The Impact of Alternative Dispatch Intervals on Operating Reserve Requirements for Variable Generation

Michael Milligan, Jack King, Brendan Kirby, and Stephen Beuning

Abstract—**In the Western Interconnection of the United States, an energy imbalance market (EIM) has been proposed. This would effectively pool the variability of load, wind, and solar generation, and other deviations in generation schedules. The proposed market would perform an economic dispatch every 5 minutes. If implemented, this would be a significant change from the hourly scheduling and dispatch that occurs throughout most of the West. We analyze the impact of alternative scheduling and dispatch intervals on three types of reserves: regulation, following/spin, and following/non-spin. We compare the existing practice of hourly scheduling and dispatch with a 40-minute advance notification with 30-minute and 10-minute scheduling and dispatch. We also analyze the impact of alternative notification periods such as 30-minute scheduling/dispatch with 10, 30, and 40-minute notifications. We find that moving from a 60-minute dispatch to a 10-minute dispatch results in a 70% saving on deployed regulation.**

Index Terms—**Wind and Solar Integration; Scheduling; Economic Dispatch; Energy Imbalance Market;**

I. Nomenclature

WC - WestConnect
WI – Western Interconnection
WECC – Western Electricity Coordinating Council
CG – Columbia Grid
NTTG – Northern Tier Transmission Group

II. 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 Areas (BAs). Given renewable portfolio standards in the West, it is possible that more than 50 gigawatts (GW) of wind capacity will be installed by 2020. Significant quantities of solar generation are likely to be added as well. The consequent increase in variability managed by the conventional generation fleet and responsive load makes it attractive to consider ways in which Balancing Area Authorities (BAAs) can pool their variability and response resources, thus taking advantage of geographic and temporal diversity to increase overall operational efficiency.

There are several approaches that could be taken to implement this type of variability pooling, each of which would involve alternative levels of operational coordination, beyond what is done today. A full pooling of variability could potentially result in fully-coordinated unit commitment, after blending the load and wind forecasts. Closer to real-time, economic dispatch could also be done across the entire electrical footprint. An alternative to this fully coordinated operational case would consist of using existing practice for unit commitment, which is largely uncoordinated between BAAs in most cases, but allowing for economic dispatch over a wide area. We summarize a more detailed report [1]. In this paper, we examine the impact of alternative scheduling/dispatch intervals. We find significant benefit as shorter time steps reduce regulation and following requirements, independent of the overall reduction in variability that results from wide-area pooling.

III. 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) [3]. 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 each 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). Interestingly, there were not dramatic differences in total costs for the different scenarios. For this study, we utilize scenario (a). Our method can 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.

The 2006 time-series wind data set was paired with the 2006 time series load data so that the common weather impacts on load and wind would be consistent, and the load data were scaled by WECC to represent 2017. We aggregated the data into regional footprints: Columbia Grid (CG), Northern Tier Transmission Group (NTTG), WestConnect (WC), and British Colombia. Other areas within the Western Interconnection (WI), California and Alberta, were not modeled because markets are already in place in those areas and they likely would not participate in the initial EIM analyzed in this report. Additional details are described in [1].

IV. Scheduling and Dispatch with the EIM

In the WI, areas outside of the California Independent System Operator footprint and Alberta do not presently have a common energy market, although there is bilateral transaction activity in the region. The WECC Board of Directors and some WECC stakeholder committees are 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 ancillary services 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) and would provide curtailment information for seams coordination and for congestion management. The ECC would pass relevant curtailment information to the second tool, the EIM.

The EIM uses a least-cost, security-constrained economic dispatch to meet the supply obligation of the market footprint. The effect of this dispatch can be characterized by two conceptually distinct services, although settlements in the EIM do not differentiate these services:

1. Balancing service: This service re-dispatches generation every 5 minutes 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.
2. 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 BAAs for settlement of balancing services comes from the Federal Energy Regulatory Commission (FERC) Pro Forma Tariff Schedules 4 (energy imbalance) and 9 (generation imbalance). The proposed EIM replaces part of the BAA balancing services and results in a "virtual consolidation" due to a wide-area security-constrained economic dispatch that covers imbalances. Most BAAs employ security-constrained economic dispatch within their borders today, so the aggregated dispatch at a broader level is not conceptually new. The congestion re-dispatch service, however, is new to the portions of the WI that are not presently operating in areas with modern congestion management practices. The EIM is functionally very close to the imbalance market implemented by the Southwest Power Pool (SPP) Our discussion assumes that the EIM design will not differ significantly from SPP's..

Figure 1 shows the sequence for taking the current system data, calculating the expected conditions and required setpoints for the next interval, communicating those setpoints to generators and responsive loads, and the responsive resources moving to the new setpoints, all in 10 minutes.

Figure 2 shows how the continually repeating process results in a re-dispatch every 5 minutes, using data that are 10 minutes old.

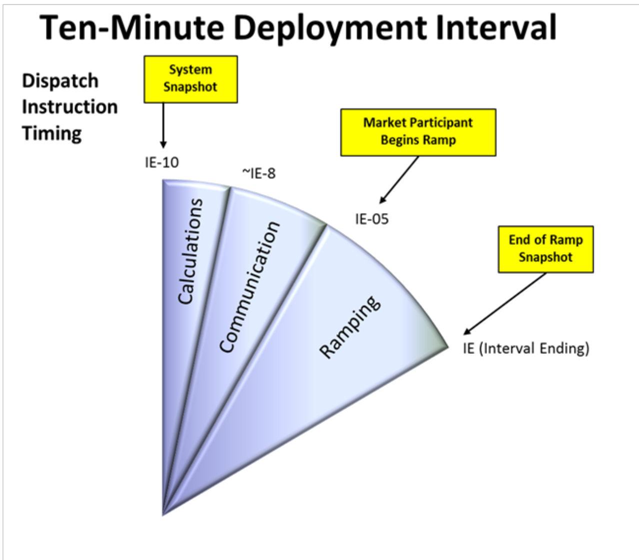

Figure 1 - EIM schedule for calculating setpoints and moving generation within ten minutes.

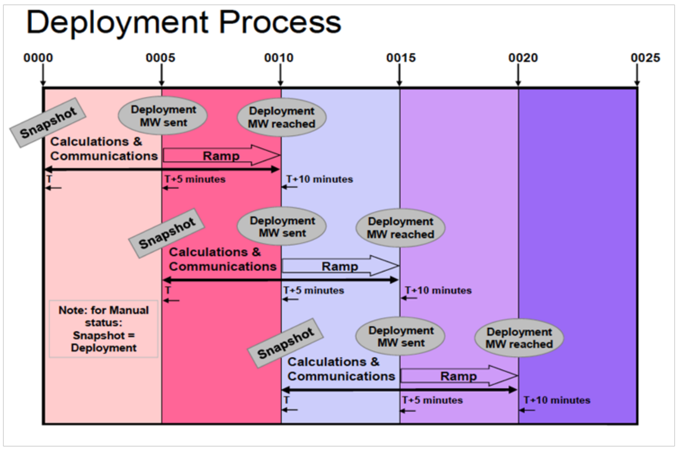

Figure 2 - Continuous dispatch occurs every 5 minutes using data from 10 minutes prior

V. ANALYSIS METHODS

The increased variability and uncertainty from wind and solar power causes an increase in operating reserve requirements that can be met by some combination of flexible generation and responsive load. Together, these resources contribute to the operating reserves available to help balance the wind and load variability. This reserve is calculated dynamically, and is a function of the time-synchronized anticipated variability of the wind power and the load. A method was developed as described in the Eastern Wind Integration and Transmission Study (EWITS) [4]. The EWITS method focused on fast dispatch updates of 10 minutes or faster. For the purposes of this work, that method was extended to cover hourly dispatch updates as well. Although the EIM would operate on a 5-minute period, we used the existing 10-minute data. Since faster ramping would further mitigate the operating reserve impacts, use of the 10-minute data provides a conservative estimate of the impact of shorter scheduling or regional dispatch intervals.

With a statistical approach that is based on detailed wind and load and forecast data, an estimate of the required reserves 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 (generation and responsive load) that are spinning and can fully respond within 10 minutes. These resources do not necessarily require AGC.
3. Non-spinning and supplemental reserves are used to cover large, slower-moving, infrequent events such as unanticipated ramping events. Non-spinning reserve can be made available within 10 minutes and can come from quick start resources and responsive load. Supplemental reserves can be made available within 30 minutes.

We calculated reserves using the method as described in [4], which results in a dynamic reserve for each of the three categories. The method explicitly considers the level of wind output when it determines the likely variability that will occur over the next period or periods, along with the expected uncertainty. Thus, down-reserves, for each of the reserve categories, may be required when wind power is low, but not if it is at or near rated output. Conversely, when wind power is high, up-reserves may be needed, but down-reserves are not. Assessing reserve in this way in integration analysis has become standard practice, although specific methods may vary.

The EIM, as proposed, would carry out a security-constrained economic dispatch every 5 minutes, as described in Section IV. To examine the impact of alternative, shorter dispatch period, our analysis conducts a parametric investigation of alternative time steps. The goal of this analysis is to show that longer time steps, both for dispatch and notification, increase required reserve holdings. Therefore, the fast 5-minute dispatch as envisioned in the EIM will capture a larger benefit than longer time steps would. We stress that these alternative time steps are not part of the EIM; all EIM dispatch is carried out every 5 minutes.

VI. EIM Reserve reductions

There are many possible participation levels for the EIM. At one extreme, the entire WI, excepting those areas already possessing markets (California and Alberta) could participate. Conversely, transmission planning entities in the WI—CG, WC, and NTTG—may implement their own separate EIMs. An additional level of complexity arises because of possible non-participation of the Federal Power Marketing Agencies: the Bonneville Power Administration (BPA) and the Western Area Power Administration (WAPA). Further complicating the level of participation is the possibility that individual BAAs and/or individual generators may choose whether or not to participate. In [1] we discuss these possibilities and provide estimates of some of the more plausible scenarios. In the discussion that follows, we focus on a full-footprint implementation of the EIM, with various combinations of participation from BPA and WAPA. However, in our base case, we show the impact of regional markets to provide some insight as to the differences between these scenarios and full-participation scenarios.

VII. EIM results

Figure 3 shows a summary of the operating reserve requirements across all scenarios analyzed where all BAs are participating in an EIM (BPA and WAPA are included). This demonstrates the similarities between the net load (calculated by taking the difference between load and wind) verses separate EIM structures. Compare, for example, the combined footprint EIM (Footprint EIM) to the separate load and wind EIM (Foot Load/Foot Wind). The regulation requirement for the combined implementation is 1198 MW while the requirement for the separate case is 1672 MW. Also comparing combined regional EIM to a hypothetical regional load/regional wind implementation we see that the total reserves are 2087 MW for the separate EIMs compared to 1547 MW for the load and wind combined scenario, a similar difference. These differences are reflected exactly in the total reserves since the total is the arithmetic sum of the total regulation, the spin and the non-spin.

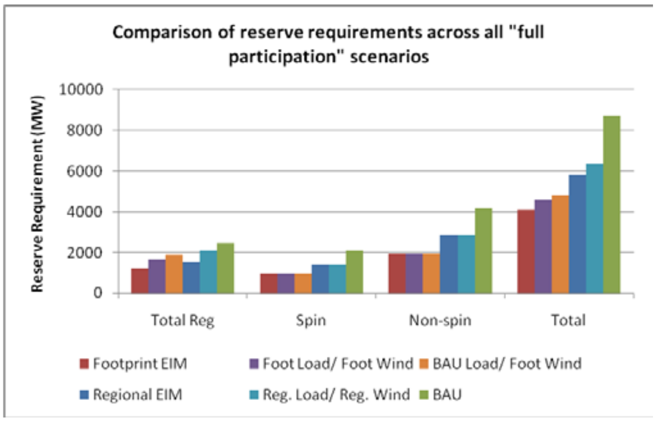

Figure 3 - Reserve requirements across all full participation scenarios

VIII. Effects of faster dispatch

Both faster security-constrained economic dispatch and aggregation of the balancing requirements over a larger area reduce the regulation reserve requirements, as shown in Figure 4. Ten-minute dispatch time steps require about 29% of the regulation reserves compared to hourly dispatch under all aggregations. Five-minute dispatch will require even less. Similarly, when all 29 BAAs participate in the EIM (All) they need less than half (49% for 10-minute dispatch) of the total regulation compared to BAU, regardless of the dispatch interval. Implementing both 10-minute dispatch and regional EIM participation will reduce the regulation deployment more than seven-fold from current practice: a significant potential savings.

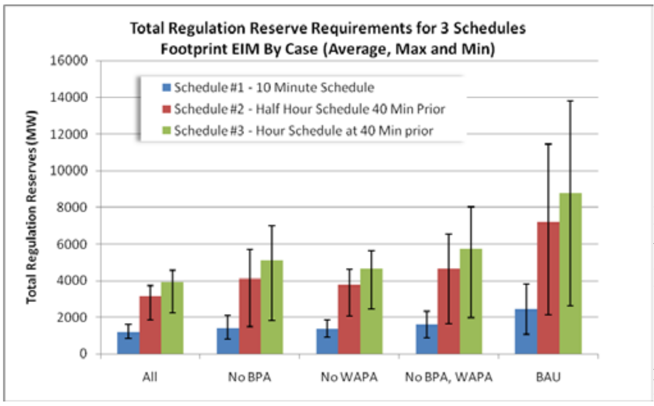

Figure 4 - Faster dispatch and larger aggregation greatly reduce the total required regulating reserves.

Figure 5shows the results for three dispatch and forecast lead time sets based upon the base case, full footprint EIM with all BAs participating. The 30 and 60-minute dispatch each use a 40 minute lead time on the forecast and the 10-minute dispatch uses a 10-minute forecast lead time. The dramatic effect on regulation requirements is very clear. The average total regulation requirement is cut from 3942 MW for a 60-minute dispatch to 1198 MW for the 10-minute dispatch. This represents a savings of 70% on regulation needs and 40% on total reserves (right side columns). All of these savings are from wind related regulation requirements only. In addition, better load forecasts at the 10 minute lead time would improve these results marginally. Spin and non-spin/supplemental are the same for each case because they depend on only hour-ahead forecast errors.

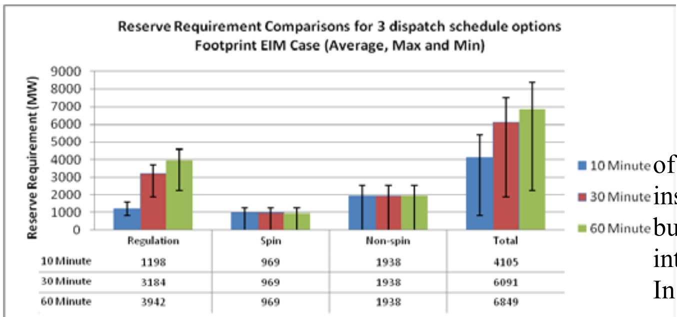

Figure 5 - Effect of forecast lead time and dispatch schedule on reserve requirements

To further illustrate the effect of dispatch interval and forecast lead time, additional cases were run for footprint and regional cooperation. Figure 6 and Table 1 show these results.

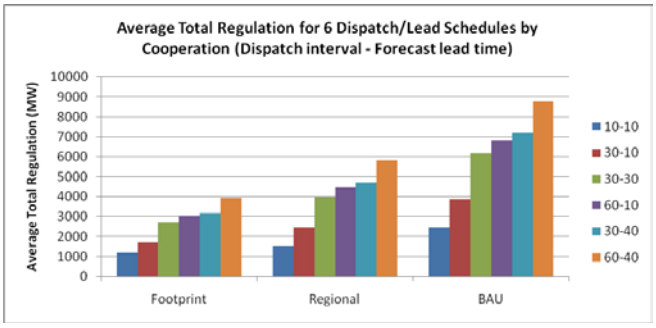

Figure 6 - Comparison of regulation requirements with various EIM participation levels and dispatch/forecast lead times

One very interesting aspect is the relative reduction in reserves regardless of the dispatch schedule. For a given EIM participation scenario (footprint or regional), the reduction in reserves is the nearly same for each of the dispatch/forecast lead time analyzed. A BA can capture the sub-hourly dispatch benefit even if other BAs do not participate in the EIM, which would reduce the aggregation of balancing requirements..

Table 1 - Average total regulation requirements are a constant percentage of BAU relative to various dispatch/lead time schedules

Dispatch-Forecast lead (Min)	Ave. Regulation (MW)			Compared to BAU		
	Footprint	Regional	BAU	Footprint	Regional	BAU
10-10	1198	1547	2440	49%	63%	100%
30-10	1718	2444	3873	44%	63%	100%
30-30	2705	3975	6168	44%	64%	100%
60-10	3027	4453	6831	44%	65%	100%
30-40	3184	4696	7205	44%	65%	100%
60-40	3942	5813	8777	45%	66%	100%

IX. Scheduling vs. Dispatch

BAs that are populated by generation under full control of the system operator may be dispatched at will, absent institutional constraints. In some cases, the BAA owns most, but not all, generation, and can therefore dispatch at intervals that are not prescribed by external considerations. In other cases, scheduled interchange adjustments with neighboring balancing areas may occur only hourly within the BA, causing all intra-hour variability to be covered by internal regulating resources. Such has been the case with BPA, although BPA has reportedly developed new transmission tariff business practices which allow for some schedule adjustments at the half-hour..

BPA operates a large hydro generation portfolio in the Pacific Northwest portion of the United States. There are non-BPA thermal generators within the balancing area footprint. The balancing area also hosts wind generation that is exported outside the BAA under hourly scheduling. [2] analyzed the impact of intra-hourly scheduling compared to hourly exports in the BPA system using data from 2007. They found that, given 2007 wind and load data, the maximum deployed reserve under the existing hourly scheduling paradigm was 451 MW, compared to a maximum of 174 MW with 10-minute scheduling.

The EIM provides a 5-minute economic dispatch for participating entities. As discussed in previous sections of this paper, there is some question regarding the participation of BPA and WAPA in the EIM. As discussed more fully in [1], non-participation of BPA and/or WAPA result in a reduced benefit to the region and no operating reserve benefit to BPA or WAPA if they do not participate.

BPA is experiencing a significant increase in installed wind capacity. As wind installations increase, this will likely, on net, increase the level of wind exports from BPA. Another view of the impact of the non-participation of BPA in the EIM can be obtained by a review of the impact of intra-hour scheduling of exports, using the approach of [2].

As shown in [2], there is no reduction in operating reserve to either the exporting BA or the importing BA associated with maintaining hourly schedules. Within the WI, current scheduling practice among BAs is to utilize a 20-minute window at the top of the hour to ramp generation from the previous hours' setpoints to the new levels for the next hour. This "dance" at the top of the hour causes each BA to move in opposite directions so that the net impact keeps the schedules (which change at the top of the hour) constant. Thus, the export BA moves in an equal and opposite direction to the importing BA over the 20-minute period.

Using methods described in [2], we summarize the impacts of hourly vs. sub-hourly scheduling impacts on BPA, using 2009 public data from BPA (wind and load). Figure 7 provides an illustration from a sample 1-week period that shows the difference in required regulating reserve under an hourly schedule vs. a 10-minute schedule.

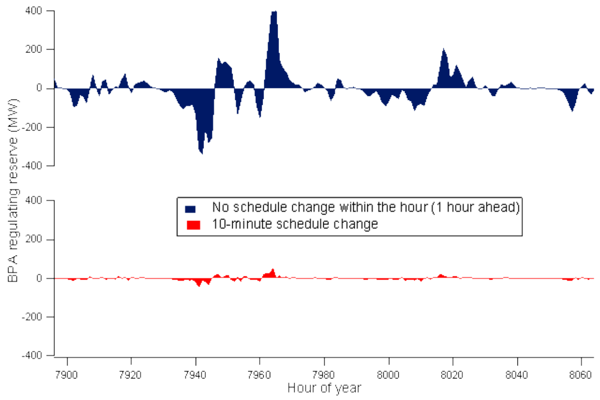

Figure 7 - Example comparison of hourly vs. 10-minute scheduling impacts on regulation for BPA

The previous graph is illustrative, and does not address the annual impact of hourly scheduling. Figure 8 uses a frequency duration curve to show the reduction in the required regulating reserve that would be needed for 10-minute, 30-minute, and hourly schedules.

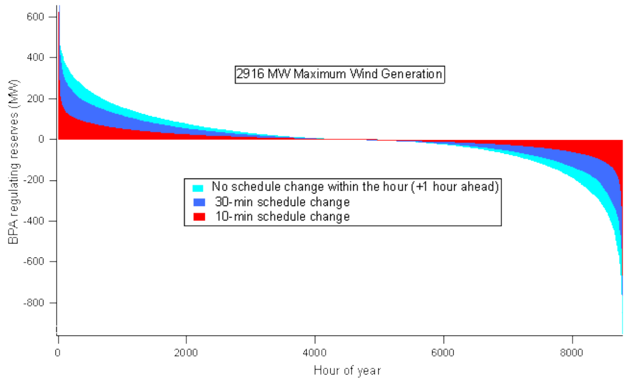

Figure 8 - Annual duration impact of sub-hourly scheduling on BPA's wind-induced regulating reserve

X. CONCLUSIONS

This report examines alternative economic dispatch time steps and their impact on operating reserve deployment in the non-market areas of the WI. We adapt the reserves method from EWITS to analyze the implications of these alternative dispatch time-steps, with a focus on the impact of shorter scheduling and dispatch. The proposed EIM contains a provision for 5-minute time steps for the security constrained economic dispatch. Our analysis of alternative time steps shows that time steps that are longer than 5-minutes will require additional reserve deployment.

The proposed EIM includes two independent beneficial changes in current operating practices: sub-hourly scheduling and inter-BA netting of balancing obligations. Half of the load in the country is already served in regions with 5-minute markets: PJM, MISO, ERCOT, NYISO, ISO-NE, and CAISO. It is likely that 5-minute scheduling can be successfully implemented in the rest of the WI too. Aspects of inter-BA cooperation have been practiced for decades with contingency reserve sharing pools and energy transactions. The EIM simply extends this concept through an imbalance market using regional security-constrained economic dispatch.

Based on our analysis, we conclude that full participation of all Western Interconnection BAAs would result in maximum benefit across the Interconnection. Our analysis does not explicitly consider the impact of seams coordination at the EIM borders with the CAISO and AESO. Both of these entities operate 5-minute markets, but as currently proposed, the EIM would coordinate these seams with hourly schedules. Our analysis of the hourly scheduling practice between BPA and the CAISO suggest that faster schedule changes at the seams will have a significant impact on operating reserves. Reduced participation levels (which include examples with sub-regional footprint implementations of the EIM), and various exclusions we analyzed (BPA and WAPA) will still improve on the BAU but will fail to achieve the maximum benefit of the full participation scenario, especially for the non-participants. The participating BAs will capture 80% to 85% of the benefits of reduced reserves if BPA or WAPA are unable to participate but the non-participating BA will forgo a 60% to 70% savings. 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 should undertake a careful evaluation and analysis. It may be economically justified to implement institutional changes that help move toward a full EIM footprint. With institutional barriers mitigated, expanding EIM to all of the WI may be possible in the future and would result in additional savings.

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 coordinated unit commitment will achieve additional savings. Additional analysis would be needed to determine these impacts. Partial coordination of unit commitment may occur naturally as participants learn to anticipate what generation is likely to be available from other BAs on a bilateral basis and incorporate those options in their own unit commitment optimization. Participants may engage in bilateral contracts to add certainty to those expectations.

XI. References

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XII. Biographies

Michael Milligan received the B.A. degree from Albion College, Albion, MI, and the M.A. and Ph.D. degrees from the University of Colorado. He is part of the Transmission and Grid Integration Group at the National Renewable Energy Laboratory (NREL), where he has worked integration of wind and solar energy since 1992. He has authored or coauthored more than 130 papers, reports and book chapters and has served on numerous technical review committees for wind integration studies around the United States. Michael is a member of the Variable Generation Subcommittee of the Western Electricity Coordinating Council, member of the IEEE Wind and Solar Power Coordinating Committee, the International Energy Agency Task 25: Design and Operation of Power Systems with Large Amounts of Wind Power, and serves on the leadership team for the North American Electric Reliability Corporation (NERC) Integrating Variable Generation Task Force. Publications are available at www.nrel.gov/publications. email michael.milligan@nrel.gov

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