Operating Reserve Implication of Alternative Implementations of an Energy Imbalance Service on Wind Integration in the Western Interconnection

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Operating Reserve Implication of Alternative Implementations of an Energy Imbalance Service on Wind Integration in the Western Interconnection

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***Abstract*— During the past few years, there has been significant interest in alternative ways to manage power systems over a larger effective electrical footprint. Large regional transmission organizations in the Eastern Interconnection have effectively consolidated balancing areas, achieving significant economies of scale that result in a reduction in required reserves. Conversely, in the Western Interconnection there are many balancing areas, which will result in challenges if there is significant wind and solar energy development in the region. A recent proposal to the Western Electricity Coordinating Council suggests a regional energy imbalance service (EIS). To evaluate this EIS, a number of analyses are in process or are planned. This paper describes one part of an analysis of the EIS's implication on operating reserves under several alternative scenarios of the market footprint and participation. We improve on the operating reserves method utilized in the Eastern Wind Integration and Transmission Study and apply this modified approach to data from the Western Wind and Solar Integration Study.**

***Index Terms*—Wind energy, balancing area, wind integration**

I. Introduction

The anticipated increase in variable generation in the Western Interconnection over the next several years has raised concerns about how to maintain system balance, especially in smaller Balancing Authority Areas (BAAs). Given renewable portfolio standards in the West, it is possible that more than 50 gigawatts (GW) of wind capacity will be installed by 2020. The consequent increase in variability that must be managed by the non-wind generation fleet and responsive load makes it attractive to consider ways in which BAAs can cooperate to increase operating efficiency. Our analysis considers several alternative forms of an Energy Imbalance Market (EIM) that has been proposed in the non-market areas of the Western Interconnection. Although the analysis presented here focuses on high penetrations of wind energy, it can easily be adapted to solar data and combined contributions from wind and solar energy.

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II. Data

We used data from the recent Western Wind and Solar Integration Study (WWSIS), managed by the National Renewable Energy Laboratory (NREL) on behalf of the U.S. Department of Energy (DOE) [1]. The study outlined several alternative build-out scenarios of wind plants: (a) the “in area” scenario, which assumes all renewable portfolio standards (RPS) requirements are met by resources within the state; (b) the “mega-project” scenario, which locates wind plants based on wind regime quality, as measured by the annual capacity factor; and (c) the “local priority” case that blends (a) and (b). For this study, we utilize scenario (a). Our method can easily be applied to the other scenarios or to entirely different mixes of wind and/or solar energy. The wind energy penetration from our selected case is 30% of all electricity within the WestConnect footprint and 20% of all electricity in the remaining Interconnection.

3Tier Group developed a large wind speed and wind power database using a Numerical Weather Prediction (NWP) model applied to the West. Because the model allows the re-creation of the weather at any time or space, wind speed data were sampled every 10 minutes for a 3-year period on a 2-km spatial resolution at representative hub heights for modern wind turbines. The resulting data set does a good job of capturing the chronological behavior of the wind that would be seen at locations around the West. The high-resolution data set was then used to construct the various wind scenarios described above.

Load profile data from 2006 was chosen from Ventyx Velocity Suite and was increased to represent 2017 loads. The load information was only available at an hourly resolution. To provide adequate temporal resolution to observe diversity effects and to match the resolution of the wind data, 10-minute data were synthesized from the hourly load data. The intra-hour variability was statistically characterized using multiple datasets from BPA and other eastern interconnection sources. The load-following trend was removed from the datasets, and the remaining variability was characterized as a normally distributed random variable whose mean is 0 and standard deviation has a non-linear relationship with the size of the balancing authority. That relationship was also deduced from analysis of the intra-hour data.

The 2006 wind data set was paired with the 2006 load shape so that the common weather impacts on load and wind would be consistent. We aggregated the data into regional footprints:

Columbia Grid, Northern Tier Transmission Group, WestConnect, and British Colombia. Other areas within the Western Interconnection (California and Alberta) were not modeled because markets are already in place in those areas and they likely would not participate in the EIM analyzed in this paper.

The NWP model of the Western Interconnection contained geographic and temporal seams that were not possible to resolve. This resulted in unrealistic wind energy ramps near the temporal boundaries, which occurred every 3 days. To make the reserves and ramping analysis complete, a continuous annual record was needed, so a method to smooth those ramps below statistical significance was required. To do this, the wind data were analyzed in detail surrounding the anomalies. The time range where they occurred and the magnitude characteristics were observed. Statistics for similar time periods not affected by the anomaly were computed. Several moving average filters were designed to push the magnitude of the anomalies below a threshold consistent with statistics from the non-affected times.

III. Overview of the Proposed Efficient Dispatch Toolkit and Energy Imbalance Market

In the Western Interconnection, areas outside of California and Alberta do not presently have a common energy market, although there is bilateral transaction activity in the region. The Seams Issues Subcommittee of the Western Electricity Coordinating Council (WECC) is currently investigating an Efficient Dispatch Toolkit (EDT) that would achieve many of the benefits of a large-scale energy market but without a coordinated unit commitment or regulation market.

The proposed EDT would use two primary tools. An Enhanced Curtailment Calculator (ECC), which can prioritize and allocate transmission service curtailments based on service priority for power flow impacts on the grid, will evaluate tagged and un-tagged flows (most deliveries inside balancing areas are not tagged). The ECC would pass relevant curtailment information to the second tool, the EIM.

The EIM uses a security-constrained economic dispatch to provide two functions:

- Balancing service: This service re-dispatches generation to maintain the balance between generation and load. For deliveries scheduled in advance, the effect is that the market supplies deviations from schedules in generator output and errors in load schedules.
- Congestion re-dispatch service: This will re-dispatch generation to relieve overload constraints on the grid. Information provided to the EIM from the ECC ensures correct allocation of the costs of re-dispatch service.

The current approach that is used by WECC Balancing Authorities (BAs) for balancing services comes from the Federal Energy Regulatory Commission (FERC) Pro Forma Tariff Schedules 4 and 9. The proposed EIM replaces part of the BA services and results in a "virtual consolidation" due to a wide-area security-constrained economic dispatch that covers imbalances. The congestion re-dispatch service is new to the non-market portions of WECC.

The EIM design includes a feature different from most regional markets in the United States where internal resources are subject to a "must offer" requirement. Instead, the default operating assumption is that each market participant provides sufficient resources to cover its own obligations (as is the case today) and the regional economic dispatch is provided by any resource that voluntarily offered responsive capability and which is cleared by the security-constrained economic dispatch process. Most transmission service deliveries would continue to use traditional reserved transmission service, but the EIM would not use pre-reserved transmission. Instead, the EIM flow would receive the lowest transmission service curtailment priority. By this mechanism, EIM flows would not displace reserved transmission service.

Unlike other regional markets where transmission service for market delivery is provided under a regional network service tariff, the EIM flows would pay an imputed service compensation after-the-fact to participating transmission providers. At this stage of development of the EDT toolkit, the specific terms for the transmission service revenue target and revenue allocation among participating transmission providers have not yet been established.

The EIM function adds some operational steps to the current practices used in the Western Interconnection today. Functionally, the operating steps for the proposed EIM track closely with the operating process established in the Southwest Power Pool (SPP) in their Energy Imbalance Service Market. Figure 1 illustrates the timeline for operation of the proposed EDT toolkit.

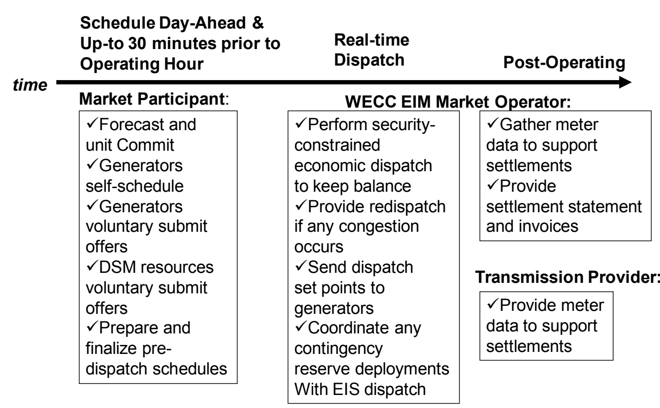

Figure 1. Operation timeline for the EIM toolkit.

The EIM would effectively implement one form of a virtual BA across the Western Interconnection (California and Alberta would not be included because they already have energy markets). Imbalances would be netted out, much as they would be in a single BA. As proposed, the EIM does not result in a coordinated unit commitment, nor does it pool regulation, which remains a service at the local balancing area level. However, the netting of energy imbalance, which would include impacts of load and wind, is expected to be significant. FIGURE 2 illustrates the concept, with each of the small bubbles representing a single BA. The arrows between the BAs indicate bilateral tagged energy flows that would not be precluded in the EIM. However, under the EIM, only the footprint net imbalance must be managed, resulting in less "pent-up" variability within the local BAs and less required ramping across the footprint.

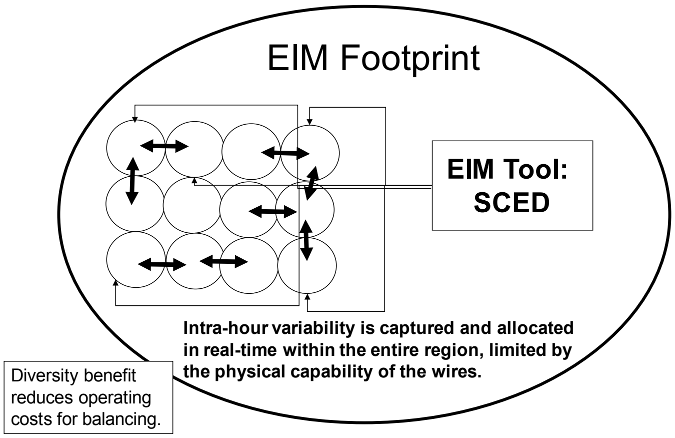

Figure 2. The EIM would effectively pool variability within the operating footprint, similar to a single BA.

IV. Alternative Market Scenarios

We analyzed a large number of possible market footprints and variations on participation levels, based on current discussions with WECC.

Table 1 shows the combinations we used. Although the EIM may cover all of the non-market areas of the Interconnection, there may instead be regional implementations of the market that correspond to the regional transmission planning groups, which include Columbia Grid, WestConnect, and Northern Tier Transmission Group. For our study we did not include wind in British Columbia because no wind data were available. Federal Power Marketing Agencies such as the Bonneville Power Administration (BPA) and Western Area Power Administration (WAPA) may not participate in the EIM because of various potential institutional constraints. We therefore constructed cases that excluded one or both of these entities as variations from the all-inclusive participation cases. The full footprint includes all of the Western Interconnection except for Alberta and California.

The proposed EIM would operate at the 5-minute level, aggregating energy settlements to hourly; however, our analysis evaluated alternative dispatch intervals of 10 minutes, 30 minutes, and 60 minutes because of data limitations. As discussed in [18], faster markets improve access to generation that may be available to alter its output, whereas slower markets restrict units on economic dispatch so that they cannot respond to demand changes within the dispatch period. Our 10-minute analysis understates the benefits of the actual 5-minute EIM. Table 2 illustrates the scheduling and dispatch intervals along with forecast assumptions for wind.

Table 1. Scenario Descriptions

	Market Footprint		
	Full Footprint	**Regional**	**Business as Usual (BAU)**
Wind and load in same BA			
Full participation	X	X	X
Excludes BPA	X	X	
Excludes WAPA	X	X	
Excludes both WAPA and BPA	X	X	
Wind in separate BA from load			
Full participation	X	X	X
Excludes BPA	X	X	
Excludes WAPA	X	X	
Excludes both WAPA and BPA	X	X	

Table 2. Alternative Scheduling/Dispatch and Wind Forecast Assumptions

Schedule	**Dispatch Interval**	**Forecast Set Time**
10m	10 minutes	10 minutes prior
30m	30 minutes	40 minutes prior to start of hour and half-hour (40 minutes lead)
60m	60 minutes	40 minutes prior to start of the hour

V. Variability Analysis

Larger operating footprints improve the ability of the system to respond to variability [2] [3]. This occurs for two reasons: (1) Pooling of variability of loads and wind generation increases diversity, which reduces the overall per-unit variability, and (2) a broader resource mix increases ramping capability linearly. The result is that aggregation provides an increased ability to manage variability, which itself is reduced with aggregation. This principle can be applied to many facets of power system operation and is one driver for the formation of reserve-sharing pools that reduce the total level of contingency reserve needed to maintain reliability.

Figure 3 shows the peak load and wind coincidence for all of WECC and the four regions. Aggregation provides a host of benefits for load as well as for wind. Aggregation reduces the peak capacity requirements for load alone. Coincident peak load is 6.2% lower for WECC than the sum of the non-coincident peak loads which each BA must support on its own.

Minimum loads are also improved (raised) through aggregation: 8.6% for WECC and 17.2% for Columbia Grid. Load factor is 3.9% better for the aggregated WECC (62.9% vs 59.0%).

Aggregation also benefits wind. Peak WECC wind is reduced by 15.3% through aggregation. WECC-aggregated minimum wind is 420 megawatts (MW), compared with zero to 43 MW for the individual subregions. WECC wind capacity factor increases by 6.1% with aggregation. Aggregating wind also reduces the maximum wind penetration. One BA in WestConnect (WAUW) has a maximum 10-minute wind penetration of 784%, which is reduced to a maximum of 95% for the aggregated WestConnect and a maximum 62% for aggregated WECC.

VI. RESERVE ANALYSIS

The increased variability and uncertainty that wind will bring to the power system must be managed through a combination of flexible generation and responsive load. Together, these can contribute to the operating reserve that is available to help manage the wind and load variability. A methodology was developed to estimate the increased requirements for regulation with wind variability in the Eastern Wind Integration and Transmission Study (EWITS) [4]. The EWITS methodology focused on fast schedule updates of 10 minutes or faster. For the purposes of this work, that method was extended to cover hourly schedule updates as well.

Short-term variability is challenging because it is difficult to fully anticipate the scheduling changes and fluctuations must be covered with reserves. In a system with 10-minute markets or schedule updates, the best one can do is forecast a flat value for wind output for the next interval based on the past 10 to 20 minutes. The wind varies on that time scale, and an understanding is needed of how it will vary during the forecast interval.

Figure 4 and Figure 5 illustrate how the forecast error is calculated for both 10-minute and 1-hour schedules. The forecast error is the difference between the actual data and the forecast value.

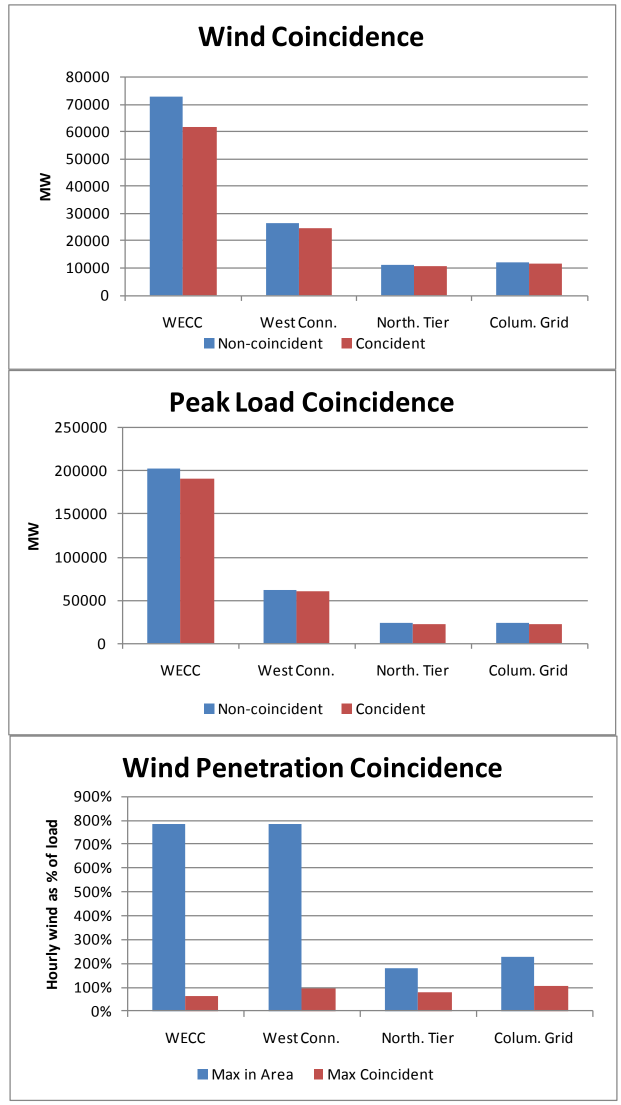

Figure 3. Coincidence of wind, load, and hourly penetration.

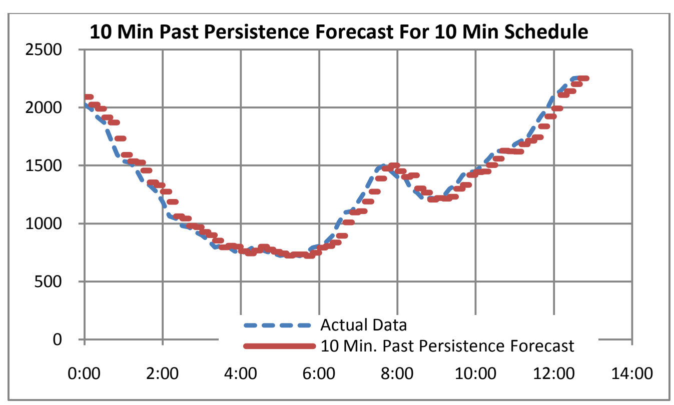

Figure 4. Forecast for 10-minute schedule.

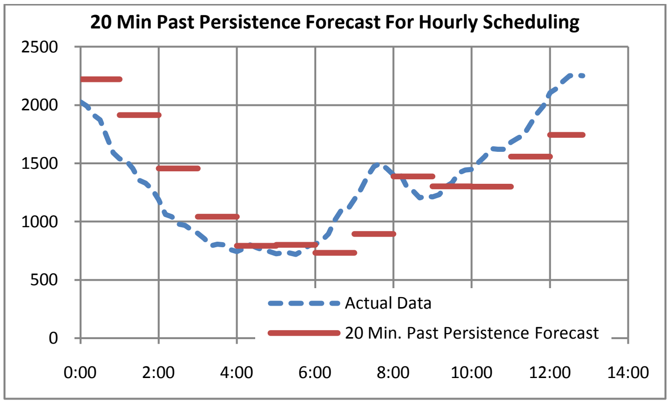

Figure 5. Forecast for 1-hour schedule made at 40 minutes prior to the beginning of the operational period.

With a statistical approach that is based on detailed wind and load and forecast data, an estimate of the required reserve can be calculated based on the standard deviation or other variability metric derived from the data.

For our purposes, the reserve requirements are broken down into three classes by the types of resources required to fulfill them.

1. Regulation is required to cover fast changes within the forecast interval. These changes can be up or down and can happen on a minute-to-minute time scale. Regulation requires resources on automatic generation control (AGC).
2. Spinning reserve is required to cover larger, less frequent variations that are primarily due to longer-term forecast errors. Spinning reserve is provided by resources that are spinning or can be available within 10 minutes (quick start). These resources do not necessarily require AGC.
3. Supplemental reserves are used to cover large, slower-moving, infrequent events such as unforecasted ramping events. Supplemental reserve can be made available within 30 minutes.

The variability of wind plant output is a function of its production level. The EWITS method recognizes that the short-term variability in wind plant output and thus short-term forecast error is a normally distributed value over a large geographic footprint. Through analysis, an equation can be written for the standard deviation (sigma) of variability that varies with production level. That equation is derived by analyzing the wind production data over some long period of time (a year or more) and calculating the standard deviation for the variability in various ranges of wind output.

The equation is used to calculate the standard deviation (sigma) of the wind power for each hour. A component to cover load variability is calculated as a fixed percentage of the hourly load. That fixed percentage is calculated based on the load size in the BA as described in the Data section above and is calculated to cover 1 sigma of the load variability. The wind and load components are scaled to 3 sigma and combined as the square root of the sum of the squares. The 3-sigma approach estimates reserve values that will cover 99.7% of all short-term variability for normal distributions; for non-normal distributions, adjustments can be made accordingly. This component must be covered by regulation reserves under AGC.

An additional uncertainty component due to hour-ahead wind forecasting error was calculated as part of the EWITS method. This component is calculated in a similar manner to the short-term forecast error described above, using an equation to describe the standard deviation of hour-ahead forecast error. With that equation, the expected sigma for the forecast error is calculated based on the previous hour's production (persistence forecast). This component helps to insure the system is positioned with enough maneuverability to cover the probable forecast error and divided as 1 sigma assigned to spinning reserves and 2 sigma assigned to supplemental reserves.

VII. Selected Results

A very large number of cases were analyzed for this project. We present some selected results that illustrate the alternative impacts on reserves of several of the key cases.

Per-unit wind variability is reduced with increased geographic diversity, reducing the level of reserves needed to compensate for that variability. Longer-term forecast errors are also reduced by diversity.

Figure 6 illustrates how diversity affects the EIM reserve requirements for the three levels of aggregation. The BAU scenario refers to each BA operating independently. The bars represent the arithmetic sum of all of the BA requirements. The whiskers on the plots show the minimum and maximum values for each parameter. For the regional EIM, the bars represent the sum of the requirements computed at the regional level. The footprint EIM aggregates all of the load and wind into one EIM. As can be clearly seen, the wind regulation reserve requirements for the footprint EIM are less than half those required with BAU. It is interesting to note that the load-only regulation is also reduced significantly by this aggregation. Spinning and supplemental reserve requirements are similarly reduced.

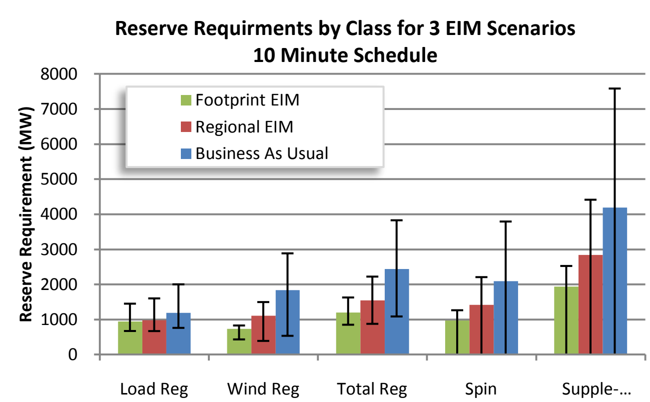

Figure 6. Regulation requirements for various scenarios.

One of the important elements in this work was to understand the effect of non-participation of BAs with large wind production. To do this, cases were run with BPA and WAPA managing their wind individually.

Figure 7 shows the total regulation requirements for the footprint under various combinations of participation. While modest compared to the reductions from BAU, the cases with BPA and WAPA not participating leave a significant amount of reduction unclaimed compared to all BAs in the EIM.

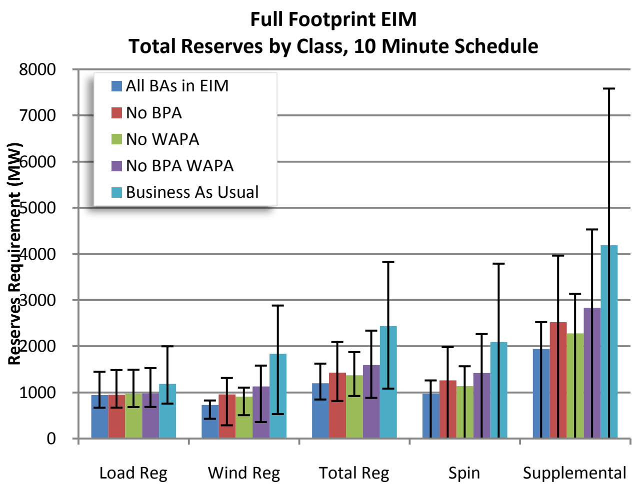

Figure 7. Effect of non-participation by high-wind BAs on reserve requirements.

Another set of configurations that we investigated involved aggregating wind into wind-only BAs that would be responsible for acquiring resources to balance the wind variability without any load-serving responsibility. Figure 8 shows the results of these cases along with the combined load and wind BA cases described above. In the footprint/wind-only case, there is one load aggregation on the full footprint and one EIM for wind combining all of the wind in the footprint. The regional wind-only case creates separate regional EIMs for wind and load, one in each of the regions. Finally, the BAU/wind-only case creates a single wind EIM and models the existing BA structure operating as it does today. The graph shows that any wind-only BA structure will not reduce regulation requirements as much as aggregating load and wind in the same BA structure.

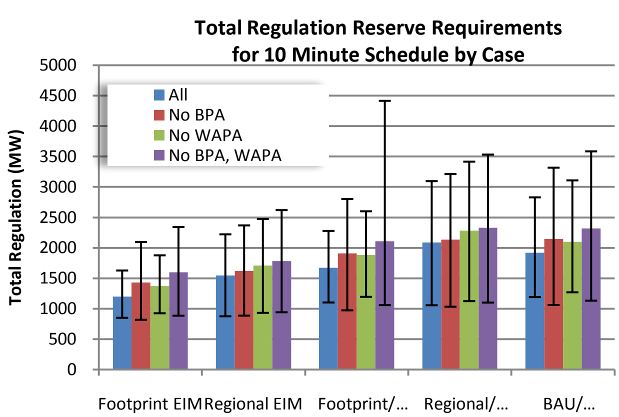

Figure 8. Total regulation requirements for wind-only BA cases.

To understand how often various amounts of regulation are required, we developed a regulation duration plot. Figure 9 shows that plot for the BAU and footprint-wide EIM cases. The plot shows the large decrease in the overall requirements but particularly at the high end of the requirements scale.

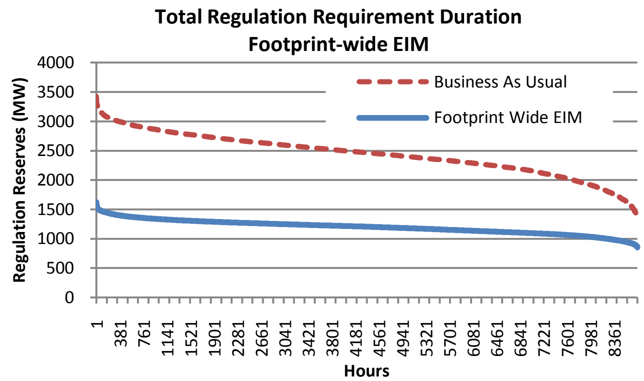

Figure 9. Comparison of footprint-wide EIM to BAU total regulation requirement.

Interestingly, the regulation requirement for the large aggregation is flatter as well as lower than when regulation is supplied for each BA individually. Aggregation is especially effective in reducing the tails events. Figure 10 shows this by plotting the difference in the two duration curves in Figure 9.

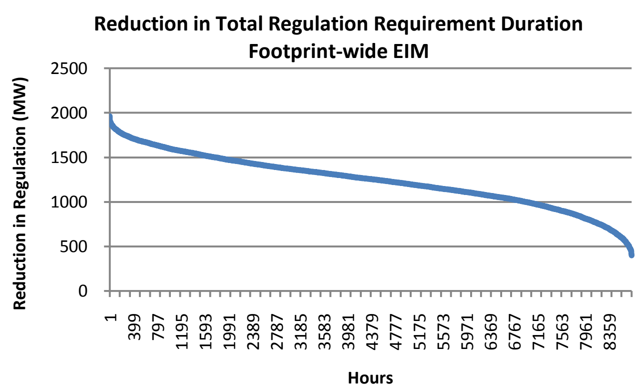

Figure 10. Reduction in total regulation reserve requirements by implementing a footprint-wide EIM.

Both faster scheduling (economic dispatch) and aggregation over a larger area reduce the regulation reserve requirements, as shown in Figure 11. Ten-minute scheduling requires about 29% of the regulation reserves compared to hourly scheduling under all aggregations. Similarly, when all 29 BAs cooperate (All) they need less than half (49% for 10-minute scheduling) of the total regulation compared to BAU, *regardless of the scheduling interval. Implementing both 10-minute scheduling and regional cooperation will reduce the regulation requirement more than seven-fold from current practice: a significant potential savings.*

One of the important elements in this work was to understand the effect of non-participation of BAs with large wind production. To do this, cases were run with BPA and WAPA managing their wind individually. Aggregation helps all participants, and when one entity does not participate, the benefits for all participants are reduced. Failing to participate has a greater impact on the non-participants. As Figure 11 shows, the remaining participants' regulation requirement is reduced to 51% for 10-minute scheduling if either BPA or WAPA does not participate as opposed to 49% if everyone participates. The non-participant's requirement is still 100%, however, so it is the non-participant that loses the most. If neither BPA nor WAPA participates, the remaining BA's regulation requirement is reduced to 53% for 10-minute scheduling instead of 49%. Results are essentially the same for half-hour and hour scheduling.

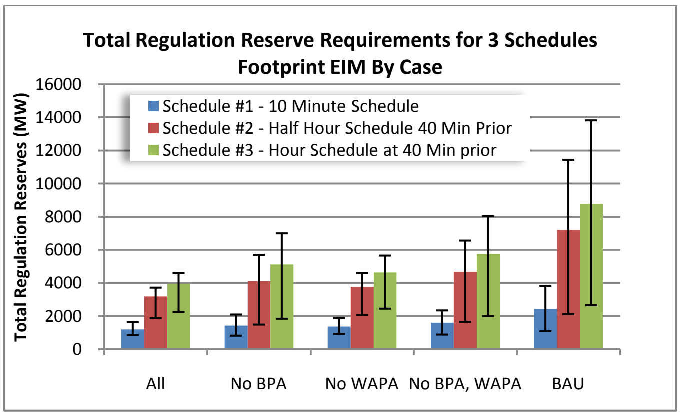

Figure 11. Faster scheduling and larger aggregation greatly reduce the total required regulating reserves.

Ramping requirements are also reduced with aggregation. Figure 12 shows the ramping requirements of wind and net load for both the non-coincident case in which all 29 BAs meet their own requirements and the coincident case in which all 29 BAs cooperate to meet the total system ramping requirement. The figure shows the 90th percentile to match Control Performance Standard (CPS) 2 requirements. Naturally the ramp magnitude increases with longer duration. The curvature indicates that the average ramp rate declines with ramp duration, as expected. Aggregation reduces wind-ramping requirements by around 37% and net-load-ramping requirements by about 25%. Load does not get as much ramping benefit from aggregation because the daily load pattern is highly correlated across the region.

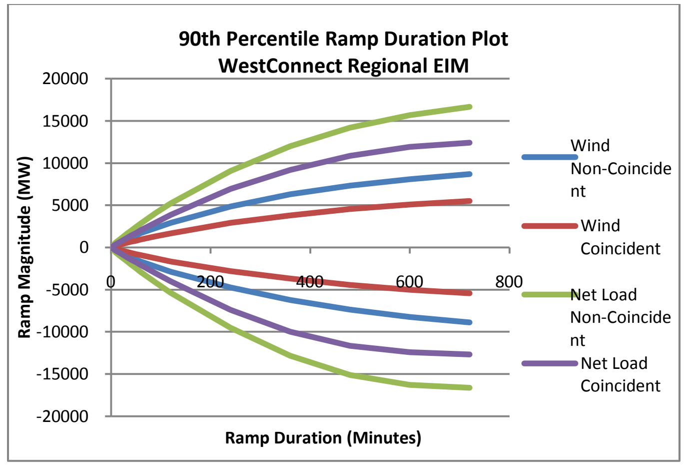

Figure 12. Ramping requirements over all time frames and in both directions are reduced with aggregation for both the wind and net load.

Examining the 99.9th percentile ramping requirements includes rare tails events (Figure 13). These rare ramping requirements are about double the more common, but still relatively infrequent, 90th percentile ramps. The aggregation benefits for both wind and net load are similar (36% and 31% respectively) for these very infrequent ramps.

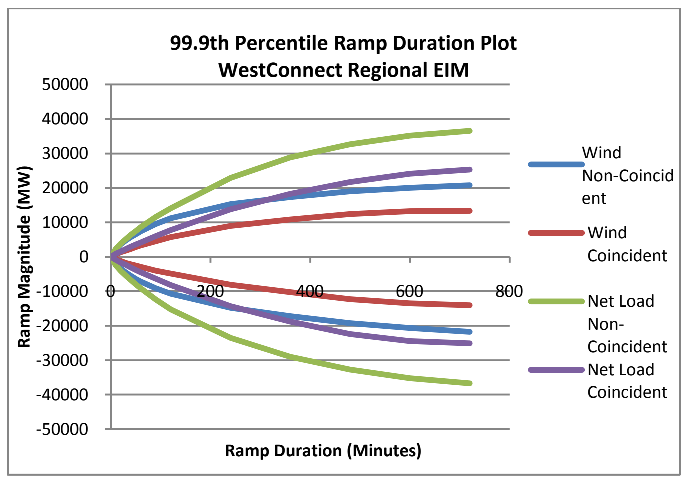

Figure 13. Very rare wind and net load ramps still benefit from aggregation.

Figure 14 directly compares the 99.9th and 90th percentile ramping requirements. Interestingly, the net load and wind curves overlap for the first hour for both the non-coincident and coincident cases. This suggests that load alone has little additional impact for very rare ramps that are shorter than about an hour. Load does have a significant impact for longer ramps extending out to 12 hours. This implies that there are rare days when the day/night swing is unusually large but that even on those days the 1-hour ramp rate is not significantly higher. Still, aggregation continues to greatly reduce the impact of even very rare ramps.

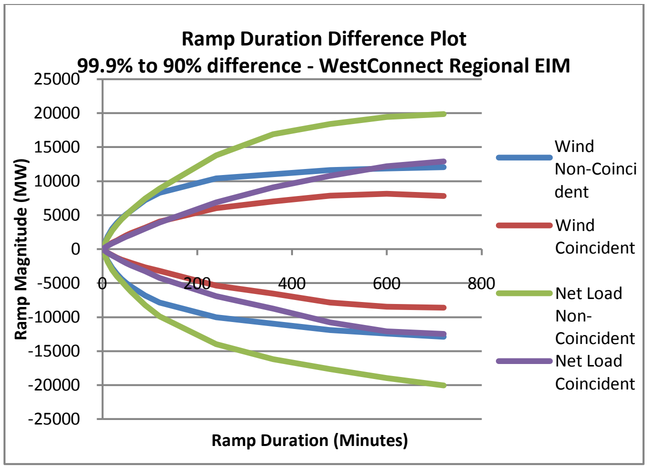

Figure 14. Comparing the 99.9% and 90% ramping requirements shows the impact of very rare ramping events.

VIII. Conclusions

This paper examines alternative implementations of the proposed EIM in the non-market areas of the Western Interconnection. We adapt the reserves method from the EWITS to analyze the implications of these alternative market structures. Although we use standard deviation as the variability metric, our approach could be easily adapted to non-normal distributions and could also be adapted to allow for solar generation, which would be expected to have similar qualitative impacts on variability and uncertainty, and thus reserve requirements.

Based on our analysis, we conclude that full participation of all BAAs would result in maximum benefit across the Interconnection. Lesser participation levels (which include regional implementations of the EIM), various exclusions (BPA and WAPA), and the wind-only BAAs we analyzed will still improve on the BAU but will fail to achieve the maximum benefit of the full participation scenario, especially for the non-participants. We recognize that there may be various institutional impediments to a full EIM implementation, but based on our analysis, the results suggest that potential participants undertake a careful cost-benefit analysis to determine whether it may be economically efficient to implement institutional changes that can help move toward a full EIM implementation.

Finally, we note that the proposed EIM does not consider coordinated unit commitment. We believe that participants, over time, may conclude that some form of coordinate commitment will achieve additional savings, although additional analysis would be needed to determine these impacts.

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