
2. Compute the difference between each ten minute value of load and the hourly average. The difference is the load following requirement.
3. Where ramping between schedules takes place, as in the WECC where it takes place from 10 minutes before until 10 minutes after the hour, the "average" load value at the top of each hour is actually the average of the previous and next hour values (Figure 5). This adjustment will reduce the magnitude of the hourly load following "envelope", since the greatest departure of ten-minute values usually occur at the start and end of each hour using this method.
4. Devise an algorithm that could be implemented by operators to project the maneuverability that is needed to follow the load movements. For load alone, this algorithm is based on the previous hour average value (which is known) and the forecast average value for the next hour (which we will assume can be perfectly forecasted for load alone).
5. The estimated load following capability is then the difference between the next hour forecast average and the previous hour average.
6. The requirements are roughly symmetrical about the average value. In the morning, for example, the load at the beginning of the hour will be less than the hourly average. If the unit base points are moved to the hourly average, there will be a need to back some generation down, and then move it up over the hour as the load increases. This rough symmetry also makes the math easier, but of course may not apply to how the IPC operators do things.
7. This load following "rule" is tested with the ten-minute data. The number of ten-minute load values outside of the up and down load following bands is computed.

Figure 6 shows the results of the mathematical procedure described above in points 1 and 2.

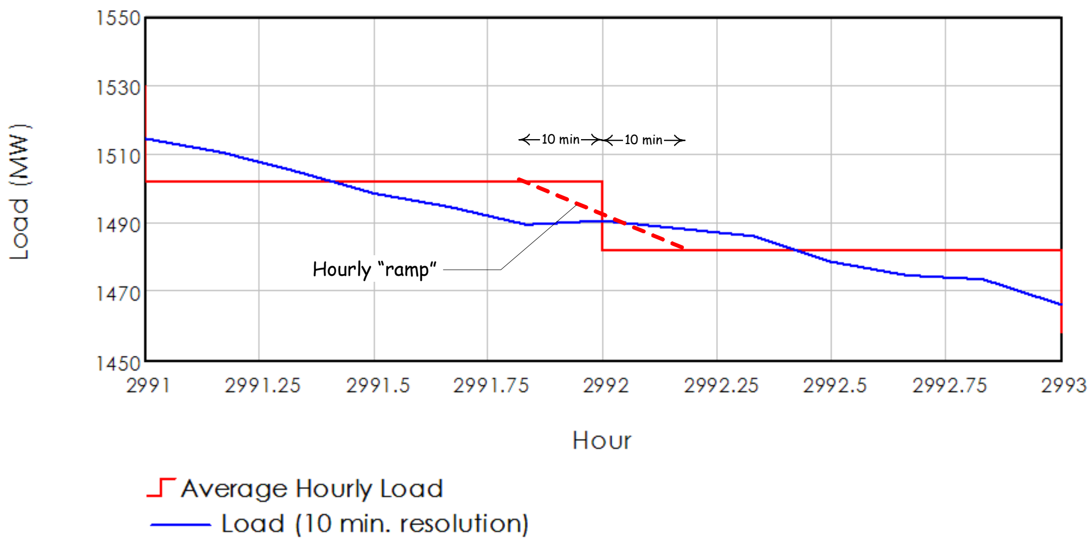

Figure 5.

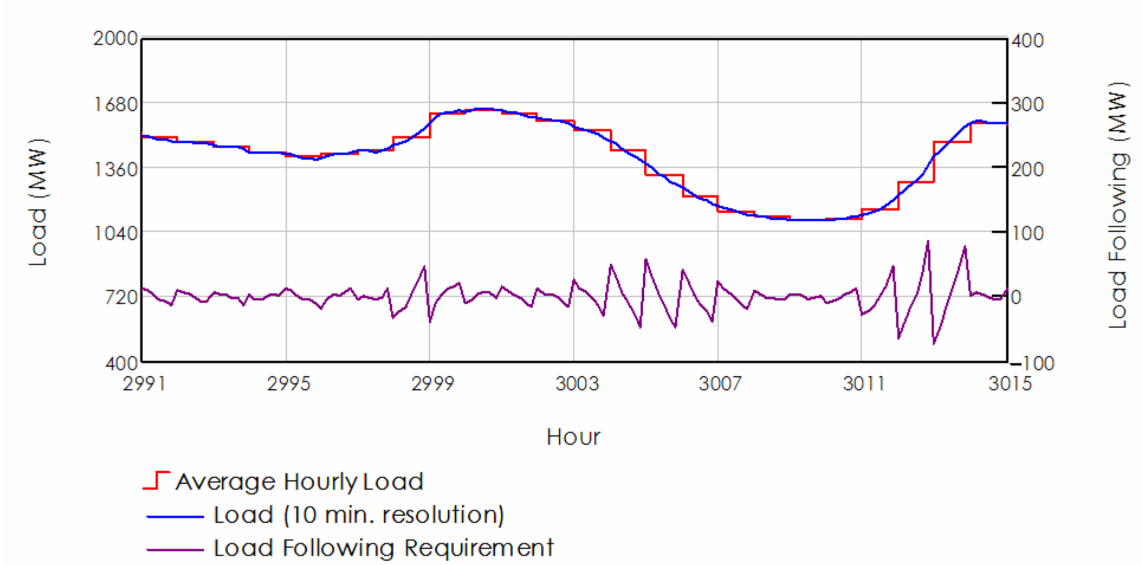

Figure 6. Hourly load, ten-minute load, and load following "requirement".

In this initial analysis of load following requirements, it is assumed that base-point scheduled generation is committed to meet the hourly average load plus hourly transactions. All deviations from the hourly schedule, then, fall into the load following bin.

The objective is to define an algorithm to compute the flexible generation required each hour to compensate adequately for the actual load from the hourly schedule. The algorithm must be based on information available to operators at the time that these short-term plans for operating reserves are being made.

Assessing deviations from the hourly average value has an advantage in that the flexibility requirement is symmetrical, rather than dependent on the load trend. This is also useful at higher penetrations of wind generation, where the direction of the control area demand may be less predictable than with load alone.

Using ten-minute average load data, a rule is devised to calculate the range over which generation must be moved inside the hour to follow the load deviations from the hourly average. The appropriate factor can be determined through experimentation.

The profile varies by hour, but over the course of the year has some average value.

Figure 7 shows how this works for a typical period out of the sample load data.

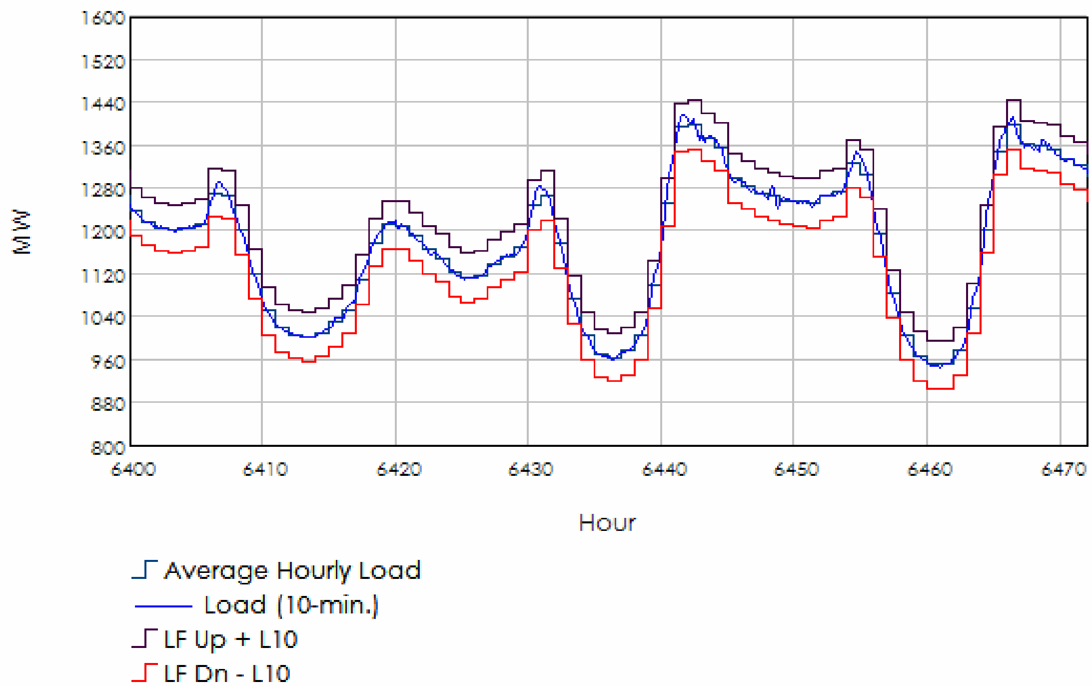

Figure 7.

From that baseline, the next objective is to devise a new rule that works with wind generation on the system. In essence, there must be enough load following capability to encompass the net deviations of load and wind generation at ten minute intervals. Initially it is assumed that wind generation can be forecast perfectly, so that the hourly average value from which the deviations are computed is the net of the hourly average load and the hourly average wind.

The amount of wind generation change over an hour is selected as the metric for characterizing wind generation variability. There most certainly are others that could be developed, such as using statistics of wind generation variability at the ten-minute resolution, but the selected approach lends itself well to characterization from the data at hand.

Using the hourly average wind generation data, the variability over one hour (i.e. change in average production from one hour to the next) is computed for ten deciles of production. Results for wind data developed for another project are shown in Figure 8

The curves show that the maximum variability occurs in the mid-range of the aggregate nameplate rating for the scenario.

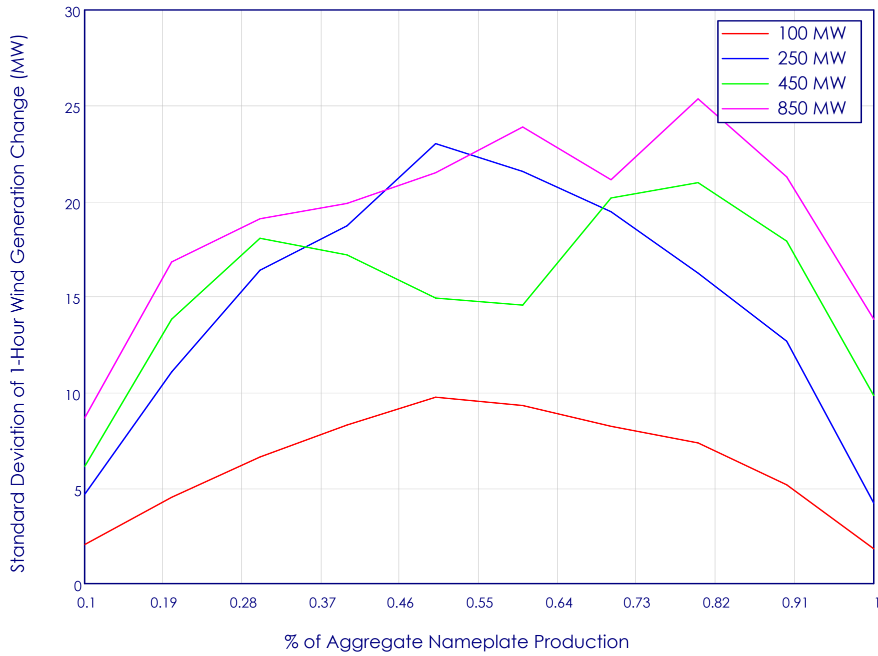

Figure 8.

To facilitate the application of the rule on an hourly basis, the empirical results from Figure 8 are approximated as quadratic expressions, with the input to the expression being the current hour average production. In this first example, it is assumed that the reserve planning for the hour is performed just prior to the start of the hour, so that the average production is from H-1 and the amount of change predicted for H.

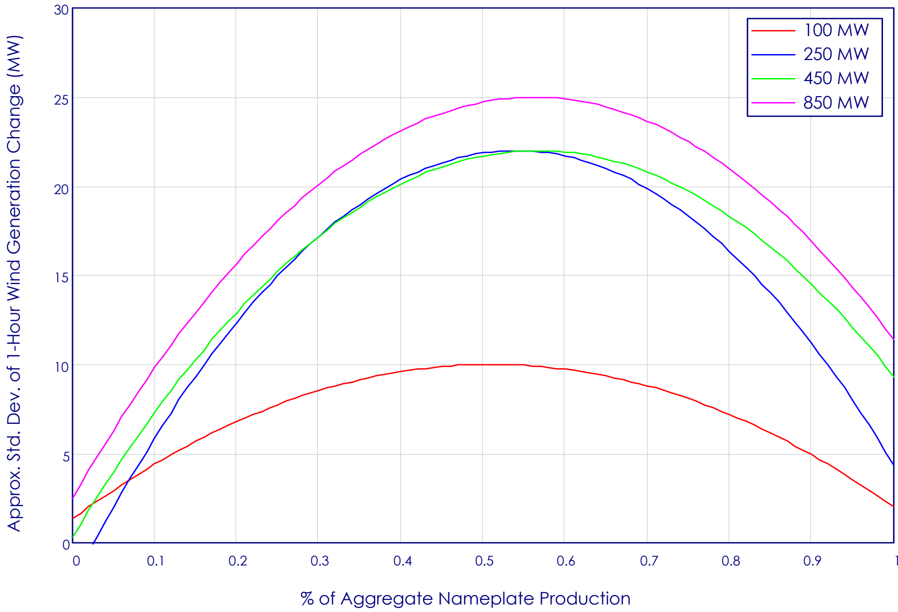

Figure 9.

The quadratic expressions are:

$$f1'(x) := 10 - \frac{(x-51)^2}{300}$$

$$f2'(x) := 22 - \frac{(x-135)^2}{750}$$

$$f3'(x) := 22 - \frac{(x-255)^2}{3000}$$

$$f4'(x) := 25 - \frac{(x-450)^2}{9000}$$

where f1\` through f4\` correspond to the 100 MW, 250 MW, 450 MW, and 850 MW scenarios respectively.

The load following rules for each wind scenario are of the form

$$F1_h := F0_h + 1.0 \cdot f1'(HWind1_{h-1})$$

$$F2_h := F0_h + 1.0\, f2'(HWind2_{h-1})$$

$$F3_h := F0_h + 1.0 \cdot f3'(HWind3_{h-1})$$

$$F4_h := F0_h + 1.0 \cdot f4'(HWind4_{h-1})$$

where the variable in the expression is the current hour average wind generation (h-1 because we are planning for hour h), the quadratic constants are from the empirical analysis described previously, and F0 is the load following requirement for load alone, calculated previously

The coefficient k is adjusted so that the number of CPS2 "violations" is the same as for the case with no wind. Running these experiments for each wind generation scenario, it was found that a coefficient of 1.0 (as shown) provided about the same level of performance for each wind generation scenario.

Figure 10 depicts typical hourly load following "bands" shown with average hourly and ten-minute control area demand. While most ten-minute values are well inside these bands, a few violations can be seen in this 72-hour record.

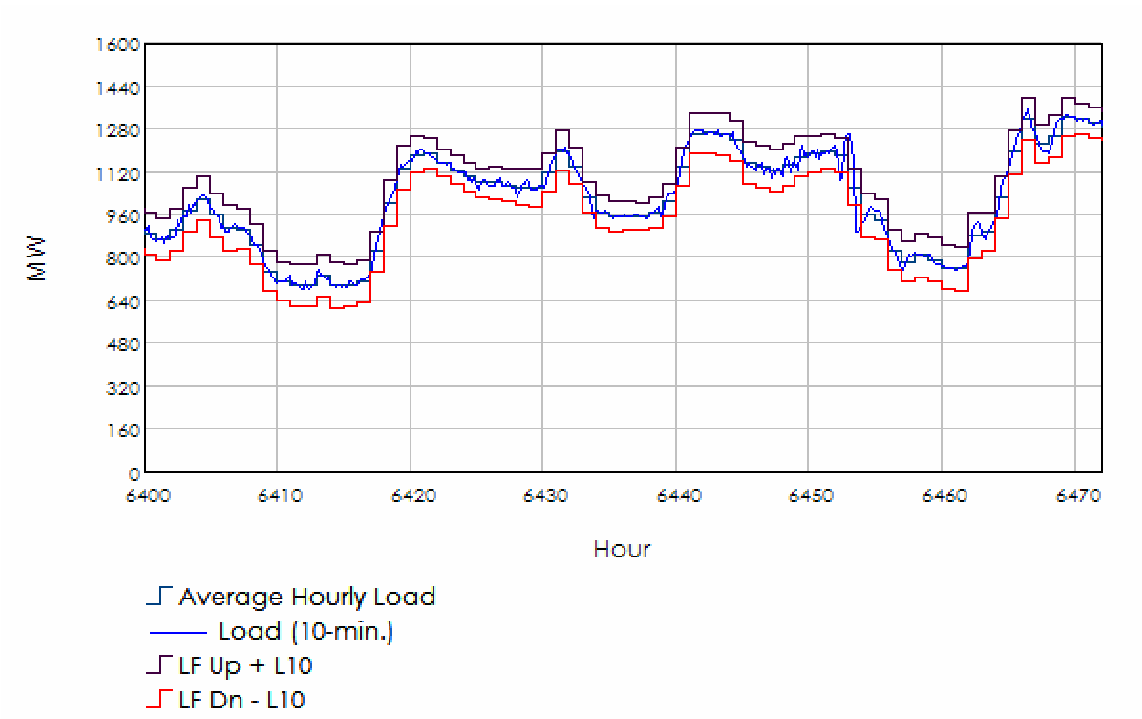

Figure 10.

Uncertainty Impacts on Reserve Requirements

The previous analysis assumes that the reserves for the hour are planned on the basis of perfect knowledge of the next hour average load and wind generation. This is the situation with the minimum uncertainty, and relates mostly to the real-time operation of the system to compensate for inside-the-hour variations from some constant average value. In reality, there are operational decisions made some hours prior to this hour that will affect the generation flexibility that is needed to manage the control area.

If reserves must be allocated an hour or more before the operating hour, the known wind generation at that time may be substantially different than in the hour in question. This could impact the projected variability, as it is a function of the current production level. However, since the variability curves (Figure 8 and Figure 9) do not change dramatically with small changes in production level, the error here would be slight.

Larger impacts stem from decisions made based on short-term forecast information. If the window for hourly transactions closes one hour prior to the hour, it is necessary to cover deviations (i.e. forecast error) in the average hourly load net wind from the forecast hourly average load net wind (Figure 11). These deviations are covered by internal generation capacity which has been set aside for the hour in question since there is no other alternative. The capacity must be moveable in either direction, since the sign of the forecast error is not known. The deviation is constant through the hour in question and is actually an offset in the operating position (Figure 12). To cover the deviation, a resource must be scheduled at an operating point for the hour different than what was planned when setting up the hourly schedules. This action is not really following the load, but rather addressing a energy deficit or surplus from schedule. If there are not options for transacting this error with the market or other control errors, generation capacity must be reserved to make this adjustment.

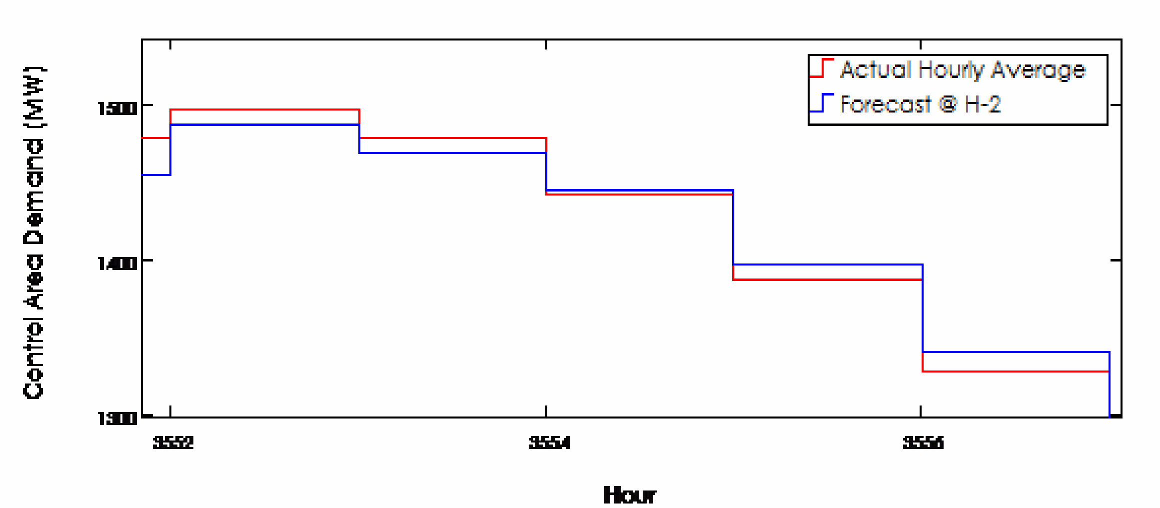

Figure 11. Actual and forecast hourly average values. Short-term forecast is made 1.5 hours prior to the start of the subject hour.

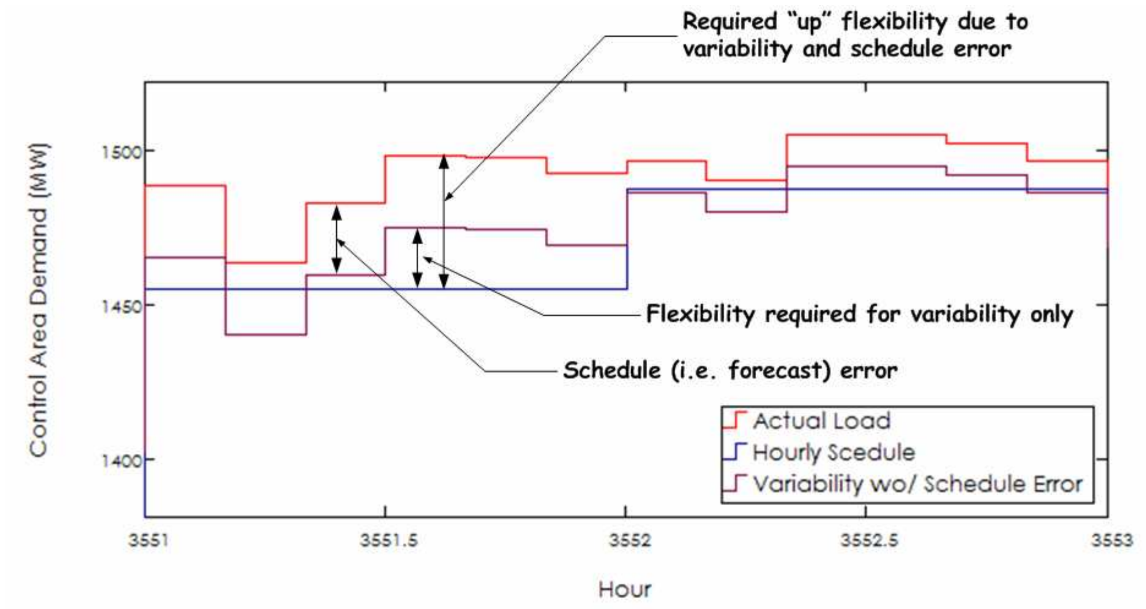

Figure 12. Additional intra-hour flexibility requirements due to schedule error bias.

Schedule deviations are a consequence of the net of short-term load and wind generation forecast errors. Some control areas augment their hourly reserves to insure that enough controllable capacity is allocated to cover the shortfall or be turned down if there is surplus. The schedule deviation will be larger with wind generation. An approach similar to that used to calculate incremental regulation and load following reserves can be employed to determine how much additional capacity must be allocated to cover incremental forecast error. For this example, it is assumed that in-the-day hourly transactions must be completed two hours before the subject operating hour. The error in a persistence forecast for wind generation over a two hour horizon is calculated from the hourly wind generation data and summarized in Figure 13. Note that the standard deviations here are larger than for the 1-hour persistence forecast (which would correspond to Figure 8 and Figure 9), illustrating the relatively rapid degradation of the persistence assumption over longer time frames.

Load forecast errors also contribute to the schedule deviations. In the illustration to follow, it is assume that the MAE (mean absolute error) of the two hour-ahead load forecast is a normally distributed random variable with a standard deviation of 1.25% which results in a mean absolute error of 1.0%. Further, it is assumed that the load forecast error is uncorrelated with the short-term wind generation forecast error.

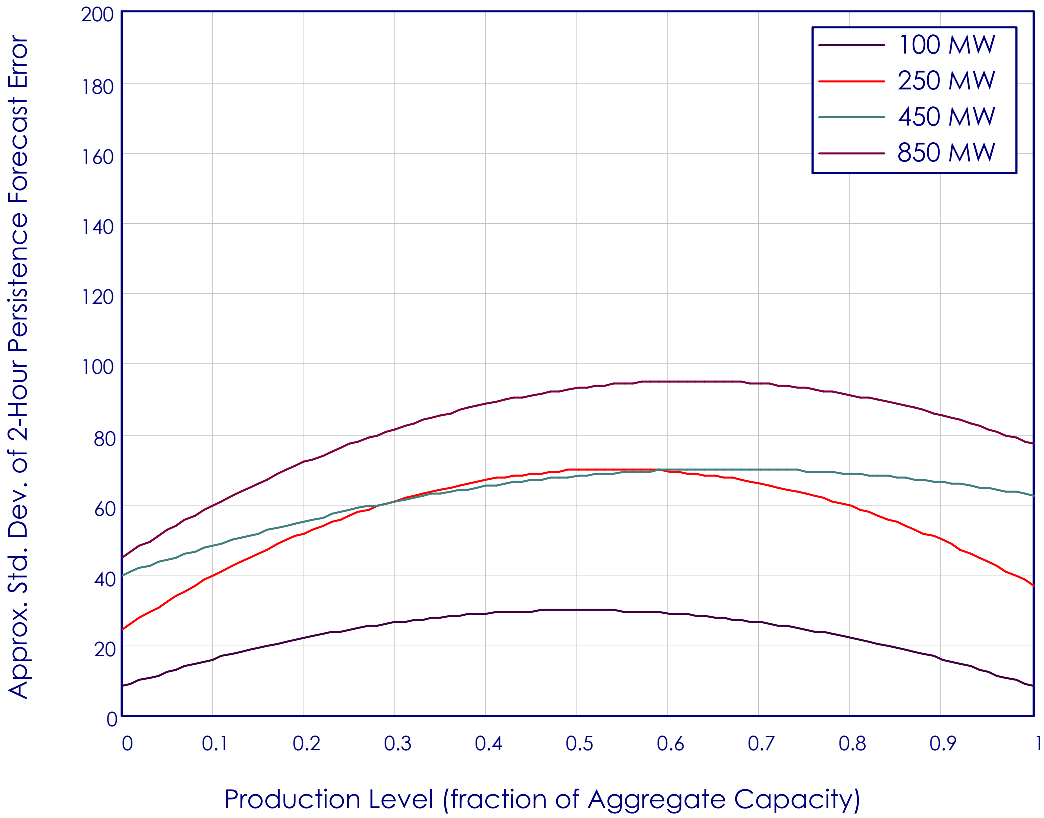

Figure 13: Standard deviation of persistence forecast error over a two hour horizon for the four wind generation scenarios.

Quadratic formulas for the curves of Figure 13 were added to the equations for hourly reserves, and the coefficients adjusted to achieve the same control performance as for load variability alone.

The new load following equations that consider the lead time for hourly transactions and the associated uncertainty in both load and wind generation are shown below:

$$F0'_h := F0_h + 0.8 \cdot \sigma_{stlfe}$$

$$F1'_h := F1_h + 0.8 \cdot FE1\left(HWind1_{h-2}\right) + 0.8 \cdot \sigma_{stlfe}$$

$$F2'_h := F2_h + 1.8 \cdot FE2\left(HWind2_{h-2}\right) + 0.8 \cdot \sigma_{stlfe}$$

$$F3'_h := F3_h + 1.8 \cdot FE3\left(HWind3_{h-2}\right) + 0.8 \cdot \sigma_{stlfe}$$

$$F4'_h := F4_h + 2.0 \cdot FE4\left(HWind4_{h-2}\right) + 0.8 \cdot \sigma_{stlfe}$$

where

F0 = the reserve requirement for managing intra-hour variability only (or F1, F2, F3, F4 for load net wind variability only)

σ_{stlfe} = standard deviation of the short-term load forecast error

FE"x" = function describing standard deviation of short-term wind generation forecast error as a function of production level, where "x" is wind generation scenario 1, 2, 3, or 4. This is to the total hourly up/down reserve requirement needed to compensate for both the intra-hour variability and schedule deviations from short-term load and wind generation forecast error.

As done with variability, the coefficients on the terms representing the forecast errors are adjusted so that the desired percentage of ten-minute deviations from the hourly average can be compensated to within the balancing authority's L10 value.

Just prior to the operating hour, the direction of the forecast error will be known. Intra-hour variability, as computed earlier in the study, must still be covered and is not affected by the forecast error. So, it seems that the real-time operators would know at the beginning of the operator hour how the scheduling error would impact the reserve requirements. If there is additional energy to be provided to cover the forecast error, the capacity set aside to move up would be used, with no need to retain the downward movement capability. The operating plan for the hour must be sufficient to cover both the up and down side of the forecast error.

Because it is an offset in the flat schedule for the hour, there is minimal intermingling between the component required for managing variability and that set aside to cover schedule error.

Mapping to PROMOD IV Reserve Categories

The preceding analysis provides a method for characterizing variability and uncertainty in terms that relate to operating reserve practice. To utilize them for long-term production simulations, it is necessary to map them onto the reserve categories defined by the particular program.

EnerNex has experience with PROMOD from the 2006 Minnesota Wind Integration Study. It was found that the translation of results derived from the procedure described above was not straightforward. However, after consultation with MISO, the project sponsors, and New Energy Associates, a satisfactory representation of the incremental reserve requirements was developed.

Approach for Support of WAPA Wind Hydro Feasibility Study

Provided that adequate wind generation and balancing authority load data are available – in both chronological extent and temporal resolution – application of the techniques described in the previous sections is neither labor- or computation-intensive. EnerNex has found from previous wind integration studies that the key to deriving satisfactory results from these techniques is a thorough understanding of the operating practices and reserve allocations methodologies in use by those involved in the study. There are numerous opportunities for adjustments and modifications, and if and how those used will depend on the perspective of those that understand the operation of the existing system.

We propose to conduct this investigation using the following approach:

- Upon receipt of the wind generation and load data, some preliminary analysis will be conducted, then summarized and provided to the client. Questions and critical issues will also be identified in this transmittal.

- A conference call will be planned and executed, during which answer to some of the general questions may be found. For others, key personnel will be identified to assist with resolution.
- Feedback from the teleconference will be incorporated into the analysis, from which will come the data to be used as input to PROMOD IV for the hourly production simulations.
- Other scenarios will be analyzed as appropriate. If these are markedly different than the first scenario – namely, if the penetration reaches very high levels – additional consultation with study participants may be necessary.