Flexibility Reserve Reductions from an Energy Imbalance Market with High Levels of Wind Energy in the Western Interconnection

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Technical Report
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Executive Summary

The anticipated increase in variable generation in the Western Interconnection (WI) 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 and uncertainty that must be managed by the conventional generation fleet and responsive load make 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.

Our analysis considers several alternative forms of an Energy Imbalance Market (EIM) that have been proposed in the non-market areas of the WI. The proposed EIM includes two changes in operating practices that independently reduce variability and increase access to responsive resources: BAA cooperation and sub-hourly dispatch. As proposed, the EIM does not consider any form of coordinated unit commitment; however, over time it is possible that BAAs would develop formal or informal coordination plans. This report examines the benefits of several possible EIM implementations, both separately and in concert.

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

- Balancing service: This service re-dispatches generation every 5 minutes to maintain the balance between generation and load. 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 Enhanced Curtailment Calculator (ECC) ensures correct allocation of the re-dispatch service costs.

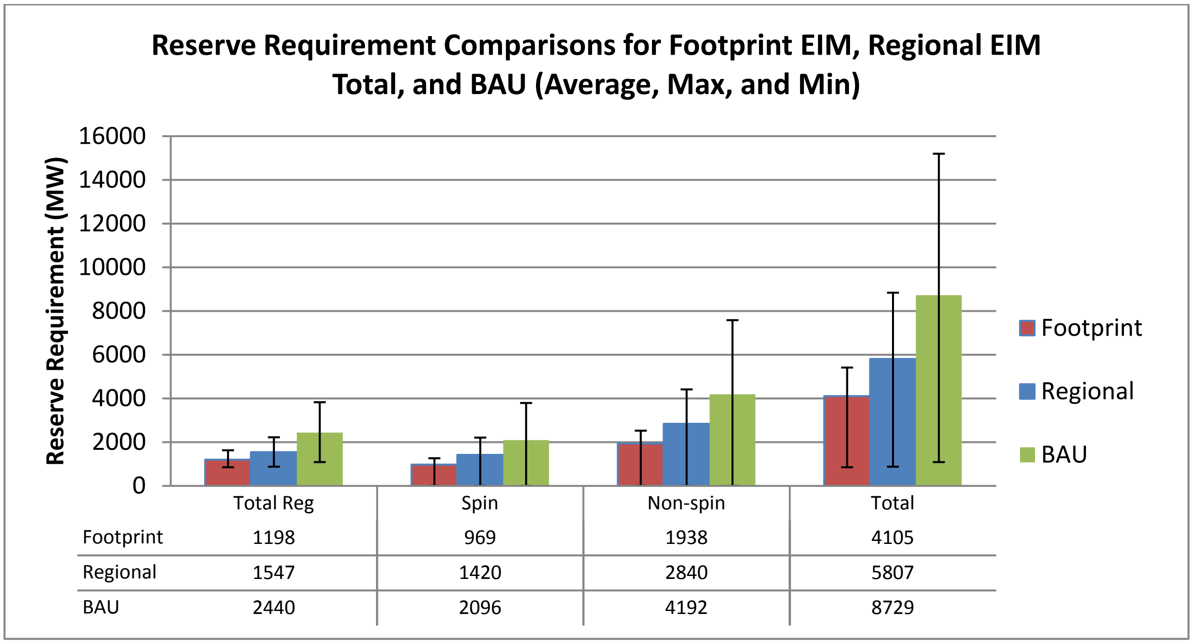
Our analysis focuses on the:

- Impact of the EIM on operating reserves, which include regulating reserves, following spin, and following non-spin
- Reduction in ramping requirements that are caused by the larger effective electrical operating footprint of the EIM
- Impact of alternative scheduling constraints on operating reserves
- Role of coordinated planning.

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.

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], focusing on the local priority case of 30% wind energy penetration (percentage of electricity production for the year). A new dataset developed by NREL and adopted for the Transmission Expansion Planning and Policy Committee (TEPPC) for the Western Electricity

Coordinating Council (WECC) was not available for this analysis; however, we are updating this work to include the current 2020 TEPPC case.[1]



	Total Reg	Spin	Non-spin	Total
Footprint	1198	969	1938	4105
Regional	1547	1420	2840	5807
BAU	2440	2096	4192	8729

Figure 1. Operating reserve requirements with alternative EIM implementations

We find that average reserve values, calculated for each hour of the study year, decrease by 51%-54%, depending on the reserve type. Reductions in maximum reserve levels range from 58%-67%, also depending on reserve type.

A lesser but significant reduction occurs with a regional implementation, with 32%-41% average reserve reduction and 42%-46% maximum reserve reductions, depending on reserve type.

[1] WECC's current cost-benefit analysis of the EIM uses the new TEPPC wind and solar base scenario, and NREL has calculated reserve requirements for WECC using the same methods described in this report.

List of Abbreviations and Acronyms

AGC: Automatic generation control

BA: Balancing Area

BAA: Balancing Area Authority

BAU: Business as Usual

BCTC: British Columbia Transmission Corporation

BPA: Bonneville Power Administration

CAISO: California Independent System Operator

CG: Columbia Grid

CPS: Control Performance Standards

DCS: Disturbance Control Standard

DOE: U.S. Department of Energy

DSM: demand-side management

ECC: Enhanced Curtailment Calculator

EDT: Efficient Dispatch Toolkit

EIM: Energy Imbalance Market

ERCOT: Electric Reliability Council of Texas

EWITS: Eastern Wind Integration and Transmission Study

FERC: Federal Energy Regulatory Commission

GW: gigawatts

ISO-NE: Independent System Operator New England

MISO: Midwest Independent Transmission System Operator

NERC: North American Electric Reliability Corporation

NREL: National Renewable Energy Laboratory

NTTG: Northern Tier Transmission Group

NWP: numerical weather prediction

NYISO: New York Independent System Operator

PJM Interconnection: Pennsylvania-New Jersey-Maryland Interconnection

RPS: renewable portfolio standards

SCED: security-constrained economic dispatch

SPP: Southwest Power Pool

WAPA: Western Area Power Administration

WI: Western Interconnection

WC: WestConnect

WECC: Western Electricity Coordinating Council

WWSIS: Western Wind and Solar Integration Study

Ancillary Service Descriptions (2010 Price Data)

The following table describes the ancillary services referenced in this report (adapted from [6]).

<table>
<tr><th rowspan="2">Service</th><th colspan="5">Service Description</th></tr>
<tr><th>Response Speed</th><th>Duration</th><th>Cycle Time</th><th>Market Cycle</th><th>Price Range (average/max) $/MW-hr</th></tr>
<tr><td colspan="6">Normal Conditions</td></tr>
<tr><td rowspan="2">Regulating Reserve</td><td colspan="5">Online resources on automatic generation control that can respond rapidly to system-operator requests for up and down movements; used to track the minute-to-minute fluctuations in system load and to correct for unintended fluctuations in generator output to comply with Control Performance Standards (CPSs) 1 and 2</td></tr>
<tr><td>~1 min</td><td>Minutes</td><td>Minutes</td><td>Hourly</td><td>33-60[#] 300-620</td></tr>
<tr><td rowspan="2">Load Following or Fast Energy Markets</td><td colspan="5">Similar to regulation but slower. Bridges between the regulation service and the hourly energy markets.</td></tr>
<tr><td>~10 min</td><td>10 min to hours</td><td>10 min to hours</td><td>Hourly</td><td>-</td></tr>
<tr><td colspan="6">Contingency Conditions</td></tr>
<tr><td rowspan="2">Spinning Reserve</td><td colspan="5">Online resources synchronized to the grid that can increase output or decrease consumption immediately in response to a major generator or transmission outage and can provide full response within 10 minutes to comply with NERC’s Disturbance Control Standard (DCS)</td></tr>
<tr><td>Seconds to <10 min</td><td>10 to 120 min</td><td>Hours to Days</td><td>Hourly</td><td>6-27 60-2000</td></tr>
<tr><td rowspan="2">Non-Spinning Reserve</td><td colspan="5">Same as spinning reserve but need not respond immediately; resources can be offline but still must be capable of fully responding within the required 10 minutes</td></tr>
<tr><td><30 min[*]</td><td>30 to 120 min</td><td>Hours to Days</td><td>Hourly</td><td>1-4 10-2000</td></tr>
<tr><td rowspan="2">Replacement or Supplemental Reserve</td><td colspan="5">Same as non-spinning reserve but with a 30- to 60-minute response time; used to restore spinning and non-spinning reserves to their pre-contingency status</td></tr>
<tr><td><30 min</td><td>2 hours</td><td>Hours to Days</td><td>Hourly</td><td>1-2 4-244</td></tr>
<tr><td colspan="6">[#] Up and down regulation prices for California and ERCOT are combined to facilitate comparison with the full-range New York prices.

[*] Non-Spinning Reserve frequently refers to a 10-minute service. Here it is assumed to be available within 30 minutes.

2008 ancillary service prices are shown because 2009 and 2010 prices appear anomalous.</td></tr>
</table>

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1 Introduction

The anticipated increase in variable generation in the Western Interconnection (WI) 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 will likely be added as well. The consequent increase in variability that must be 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 possible approaches to implementing this type of variability pooling, each of which would involve alternative levels of operational coordination beyond today's efforts. 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 implemented 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.

Our analysis considers several alternative forms of an Energy Imbalance Market (EIM) that have been proposed in the non-market areas of the WI. The proposed EIM includes two changes in operating practices that independently reduce variability and increase access to responsive resources: BAA cooperation and sub-hourly dispatch. As proposed, the EIM does not consider any form of coordinated unit commitment; however, over time it is possible that BAAs would develop formal or informal coordination plans. This report examines the benefits of several possible EIM implementations, both separately and in concert. 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.

2 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). Interestingly, there were no dramatic differences in total costs for the different scenarios. 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 (WC) footprint and 20% of all electricity in the remaining Interconnection.

The 2006 time series wind dataset was paired with the 2006 time series load data so that the common weather impacts on load and wind would be consistent. We aggregated the data into regional[2] footprints: Columbia Grid (CG), Northern Tier Transmission Group (NTTG), WC, and British Columbia. Other areas within the 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.[3]

2.1 Wind Production Data

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 dataset captures the chronological behavior of the wind that would be seen at locations around the West. The high-resolution dataset was then used to construct the various wind scenarios described above.

The NWP model of the WI 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 anomalies were seen to occur at approximately the same time, 3 p.m. every third day, starting with the first day of data for all wind plants in the dataset. Anomalous data were seen up to 3 hours before this time and 3 hours after, a side effect of the blending of model runs by the wind data contractor. These anomalous data caused 10-minute ramps more than double that seen anywhere else in the datasets. Figure 2 shows a scatter plot of 10-minute interval changes versus the interval number from a 3-day period. The red dots show where the anomalous data are found. The spikes near 90 on the x axis show the peak interval changes. The similar times (3 p.m.) on the second and third days are near 230 and 380 and do not show similar peaks.

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. The blue dots show the results of the filtering. While some artifacts of the filtering are observed, the overall shape of the envelope is similar to the same time on days 2 and 3 of the sequence.

[2] We use the term "regional" to describe aggregation of generation, load, and wind in an area such as CG. We also use the term "sub-regional."
[3] Even greater benefits could be realized if the EIM is expanded to include California and Alberta.

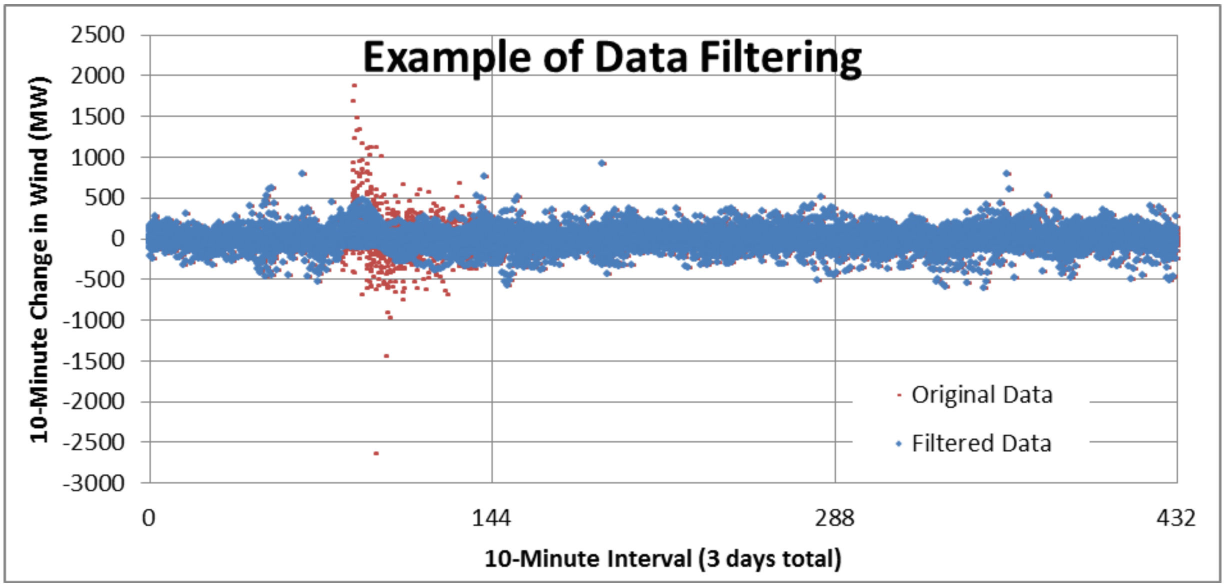


Figure 2. Example correction of the third-day anomaly in the WWSIS wind dataset

2.2 Load Data

Load time series data from 2006 were chosen from Ventyx Velocity Suite and were 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 high-resolution datasets from Bonneville Power Administration (BPA) and other Eastern Interconnection balancing authority sources. These datasets ranged from 5- to 10-minute sampling resolution for balancing authorities ranging from about 2,000 MW up to 15,000 MW. The size range was chosen to cover the range seen in the subset of Western Electricity Coordinating Council (WECC) member BAs used in the broader analysis discussed later in this report.

The load-following trend was removed from the datasets by applying a 50-minute, 0 delay moving average filter to each of the load data series. The filtered data were subtracted from the load data to leave the variability component. Figure 3 shows a graphical representation of this process.

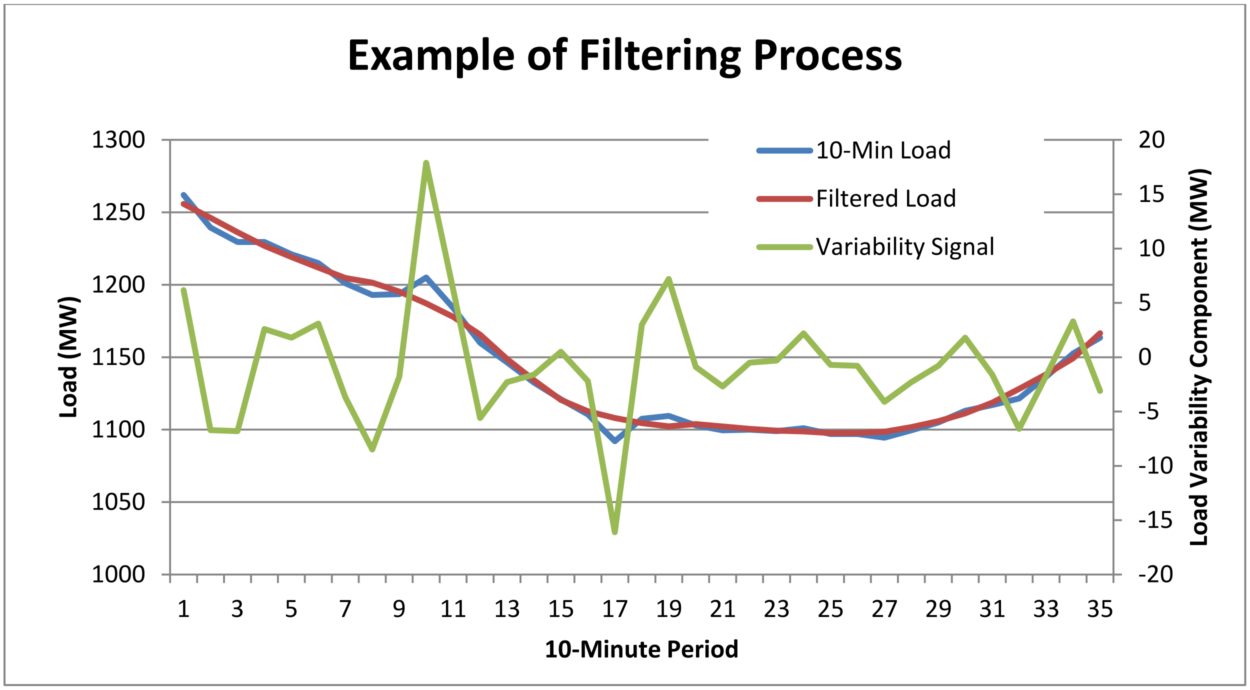


Figure 3. Graphical representation of determining load variability component

Once the variability component is isolated from the trend, the variability was characterized as a normally distributed random variable whose mean is 0. The standard deviation for each BA was calculated and plotted against the BA size.

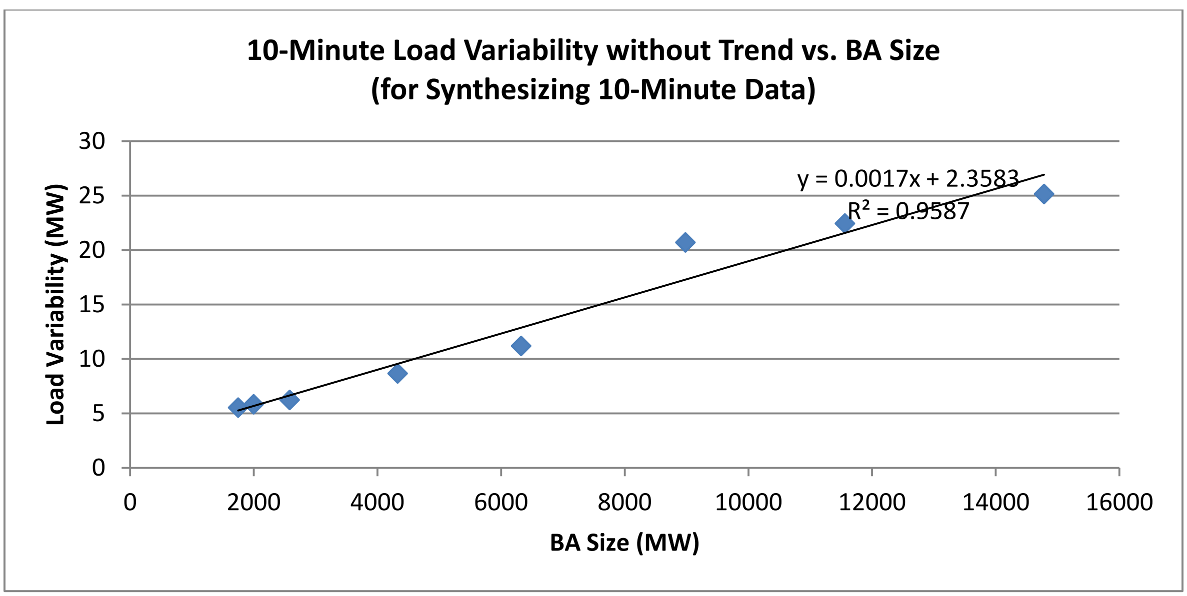


Figure 4. BA variability versus BA size for estimating 10-minute variability

The 10-minute load data are synthesized from the hourly by forming a linear interpolation at 10-minute intervals between each hourly point. Then a normally distributed random number is generated with mean of 0 and standard deviation calculated from Figure 4 and added to each of the trend points.

Figure 5 compares the results of this procedure for one of the BAs used to develop the curve in Figure 4. The 5-minute data for one of the reference BAs were averaged to generate a 1-hour dataset. The 10-minute data were synthesized as described above. The blue curve shows these results, and the red curve is the original 10-minute measured data.

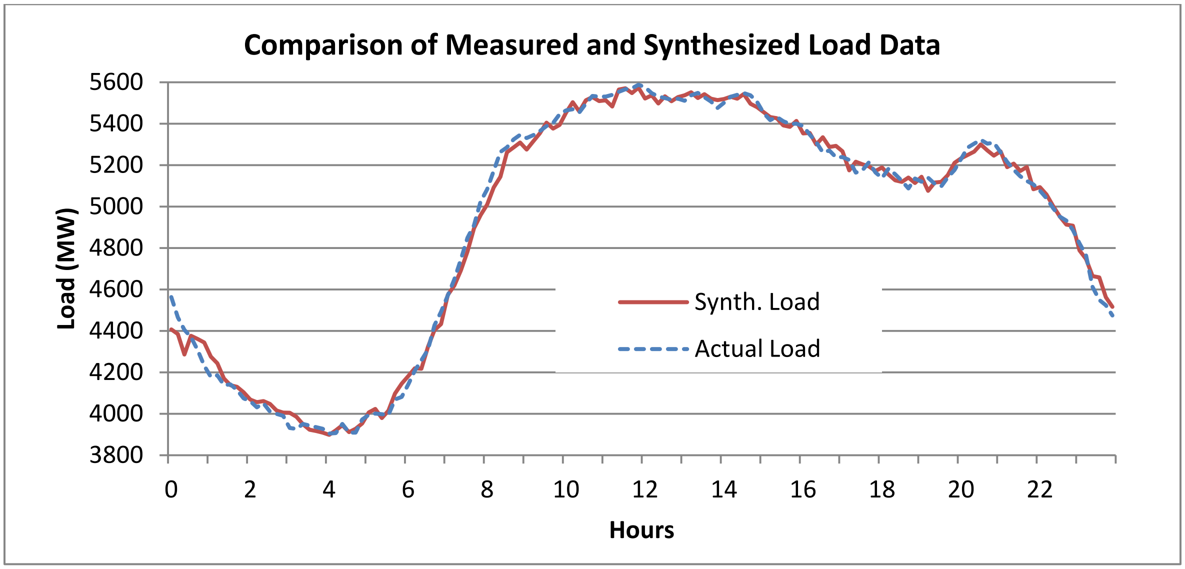


Figure 5. Comparison of actual and synthesized load data

Figure 6 shows the interval-to-interval changes for the full time range for the same BA. Note that there is a good match with the exception of the short duration peaks of less than 1 hour. The short duration peaks are lost in the averaging to 1-hour data and cannot be reconstructed through the statistics.

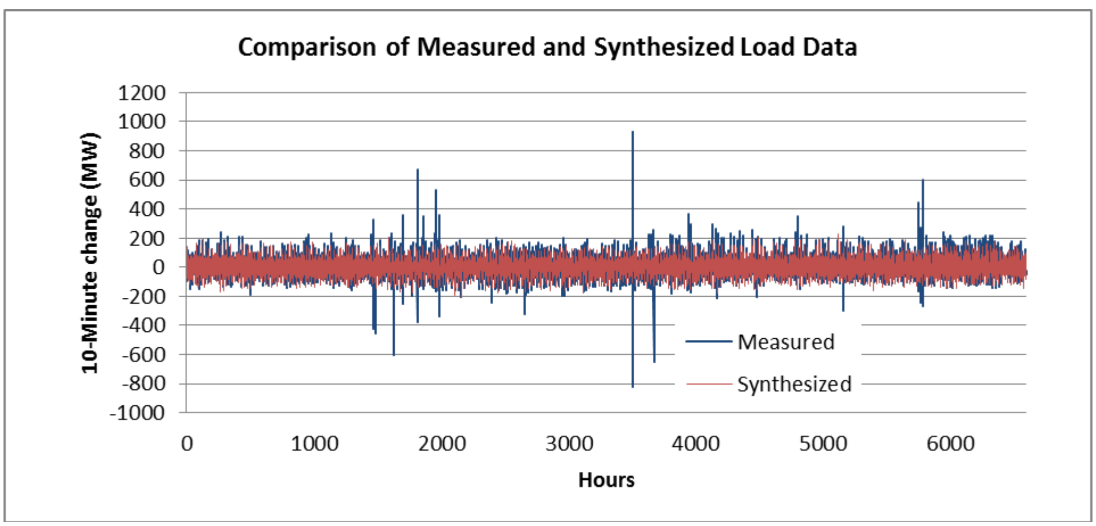


Figure 6. Comparison of interval changes for actual and synthesized data

2.3 Balancing Area Authorities and Regional Modeling

This study modeled portions of the WI not already covered by a market structure. Table 1 shows the BAAs considered as part of the study as well as regional groupings used for regional implementations of the EIM operations. Balancing authorities without load were not considered.

Table 1. BAAs and Regional Groups Considered in this Study

Columbia Grid	
Avista	PUD No 1 of Grant County
Bonneville Power Administration	Puget Sound Energy
PUD No 1 of Chelan County	Seattle City Light
PUD No 1 of Cowlitz County[4]	Tacoma Power
PUD No 1 of Douglas County	
Northern Tier Transmission Group	
Idaho Power Corp	Pacificorp West
Northwest Energy	Portland General Electric
Pacificorp East	
WestConnect	
Arizona Public Service	Sierra Pacific Power (NV Energy)
El Paso Electric	Salt River Project
Imperial Irrigation District	Tucson Electric Power
Nevada Power	Turlock Irrigation District
Public Service Company of New Mexico	WAPA - Colorado Missouri Region
Public Service Company of Colorado	WAPA - Lower Colorado Region
Sacramento Municipal Utility District	WAPA - Upper Great Plains West
Canada	
British Columbia Transmission Corporation	

Figure 7 shows a map of the reduced BA structure considered for this study. The color of the BA name indicates in which regional group it belongs: Orange indicates CG, light blue is NTTG, white is WC, and black is BCTC.

[4] PUD No 1 of Cowlitz County is not shown as an independent BAA in the WI in Figure 7. However, the original WWSIS dataset (on which this study is based) contained independent data for this entity and is included here.

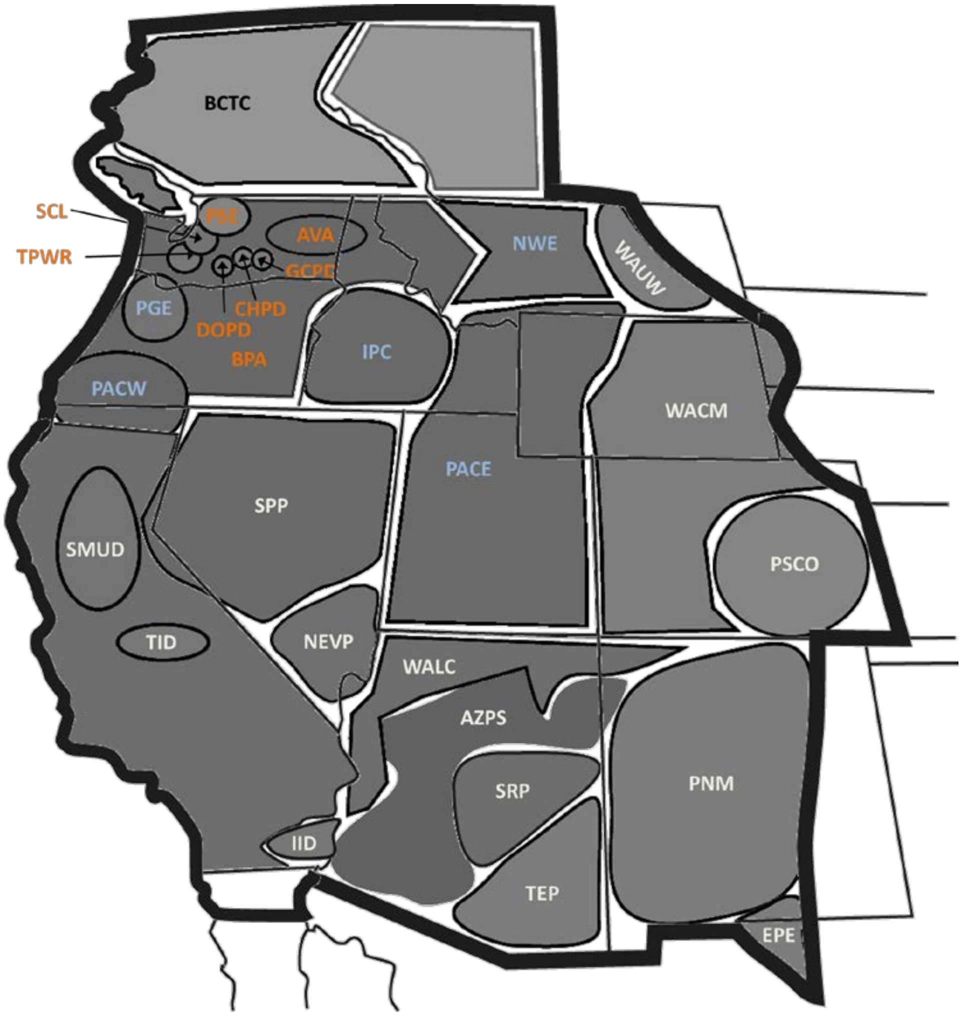


Figure 7. WECC BA map with regional groups

3 Overview of the Proposed Energy Imbalance Market and Efficient Dispatch Toolkit

In the WI, 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 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 untagged 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 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.
- 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.

Federal Energy Regulatory Commission (FERC) Pro Forma Tariff Schedules 4 (energy imbalance) and 9 (generation imbalance) provide the current approach that is used by the WECC BAAs for balancing services. The proposed EIM replaces part of the BAA 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 the WI.

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 that 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 the EDT development, the 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 WI today. Functionally, the operating steps for the proposed EIM track closely with the operating process established in the Southwest Power Pool (SPP) in its Energy Imbalance Service Market. Figure 8 illustrates the timeline for operation of the proposed EDT.

Figure 9 shows the sequence for the SPP 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 10 shows how continuously repeating the process shown in

Figure 9 results in meeting a new system dispatch point every 5 minutes, based on information that is only 10 minutes old.

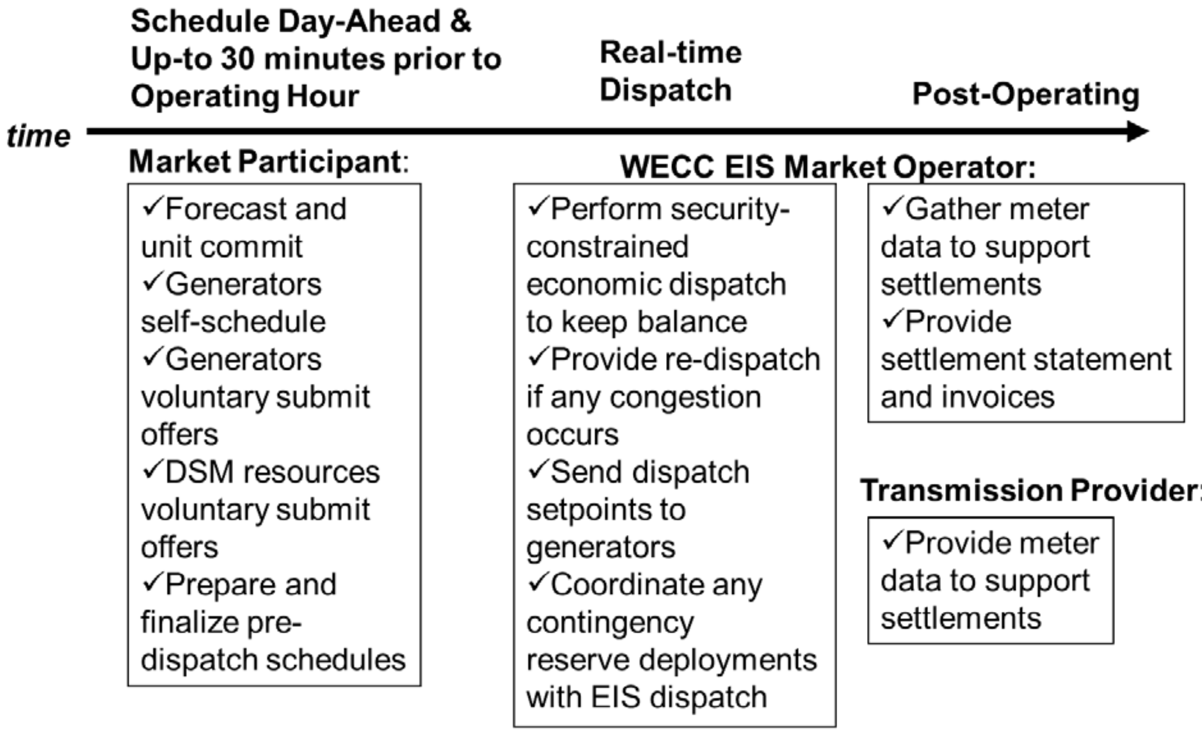


Figure 8. Operation timeline for the EIM toolkit

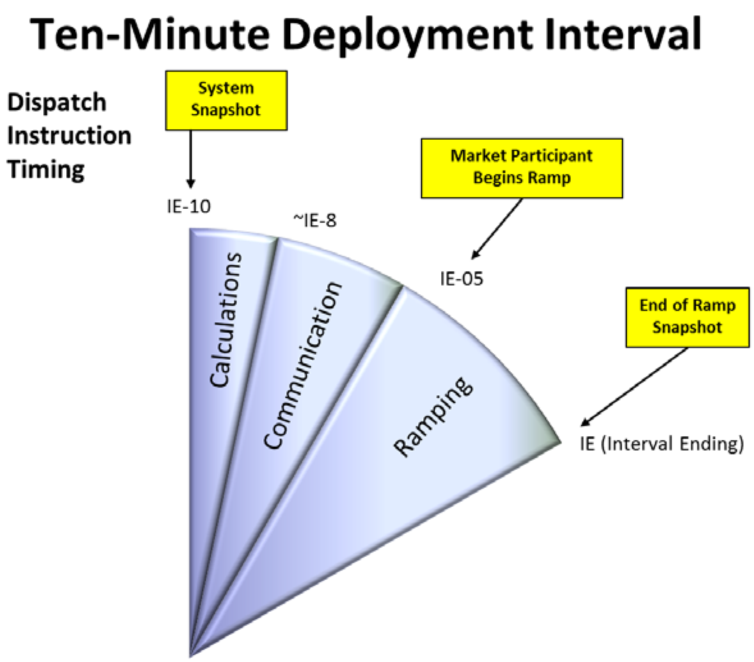


Figure 9. EIM SPP schedule for calculating setpoints and moving generation within 10 minutes

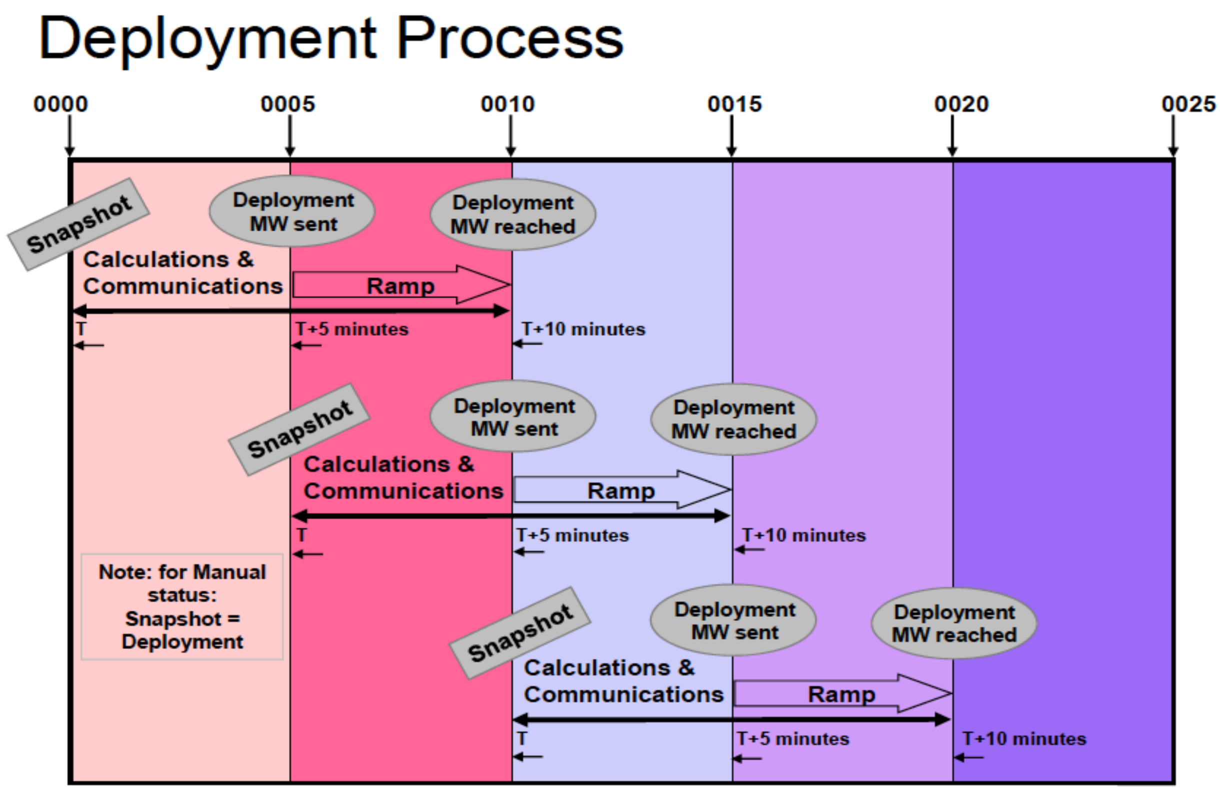


Figure 10. SPP repeats the calculations and unit ramping every 5 minutes based on system snapshots that are only 10 minutes old

The EIM would effectively implement some aspects of a virtual BA across the WI by performing a security-constrained economic dispatch (SCED) on energy imbalances (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 BA level. However, the netting of energy imbalance, which would include impacts of load and wind, is expected to be significant. Figure 11 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 net variability within the local BAs and less required ramping across the footprint.

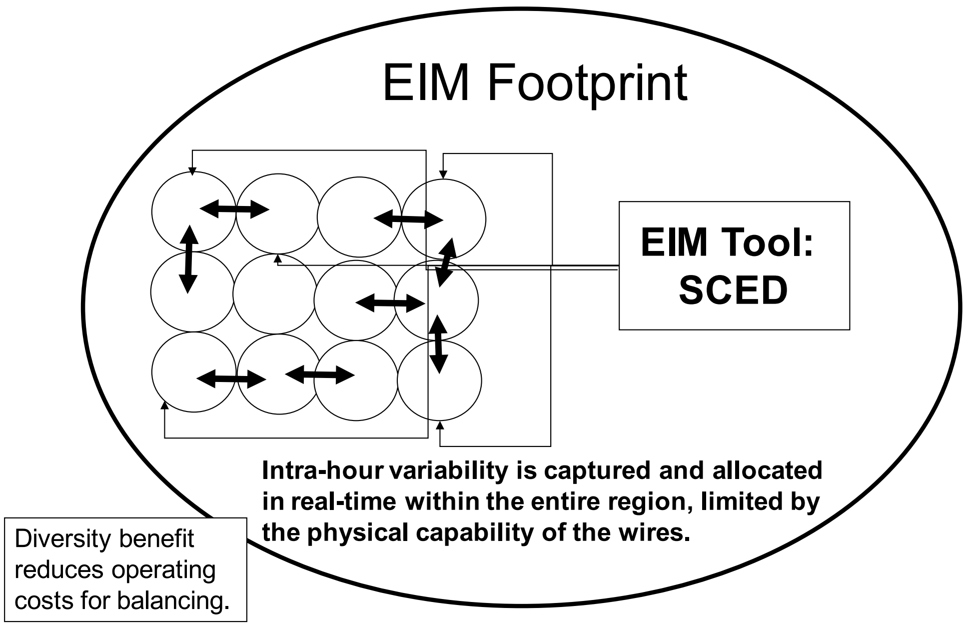


Figure 11. The EIM would effectively pool variability within the operating footprint, similar to a single BA

4 Analysis Methods

4.1 Reserve Analysis

The increased variability and uncertainty from wind and solar power causes an increase in operating reserve requirements that can be provided by some combination of flexible generation and responsive load.[5] Together these can contribute to the operating reserve that is available to help manage 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 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 dispatch updates of 10 minutes or faster. For the purposes of this work, that method was extended to cover hourly dispatch updates as well.

Short-term variability is challenging because it is difficult to fully anticipate the scheduling changes and fluctuations that must be covered with reserves. In a system with 10-minute or faster markets or dispatch updates, a common approach is to forecast a flat value for wind output for the next interval based on the past 10 to 20 minutes.[6] The wind varies on that time scale, and an understanding is needed of how it will vary during the forecast interval. Figure 12 and Figure 13 illustrate how the forecast error is calculated for both 10-minute and 1-hour dispatch schedules. The forecast error is the difference between the actual data and the forecast value.

[5] We note that wind power plants do not constitute a contingency because of the relatively slow rate at which wind power changes compared to a unit tripping offline. The operating reserve we refer to is further discussed in Ela et al. (2011).

[6] The short-term load trend can be forecast somewhat more accurately, but the load regulation movement cannot.

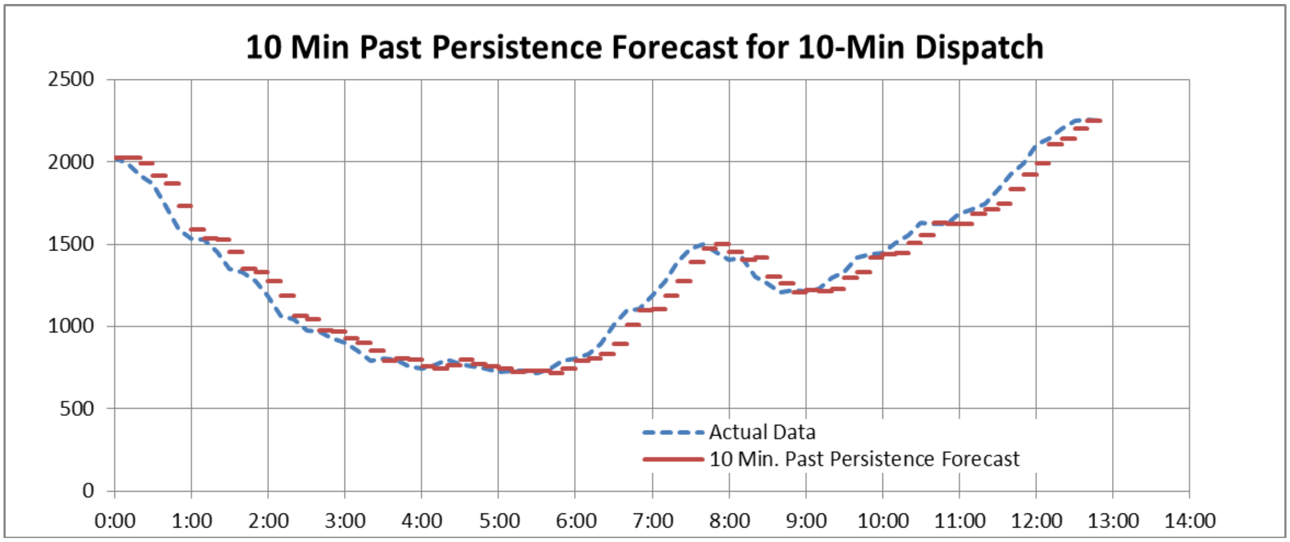


Figure 12. Forecast for 10-minute dispatch

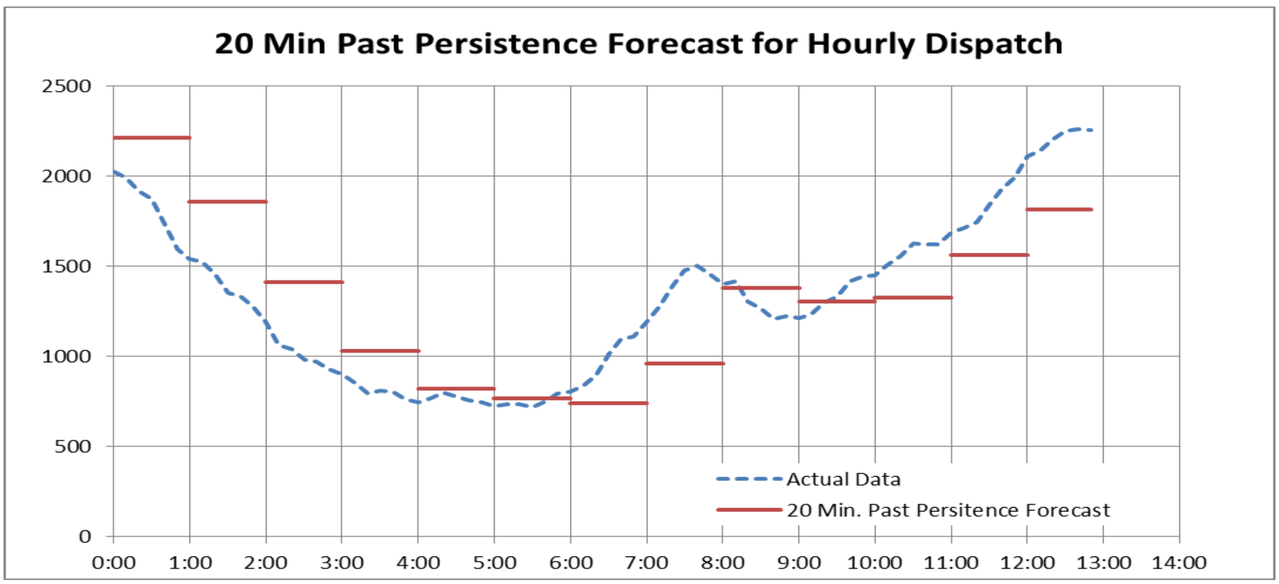


Figure 13. Forecast for 1-hour dispatch made 40 minutes prior to the beginning of the operational period

With a statistical approach that is based on detailed wind and load and forecast data, an estimate of the required 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 resource types required to fulfill them.

- 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).
- 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.

- Non-spinning and supplemental reserves are used to cover large, slower-moving, infrequent events such as unforecasted ramping events. For the purposes of this study, non-spinning reserve can be made available within 30 minutes[7] and can come from quick-start resources and responsive load. Supplemental reserves 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. Figure 14 shows an example of this function.

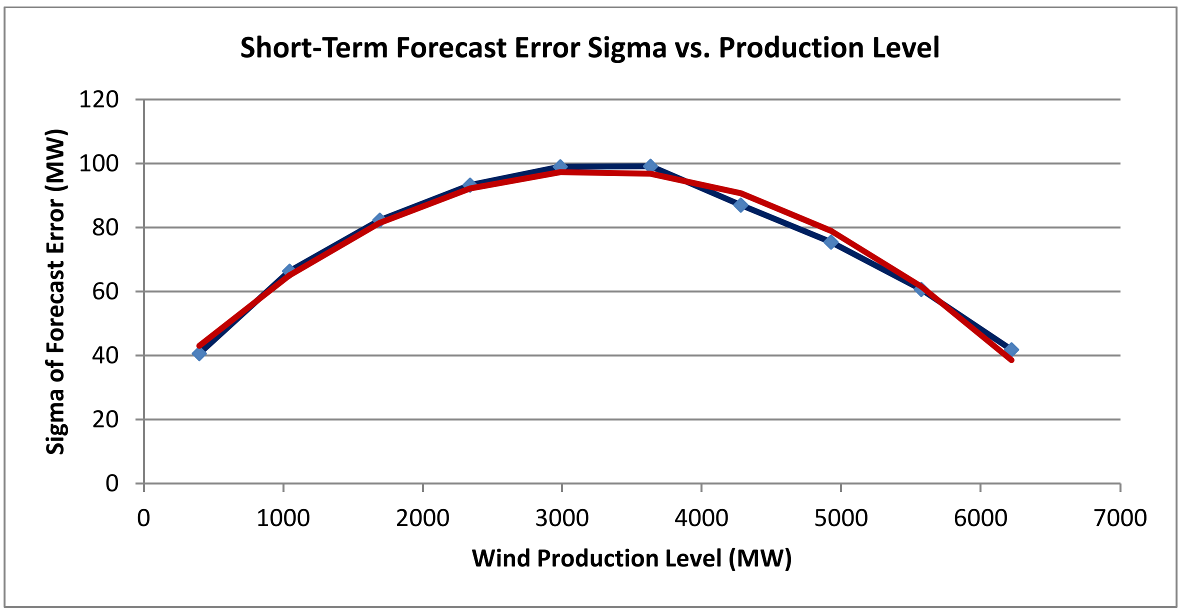


Figure 14. Short-term forecast error sigma as a function of wind production level

The curve fit polynomial curve fit shown as the smoothed line in this example is shown in Equation 1.

Equation 1. Sample calculation of hourly wind standard deviation

$$\sigma_{ST}\,(Hourly\ Wind) = -6.72E-06\ \cdot (Hourly\ Wind)^2 + 0.0437\ \cdot (Hourly\ Wind) + 26.74$$

[7] Non-spin frequently refers to a 10-minute service but is intended as a 30-minute service here.

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, as shown in Equation 2.

Equation 2. Calculation of intra-hour regulation requirement

$$Regulation\ Requirement\ (With\ Wind) = 3 \cdot \sqrt[2]{\left(\frac{1.5\%\ Hourly\ Load}{3}\right)^2 + (\sigma_{ST}\ (Hourly\ Wind))^2}$$

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 like 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. Figure 15 shows the development of the equation for hour-ahead forecast error standard deviation.

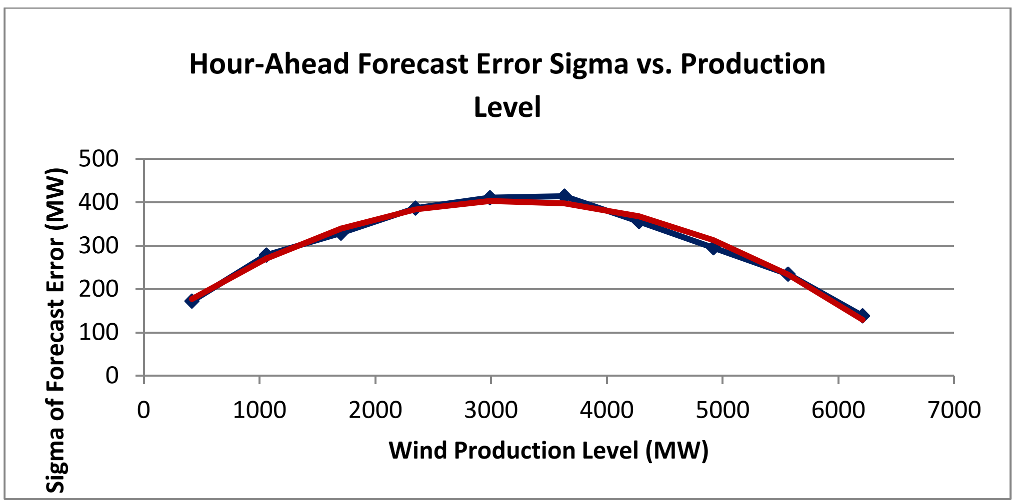


Figure 15. Hour-ahead forecast error sigma as a function of wind production level

The curve fit polynomial curve fit shown as the smoothed line, in this example, is shown in Equation 3.

Equation 3. Sample calculation of hour-head wind standard deviation

$$\sigma_{Hour-ahead}(Hourly\ Wind) = -2.985E-05\ \cdot (Hourly\ Wind)^2 + 0.1895\ \cdot (Hourly\ Wind) + 103.2$$

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 non-spin/supplemental reserves.

Equation 4 shows the function for the spinning reserves. The equation for non-spinning/supplemental reserves is the same except that 2 * sigma is used.

Equation 4. Calculation of spinning reserves requirement

$$Spinning\ Requirement\ (Hour - ahead\ wind\ forecast\ error) \\ = 1 \cdot \sigma_{hour-ahead}(Previous\ Hour\ Wind)$$

Finally, to find the total reserve requirement, each of these three components (regulation, spin, and non-spin) is added arithmetically.

Both conventional contingencies and the increased variability and uncertainty associated with wind and solar generation increase the need for responsive reserves. Because the response requirements are similar in terms of the required response speed, response frequency, and response duration, they are both expressed in terms of the same set of required reserves: regulation, spinning reserve, non-spinning reserve, and supplemental reserve. The same resources can supply the services for either need. That does not mean that dedicated contingency reserves would be used to respond to wind variability or uncertainty. It does mean that wind variability and uncertainty results in an increased need for the same *types* of reserves that are required for contingency response. Our analysis does not evaluate contingency reserves, nor do we consider whether resources that provide one type of reserve can be activated to provide another type of reserve. The issue of whether reserve types can be shared among different uses is under discussion in several forums, and we do not take a position on this issue. For the analysis in this report, we do not reduce the contingency reserve margin nor deploy contingency reserve to manage the increased variability and uncertainty of wind and solar.

4.2 Ramp Analysis

The reduction in variability and uncertainty implies that the need for ramping will be reduced under the various coordination approaches. Three approaches were used to understand the full implications of ramp reduction.

We followed a similar approach as Milligan and Kirby [2, 3] in developing ramp-reduction estimates based on the chronological wind and load data available for this study. The approach calculates hourly individual area ramp requirements, separating up-ramp and down-ramp demand for load alone and for net load (load minus wind). BAs that operate without coordination may simultaneously have ramps occurring in the opposite direction. With coordinated operations, such as would be available with the EDT, some of this ramping requirement, and therefore generator and responsive load ramping, could be reduced or eliminated. Similarly, different BAs can experience peak ramping requirements during different hours or on different days. By sharing ramping reserves, they can reduce the total reserve requirements, similar to the savings provided by contingency reserve sharing groups.

Contingency Reserves & Ramping Reserves

Contingency reserves and ramping reserves share a number of similarities but also have a few differences. The power system maintains a series of contingency reserves in sufficient quantity to ensure that it will be able to maintain the generation/load balance even if a large generator or transmission line suddenly fails. These reserves are made up of generating capacity that is held back from energy supply and/or responsive load that is available to respond.

Contingency reserves are time synchronized. Spinning reserve begins responding immediately while non-spinning reserve is fully deployable within 10 minutes and supplemental operating reserve is typically available within 30 minutes. An important characteristic of these contingency reserves is that they are used relatively infrequently (every few days as opposed to every hour) because contingency events are relatively infrequent. Consequently, the cost to stand ready to respond is more important than the response cost itself. A fast-start combustion turbine may be an economic source of non-spinning reserve even if it has a relatively high fuel cost.

Wind ramping requirements are similar to conventional contingency requirements in that large wind ramp events are relatively rare. The standby costs are often more important than the response costs, just as with conventional contingency reserves.

Wind ramps differ from conventional contingencies both in the event speed and duration. A large generator can trip and remove 1,000 MW from the power system in a cycle. Because of geographic diversity, even a fast, large wind ramp will take an hour or more to drop 1,000 MW. This means that non-spinning and supplemental operating reserves can often be used for wind ramps rather than spinning reserves. Wind ramp events are also longer than conventional contingency events. North American Electric Reliability Corporation (NERC) standards require BAs to restore their contingency reserves within 105 minutes of an event, and they typically restore their reserves much faster. [6] Slower wind ramps may require longer reserve deployments.

The important point is that wind ramps require the same *types* of responsive resources as conventional contingencies. Reserves may or may not be able to be shared between contingencies and wind ramps; the issue is still being investigated. Partial sharing may be both economic and reliable. Contingency-like reserves, however, should be used for wind ramps because they cost much less than alternatives like regulation. Table 2 presents annual average prices for regulation and the contingency reserves from five regions for 2010. Spinning reserve is only 25% to 50% of the cost of regulation while non-spinning reserve is 6% to 16%.

Table 2. Ancillary Service Prices from Five Regions Show that Contingency Reserves Are Much Less Expensive than Regulation

	California (Reg = up+dn)	ERCOT (Reg = up+dn)	New York	New England (Reg + "mileage")	MISO
		2010 Annual Average $/MW-hr			
Regulation	10.6	18.1	28.8	7.07	12.2
Spin	4.1	9.1	6.2	1.75	4.0
Non-Spin	0.6		2.3	1.15	1.5
Replacement		4.3	0.1	0.42	

Another approach involved calculating all possible ramps at 13 durations from 10 minutes to 12 hours for load, wind, and net load (load minus wind). For each duration, every possible ramp (including overlapping ramps) is calculated and tabulated. From that list, the magnitude corresponding to some percentile (90%, 99%, 99.9%, etc.) of ramps is calculated. From this data, the expectation of the magnitude and duration of ramps can be bounded by looking at the envelope formed when the negative and positive ramp results are plotted, as in Figure 16. Here we can see the relationships among the load, wind, and net load ramps at the 90th percentile. From this plot we can tell, for instance, that 90% of all 8-hour wind up-ramps will be less than 13,243 MW.

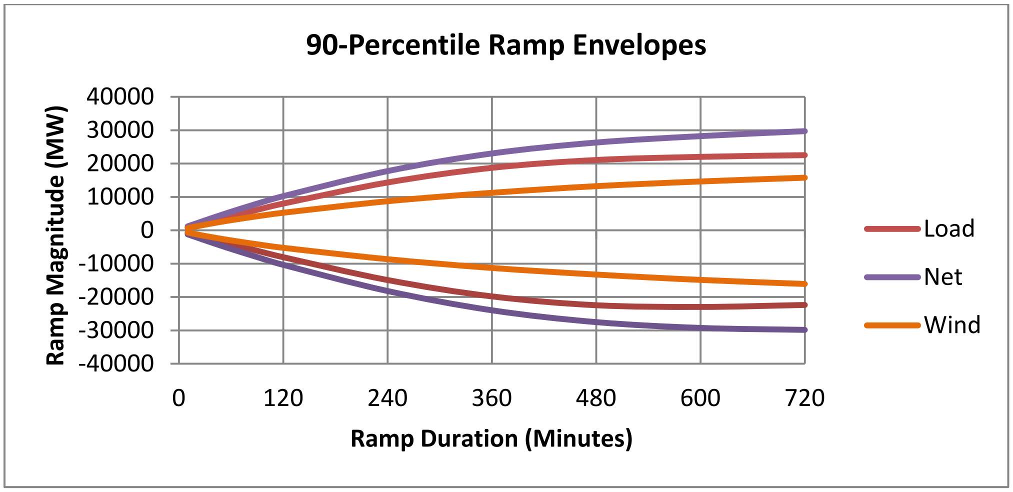


Figure 16. Sample of ramp magnitude and duration envelopes at 90th percentile

By plotting the envelopes for a series of probability levels, we can get an idea about the shape of the tails of the distributions. In Figure 17, we can see how the expected magnitude at a particular duration changes with the probability level. For instance, 90% of all up-ramps at 4 hours will be less than 13,422 MW, and 100% of those ramps will be less than 22,989 MW. The arrows on the figure indicate these examples.

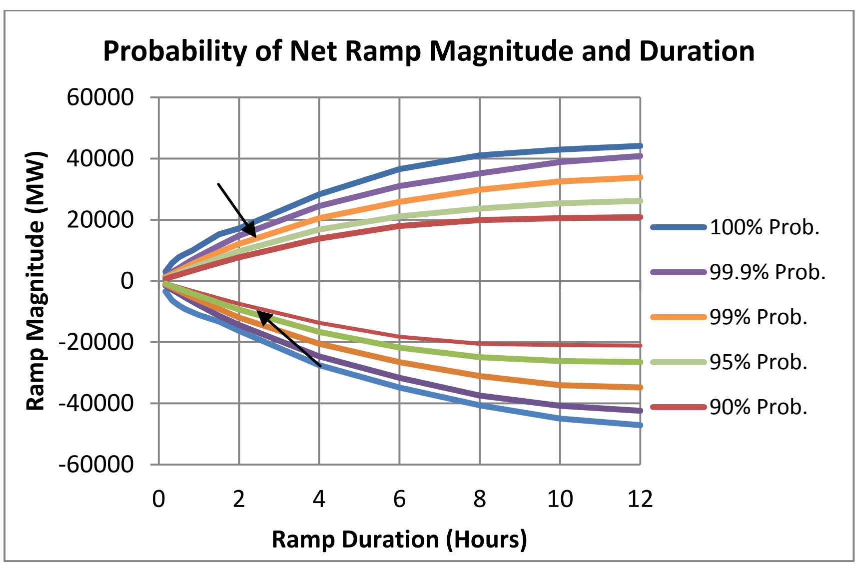


Figure 17. Sample plot of several magnitude/duration probability envelopes

Ramping requirements can be thought of in the planning horizon as well. Each BAA must have sufficient ramping capability to cope with ramps whenever they occur. To estimate the impact of separate vs. combined planning for ramping capability, we proceed in a similar fashion as above. First, we analyze each BAA separately to determine the ramping needs it will have, given the load and wind data. We again calculated ramping requirements for various time steps that ranged from 10 minutes to 12 hours. For this phase of the analysis, each ramp occurs entirely within a single calendar day, and as before, every third day is excluded from the analysis. That is, we calculate the maximum daily ramping requirement in terms of ramp size (MW) and ramp rate (MW/min) for each ramp duration (10 minutes, 30 minutes, 1 hour, 2 hours, 4 hours, 8 hours, and 12 hours). Naturally, the ramps are not independent. The maximum 1-hour ramp is likely a part of the maximum 2-hour ramp on the same day. Still, the ramp size and rate metrics for different durations provide insight into the flexibility requirements imposed on the conventional generation and demand response fleet.

Ramps are classified by size, duration, and direction. From that information, maximum, minimum, and average ramps can be calculated, retaining the classification by size, duration, and direction. "Average" in this case means the average *daily* maximum ramp of the specific duration. To obtain the total ramping needs based on separate planning, the curves are added together. Estimating the combined ramp requirements follows the same basic algorithm as the separate analysis. The only exception is that the load and wind data are combined first, and then the various ramp statistics are calculated. The procedure is carried out for load alone, wind alone, or for net load, as Figure 18 illustrates. While the previous analysis focused on real-time aggregation benefits in which an up-ramp in one BAA is countered by a simultaneous down-ramp in the opposite direction, this analysis focuses on the ramping capacity that each BAA must access. Similar to the analysis of non-coincident peak loads, if one BAA needs 100 MW of 2-hour up-ramp capability on one day and another BAA needs 200 MW of 2-hour up-ramp capability on another day, then they separately need 300 MW of 2-hour up-ramp capability because they have no way of sharing the resource. When combined, they may only require 200 MW of 2-hour up-ramp capability if the ramps in fact happen on different days because they can now share the resource.

The four traces on the graph appear for both positive and negative ramp requirements. The upper quadrant of the graph shows the aggregated maximum and un-aggregated maximum ramps (top two traces), which represent the separate (un-aggregated) and combined (aggregated) ramping needs. The difference between the curves shows the maximum ramping capability that could be avoided by coordinated planning and subsequent operations.

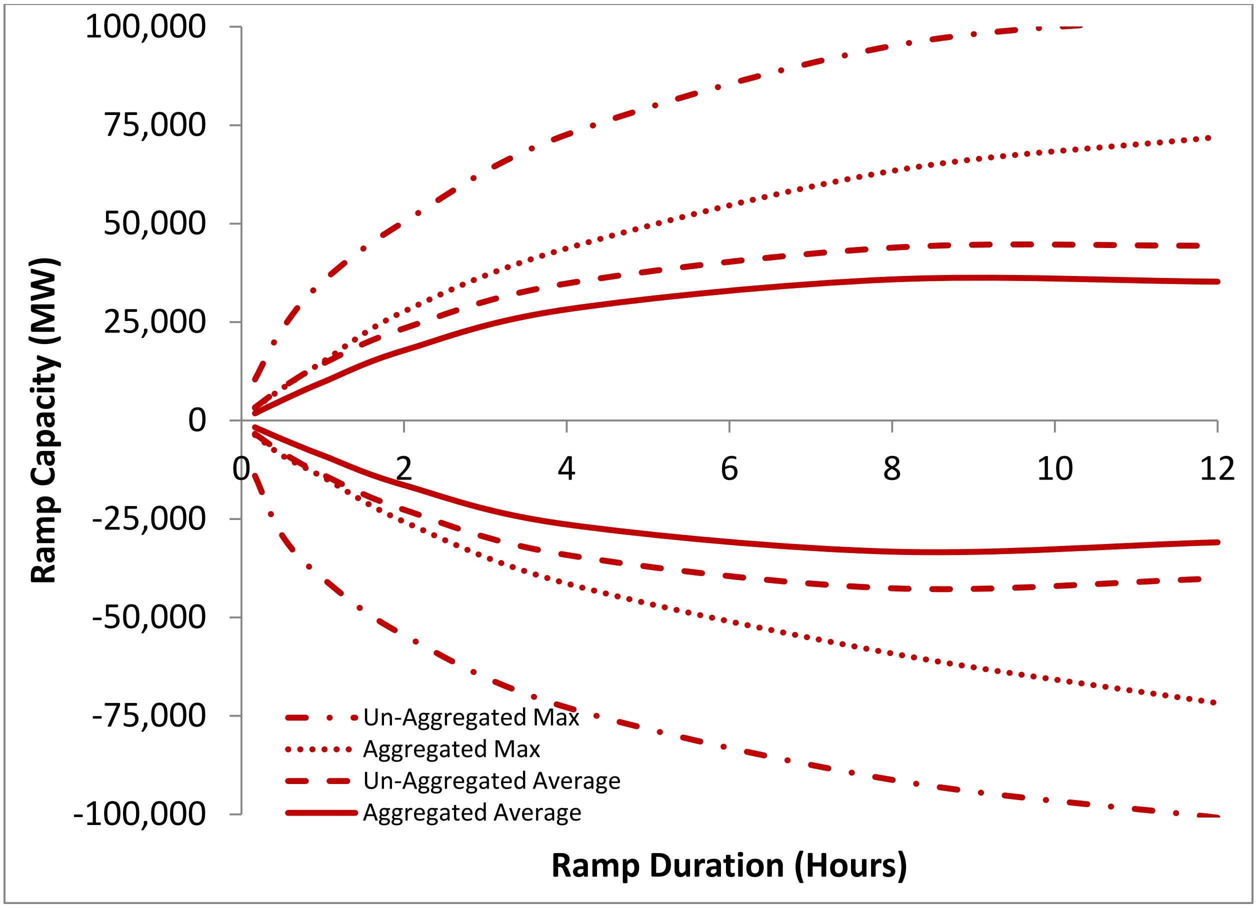


Figure 18. Example ramp duration curves for net load show the benefit of combined planning for ramping adequacy

5 Impact of Energy Imbalance Markets on Reserves and Ramping

Per-unit wind variability is reduced with increased geographic diversity, reducing the level of reserves needed to compensate for that variability. Forecast errors are also reduced by diversity [5].

5.1 Alternative Market Scenarios

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

Table 3 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.[8] 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 WI except for Alberta and California.

The proposed EIM would operate at the 5-minute level, aggregating energy settlements to hourly (similar to the 5-minute markets currently operated by Pennsylvania-New Jersey-Maryland Interconnection [PJM], Midwest Independent Transmission System Operator [MISO], New York Independent System Operator [NYISO], Independent System Operator-New England [ISO-NE], Electric Reliability Council of Texas [ERCOT], and California Independent System Operator [CAISO]); however, our analysis evaluated alternative dispatch intervals of 10 minutes, 30 minutes, and 60 minutes because of data limitations. As discussed in [5], 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 4 illustrates the scheduling and dispatch intervals and forecast assumptions for wind.

Table 3. Scenario Descriptions

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

Table 4. 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

[8] It is also possible that a version of EIM may eventually be extended to include all of the WECC.

The 10-minute schedule with the 10-minute dispatch interval is the basis for the analysis in this report and is implied in all scenarios unless otherwise noted.

5.2 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.

Although the aggregation 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 wind data were not available. The full footprint includes all of the WI except for Alberta and California.

Table 5. Summary of Load and Wind Data Variability

	Footprint	West Conn.	North. Tier	Colum. Grid
# of BAs	28	14	5	9
Load MW				
Max Non-Coincident	109,587	62,512	23,971	23,104
Max Coin.	102,399	60,820	23,116	22,681
Average	64,095	33,512	15,820	14,587
Min Coincident	44,652	22,511	10,623	10,201
Min Non-Coincident	40,218	21,286	10,200	8,731
Wind MW				
Max Non-Coincident	48,933	26,167	10,914	11,853
Max Coin.	40,392	24,398	10,430	11,702
Average	16,413	8,604	3,802	4,006
Min Coincident	239	124	69	2
Min Non-Coincident	4	1	3	1
Non-Coincident CF	34%	33%	35%	34%
Coincident CF	41%	35%	36%	34%
Wind Penetration				
Max in Area	835%	835%	180%	227%
Max Coincident	77%	95%	80%	108%
Energy	26%	26%	24%	27%

Wind penetration refers to the ratio of annual wind energy to total generation.

Figure 19 shows the peak load and wind coincidence for all of the WI and the three 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 7% lower for the overall footprint 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: 9.9% for WI and 14.4% for Columbia Grid. Load factor is 6% better for the aggregated footprint (65% versus 59%).

Aggregation also benefits wind. Peak WI wind is reduced by 15.3% through aggregation. WI aggregated minimum wind is 420 MW, compared with zero to 43 MW for the individual sub-regions. Footprint wind capacity factor increases by 7% with aggregation. Aggregating wind also reduces the maximum wind penetration. One BA in WestConnect (WAUW) has a maximum 10-minute wind penetration of 835%, which is reduced to a maximum of 95% for the aggregated WestConnect and a maximum 66% for the aggregated footprint.

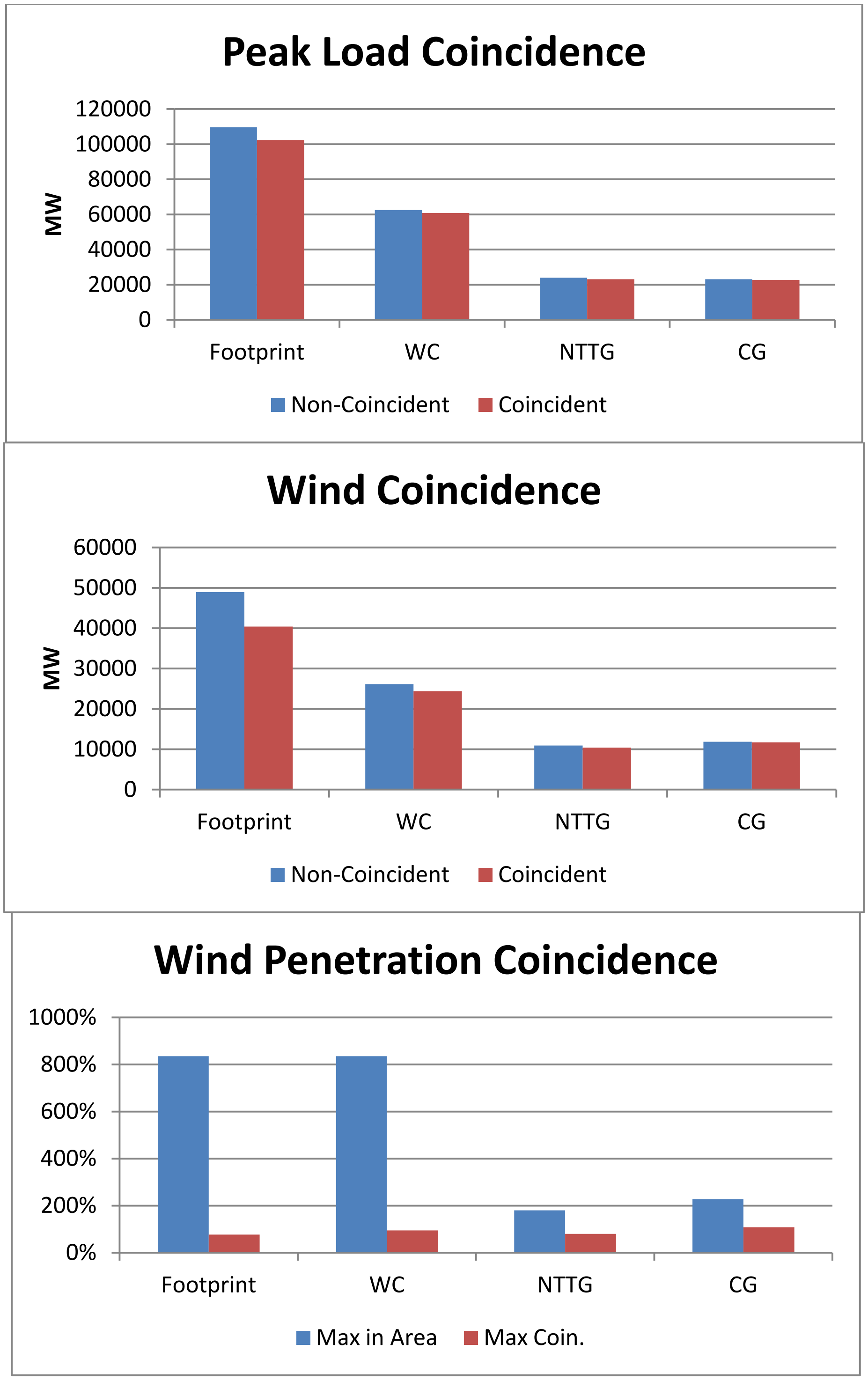


Figure 19. Coincidence of wind, load, and hourly penetration

5.3 Footprint EIM Scenario – Base Case

The base scenario for our analysis compares the footprint-wide EIM with each balancing authority managing the variability wind and load located in their borders, the Business as Usual (BAU) case. The footprint-wide EIM includes all of the BAs included in the study cooperating to manage that variability.

5.3.1 Reserves

As described in the Analysis Methods section above, three categories of reserve requirements were calculated for the footprint EIM and BAU scenarios. Figure 20 shows the comparison of the regulation, spin, and non-spin/supplemental reserves. The whiskers show minimum and maximum values and the bar shows the average value for all hours of the year.

For each category of reserves, the requirement is cut approximately in half. Total regulation is cut from 2,440 MW for the BAU case to 1,198 in the footprint EIM.

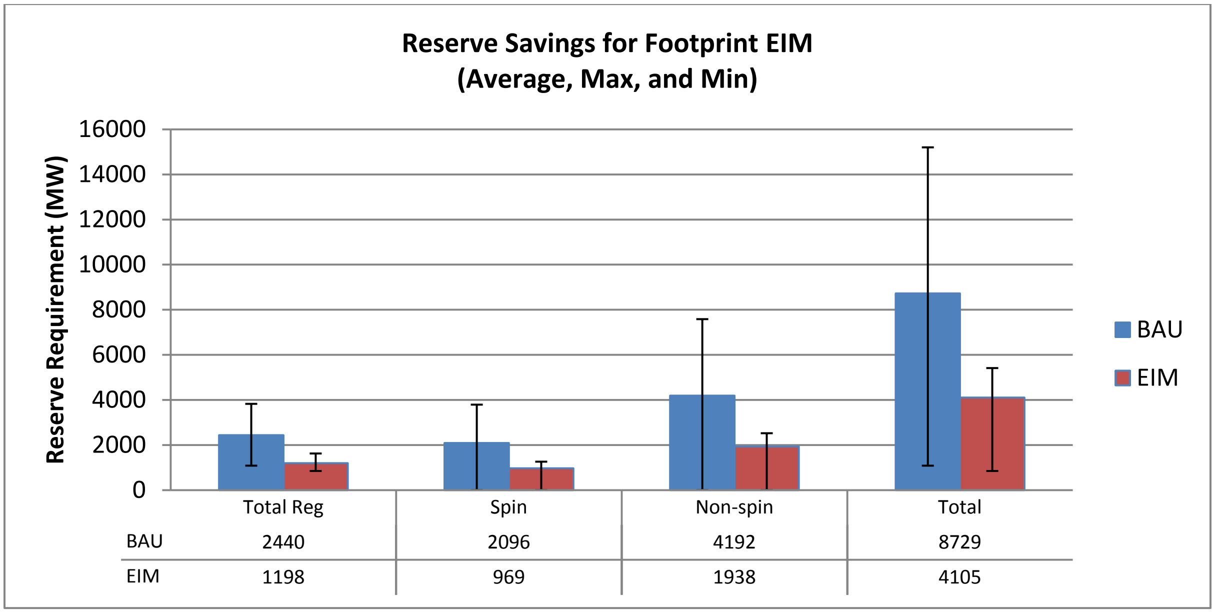


Figure 20. Comparison of reserve requirements for the footprint EIM to BAU

Table 6. Reduction in Reserves Maximum Values

	Regulation	Spin	Non-Spin	Total
BAU	3,826	3,791	7,582	15,200
EIM	1,626	1,262	2,524	5,412
Reduction in Max Value	58%	67%	67%	64%

To understand how often various amounts of reserves are required, we developed regulation and total reserves duration plot. Total reserves are the sum of the total regulation, spin, and non-spin requirements. Figure 21 shows total reserves duration for the BAU and footprint-wide EIM case. The black line shows the saving in total reserves that are realized when the footprint EIM is implemented. The plot shows the large decrease in the overall requirements but particularly for the large, infrequent tails events.

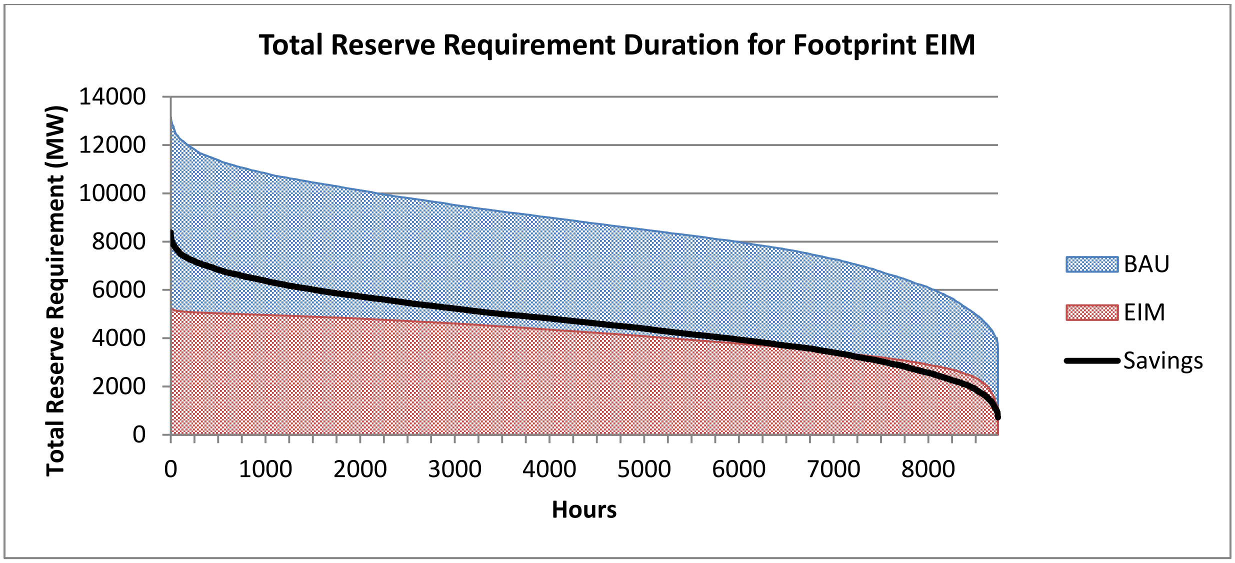


Figure 21. Comparison of footprint-wide EIM to BAU total reserve requirement

Interestingly, the total reserve requirement for the large aggregation is flatter as well as lower than when reserves are supplied for each BA individually. The same pattern is seen for regulation for the scenario regions, as shown in Figure 22.

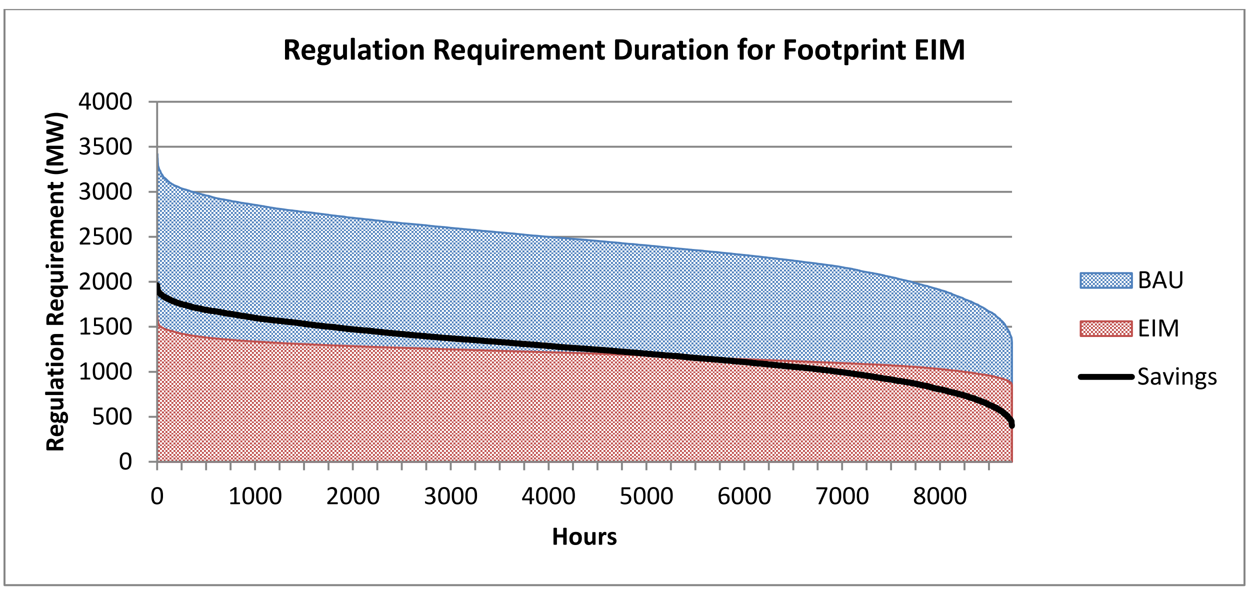


Figure 22. Reduction in total regulation reserve requirements by implementing a footprint-wide EIM

5.3.2 Ramp Demand Reduction

The reduction in variability implies that the need for ramping will be reduced under the various coordination approaches. We followed a similar approach as Milligan and Kirby [2, 3] in developing ramp-reduction estimates based on the chronological wind and load data available for this study. The approach calculates hourly individual area ramp requirements, separating up-ramp and down-ramp demand for load alone and for net load (load minus wind). BAs that operate without coordination may simultaneously have ramps occurring in the opposite direction. With coordinated operations, such as would be available with the EDT, some of this ramping requirement, and therefore generator ramping, could be reduced or eliminated.

Figure 23 illustrates the concept for a sample 1-week period. This graph assumes that the EDT would operate across the entire footprint. As shown in the graph, there is a benefit even without any wind because of the load diversity. However, as also can be seen in the graph, there is a much larger ramp saving at a high wind penetration rate, largely because a high wind penetration will cause a significant increase in ramping demand for many hours of the year and the greater amount of geographic diversity in wind ramps as compared with load ramps.

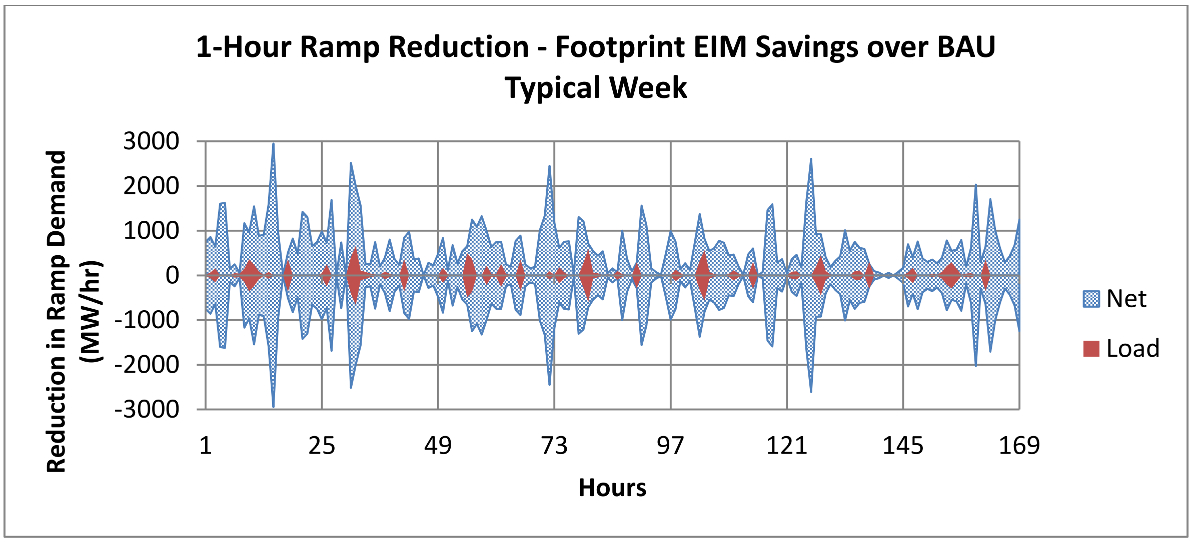


Figure 23. Footprint-wide ramping that can be eliminated by the EDT for a sample 1-week period

Figure 24 shows a duration plot for the load and net ramp savings for the entire 8,760 annual hours. For 134 hours per year the savings in net ramp exceeds 2,000 MW and averages about 550 MW for the year. Load ramp savings over the year average about 90 MW. Again, the effect of aggregation on wind ramp savings is clearly higher than for load alone.

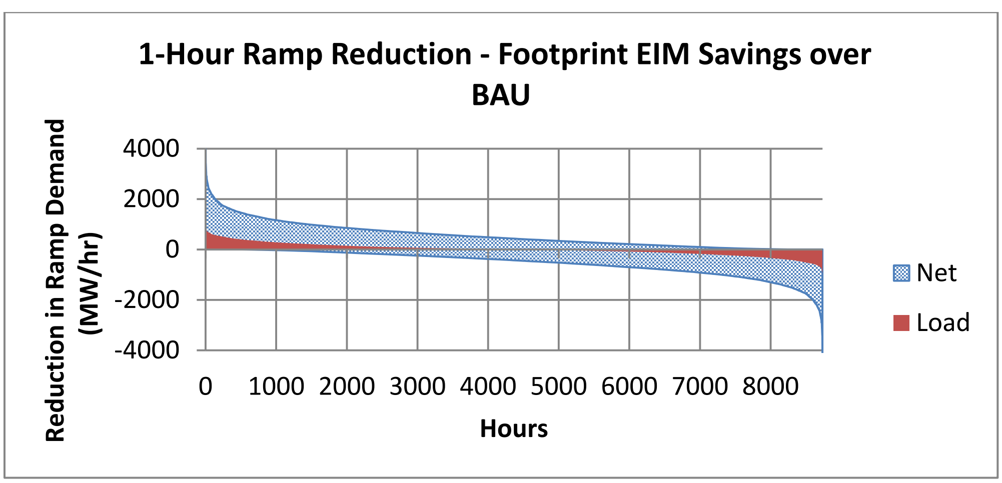


Figure 24. Frequency and magnitude of annual ramping reductions

Also of interest is the timing of the ramps and ramp savings.
Figure 25 and Figure 26 show by week of the year (1 to 52 on the vertical axis) and hour of the day (on the horizontal axis) when the ramp and ramp savings occur. Note that the hours are relative to Mountain Standard Time and there is a 1-hour delay in the savings plot because savings is referenced to the beginning of the hour. An interesting observation is that the maximum ramp savings do not always line up with the peak daily up-ramping, as seen in Figure 25. In the summer, the peak savings seem to occur at or just after the peak load periods where the slope of the afternoon ramp has started to decline. In the winter months, the peak savings is nearly coincident with the peak morning ramp. The savings don't align with the peak ramp because load dominates the morning ramps and there is little diversity in the load ramps. The best load diversity across the footprint occurs just before and just after the major daily load ramps because of the two time zones involved. Also, wind ramp savings tend to be at a minimum on summer mornings and maximum in the late afternoon.

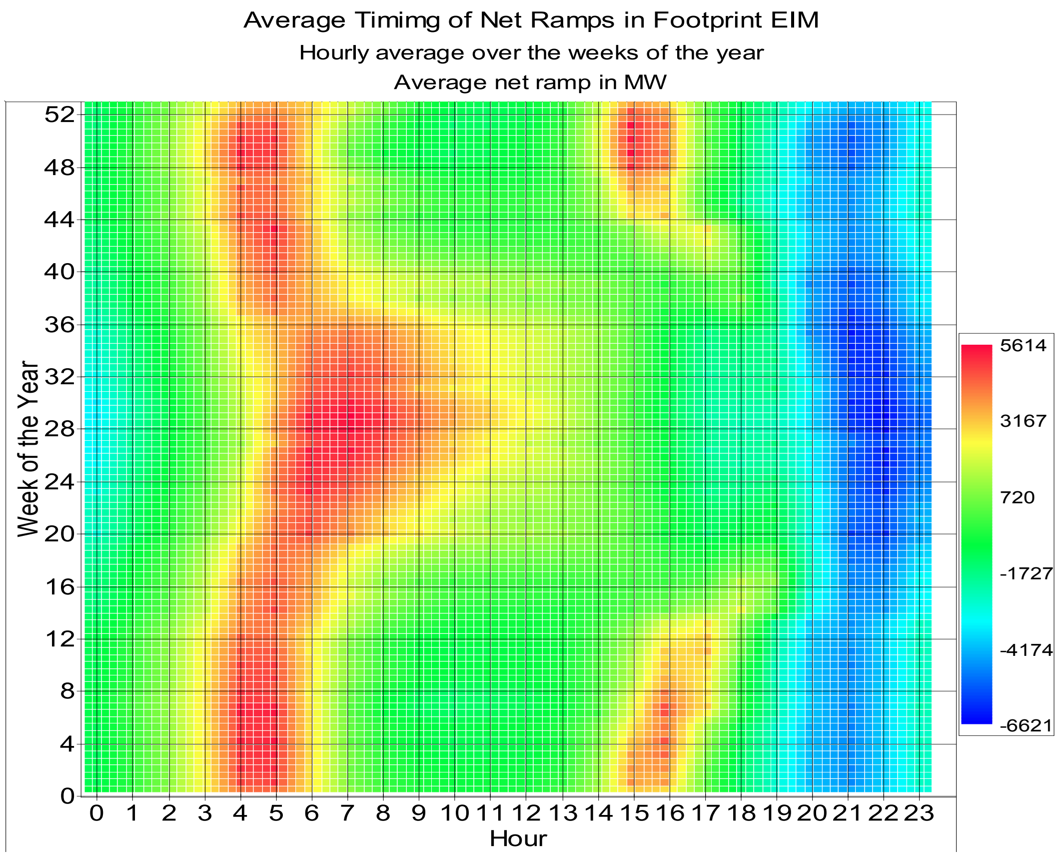


Figure 25. Average timing of ramp events during the year

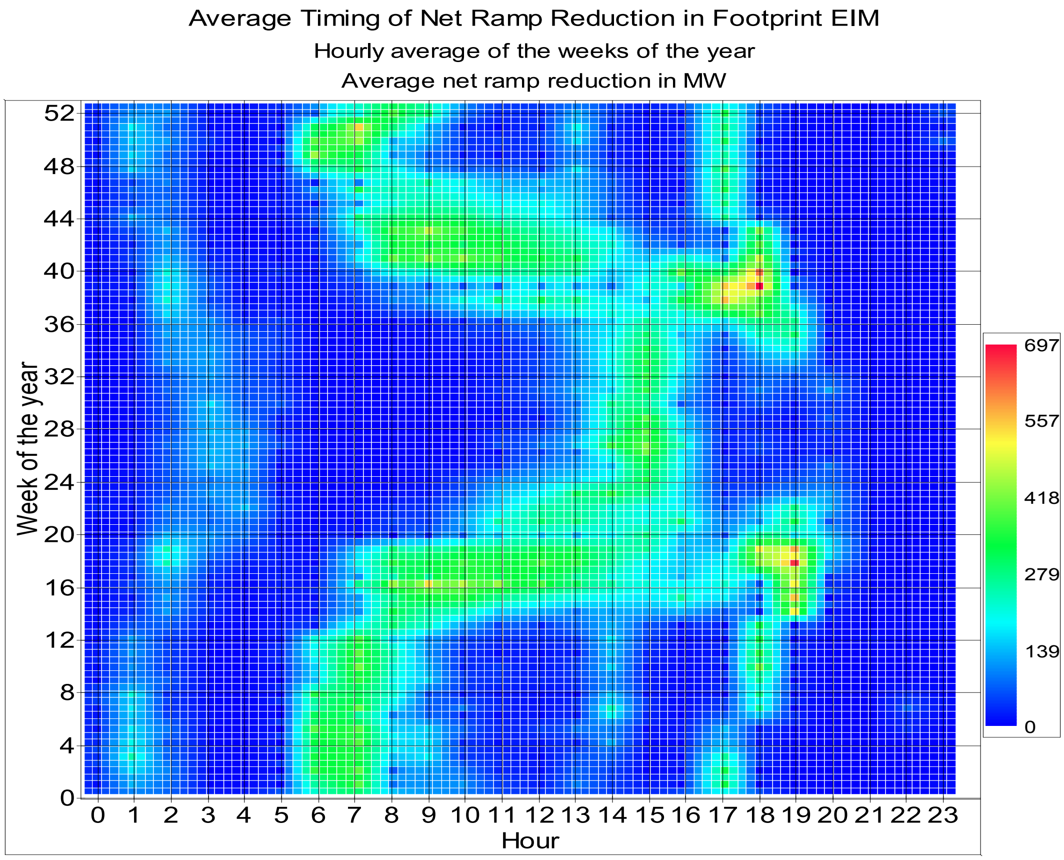


Figure 26. Average timing of ramp saving over the year

5.3.3 Ramp Magnitude and Duration Probability

Ramping requirements are also reduced with aggregation. Figure 27 through Figure 29 show the ramping requirements of load, wind, and net load for the non-coincident case in which all 29 BAs meet their own requirements (Figure 27) and the coincident case in which all 29 BAs cooperate to meet the total system ramping requirement (Figure 28). The figures show the 95th percentile to provide a conservative comparison Control Performance Standard (CPS) 2 requirement. 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 55% and net-load-ramping requirements by about 35%. Load does not get as much ramping benefit from aggregation because the daily load pattern is highly correlated across the region. Figure 29 shows the reduction in ramp magnitude at the 95th percentile.

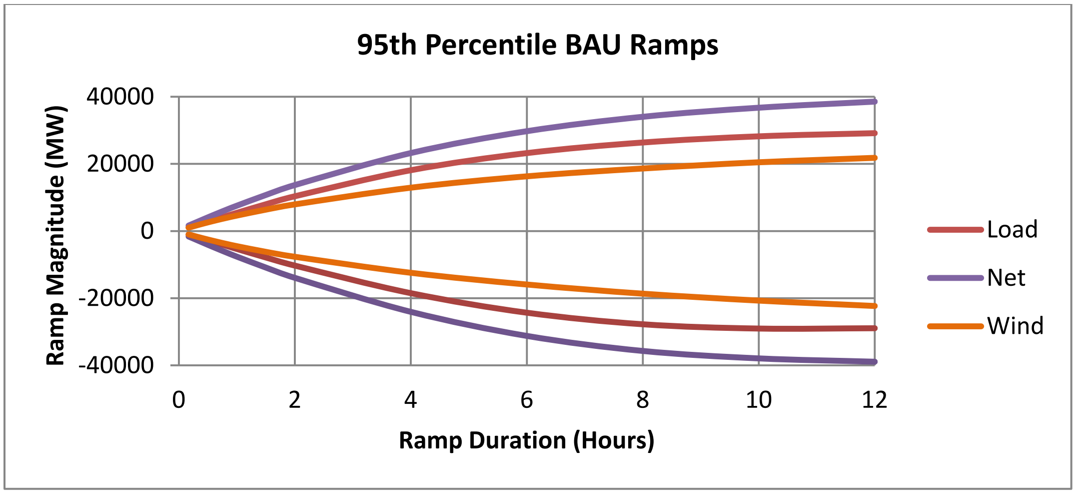


Figure 27. BAU ramp magnitude and duration plot, 95th percentile

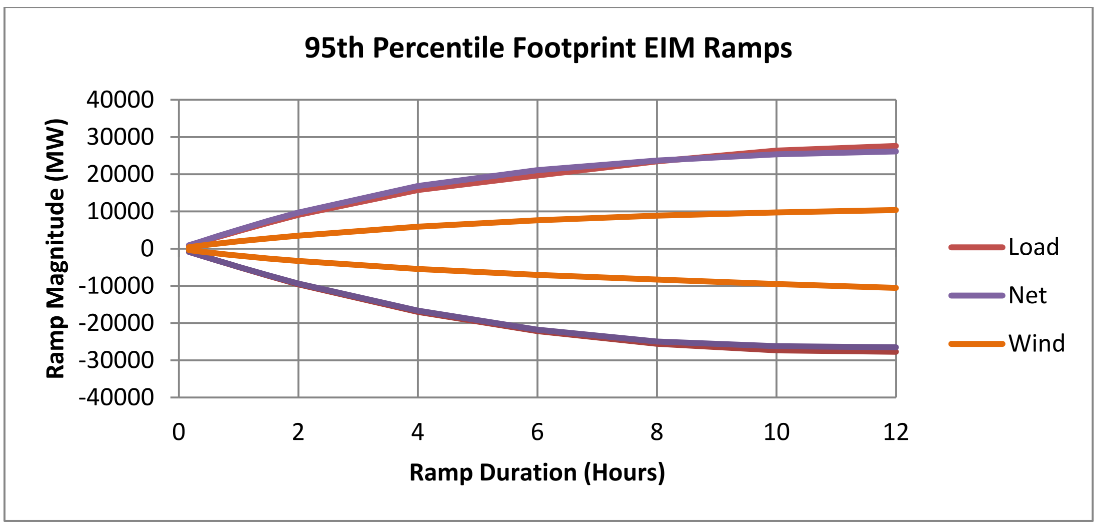


Figure 28. Footprint EIM ramp magnitude and duration plot, 95th percentile

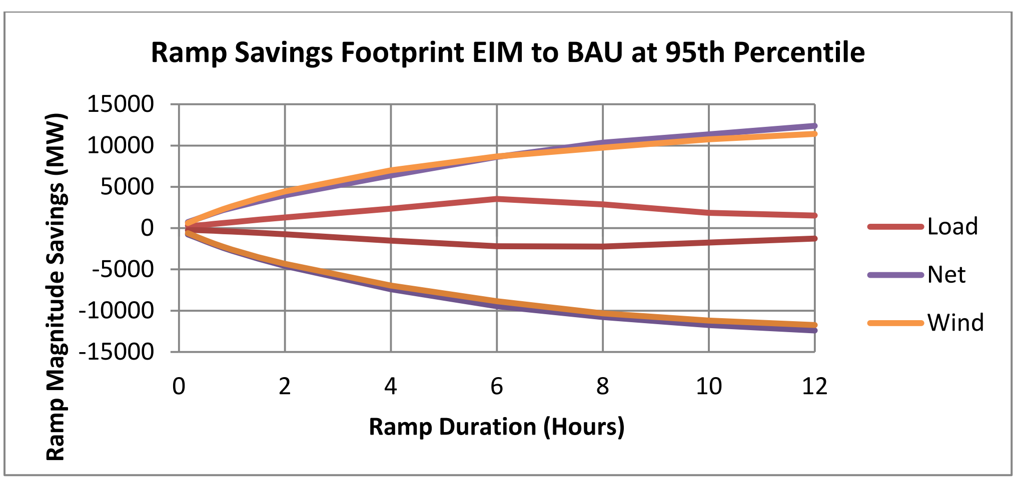


Figure 29. Reduction in ramp magnitudes for the footprint EIM

Extreme ramp events are relatively rare, as can be seen in Figure 30. At 12 hours, the worst net ramp events are greater than 44,000 MW, but 99% of all ramps at the same duration are less than 34,000; 90% of all 12-hour ramps are less than about 20,000 MW.

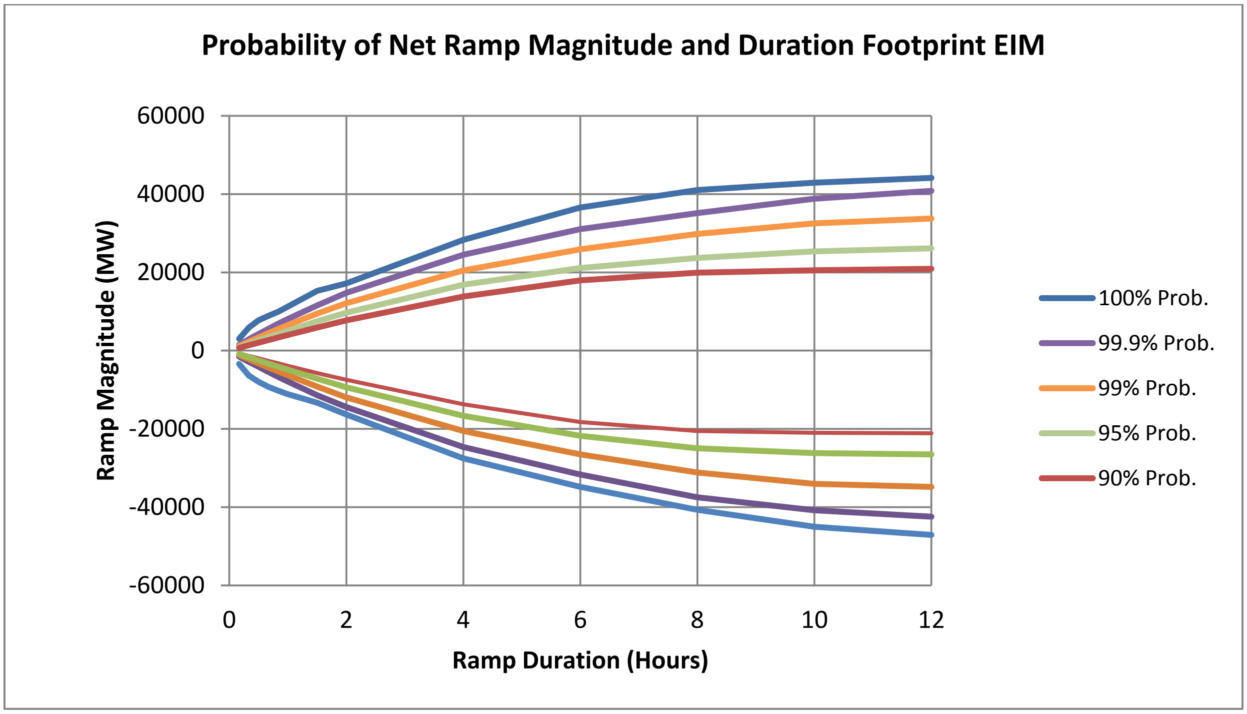


Figure 30. Magnitude and duration probability graph for the footprint EIM case

5.3.4 Implication for Planning

System planners must ensure that there is sufficient ramping capability to follow the net load, just as they must ensure that there is sufficient generation to meet the peak net load. Table 5 showed the significant capacity benefits that can be realized through BA cooperation or aggregation in operations. There is a similar benefit that accrues when planning is coordinated over a broader region. With un-coordinated planning, each BAA (or entities within the BAA) must plan for sufficient generation to cover expected peak conditions and also to provide sufficient flexibility: ramping, minimum turn-down, and short minimum up- and down-times. With coordinated planning, aggregation reduces needed ramping requirements. Figure 31 shows both the maximum ramping capacity required for each ramp duration for the year as well as the average of the daily peak ramping requirements. The un-aggregated curves represent the ramping requirements that would be necessary with uncoordinated planning, whereas the aggregated curves show the needed ramping requirements with coordinated planning. Interestingly, aggregation reduces the maximum annual ramping requirement significantly more than it reduces the average daily ramping requirement. This is because the daily load shape is highly correlated between the BAs in the aggregation.

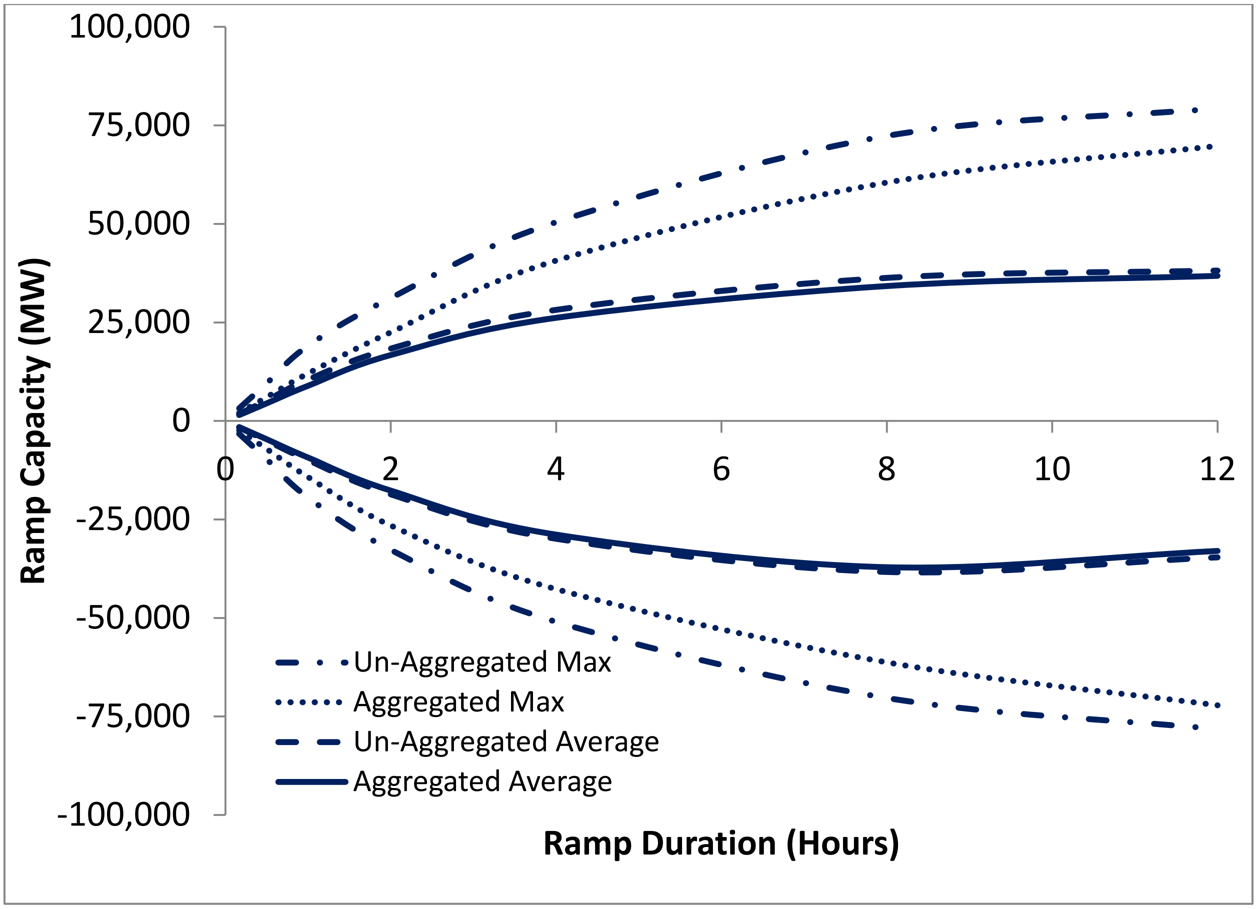


Figure 31. Footprint daily maximum load ramping requirements for 1 year

Figure 32 shows the wind ramping requirements for the EDT footprint while Figure 33 shows the net load ramping requirements. For convenience, the ramping sign convention for loads is used in all of the figures. A positive ramp represents a load increase or a wind decrease since both require conventional generation to ramp up in response. Several characteristics are apparent in the ramping data. One is that the wind ramping requirements are significantly lower than the load ramping requirements. Second is that there is a greater ramping aggregation benefit for wind than for load indicating greater diversity in wind patterns than in load patterns. Third, the maximum annual ramping requirements are significantly greater for both load and wind than the average daily maximum ramping requirements. Especially in the case of wind, large ramps are rare. Finally, aggregation benefits remain strong for net load.

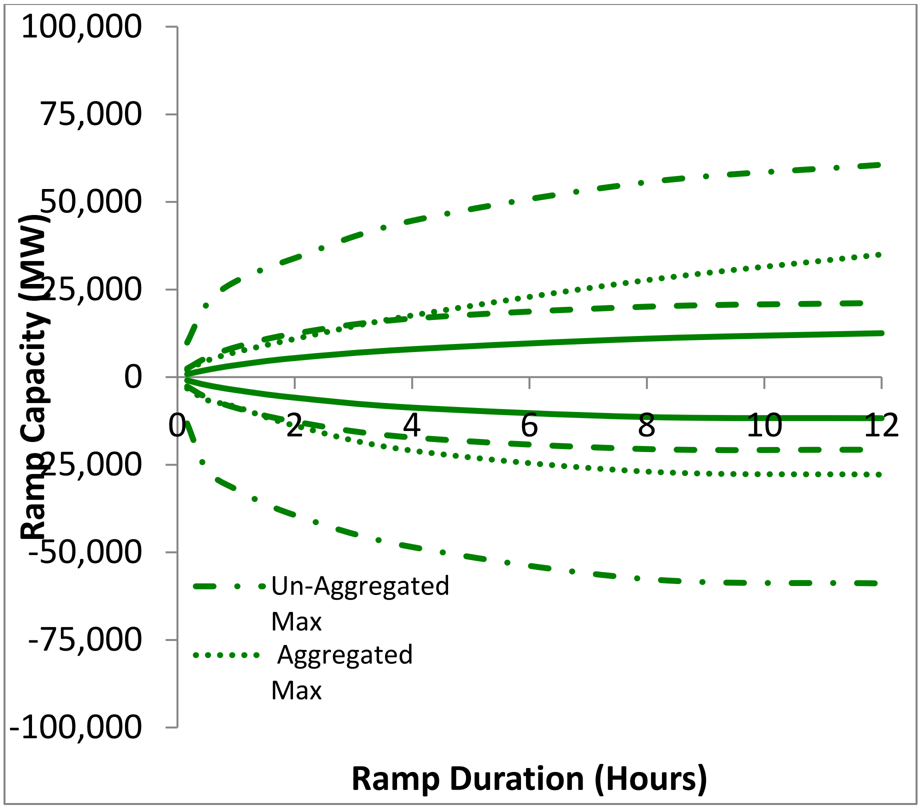


Figure 32. Footprint daily wind maximum ramping requirements

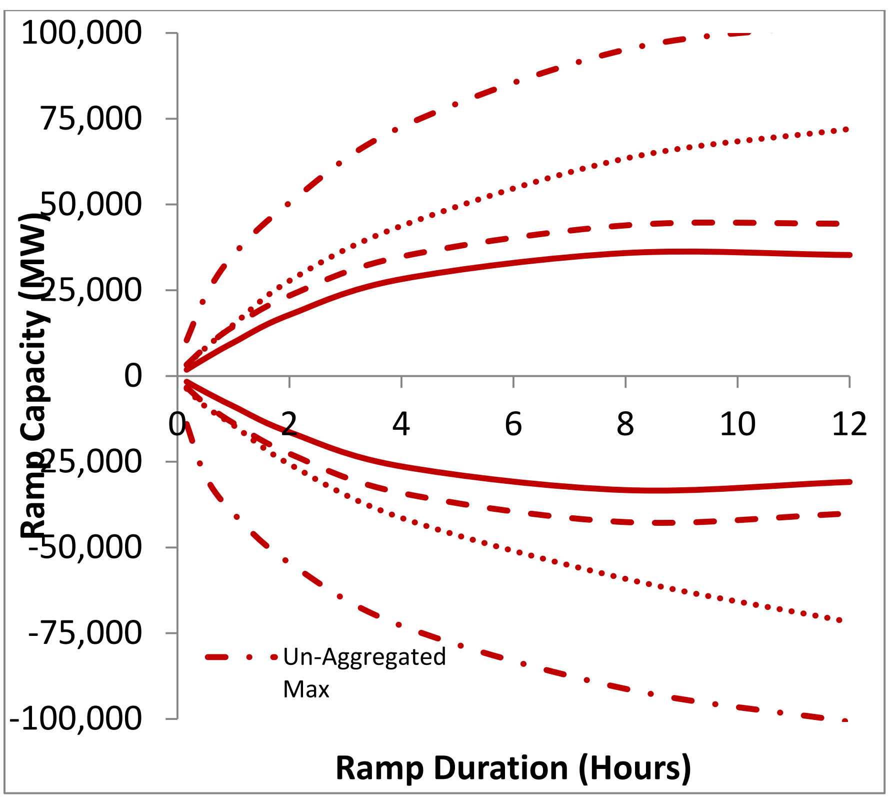


Figure 33. EDT footprint daily net load maximum ramping requirement

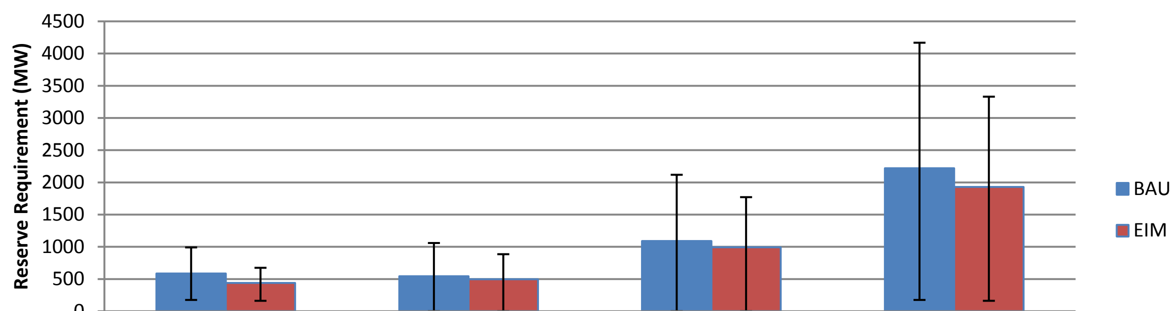
5.4 Regional EIM Scenario Results

Results in the previous section show how reserves are affected when the entire study footprint operates as a single EIM. We also evaluated the effect of operating three distinct regional EIMs in the same footprint.

5.4.1 Columbia Grid EIM

Columbia Grid was evaluated as an EIM with all of the members participating and also with BPA not participating in the EIM. Figure 34 shows the net reserve requirement reduction results for Columbia Grid with all of the members participating in the EIM.

Reserve reduction for a Columbia Grid EIM is relatively modest compared to the full footprint and the other regional EIMs. This is primarily due to the relatively high correlation between wind sites in the footprint with approximately 73% of the nameplate (measured as maximum zonal output not actual machine nameplate) located in the BPA Western Montana zone. This dilutes much of the advantage of aggregating the wind across the regional EIM. Total regulation is reduced by 25% over each of the Columbia Grid BAs operating independently. Total reserves are reduced from 2,221 MW to 1,929 MW, or about 13%.



	Total Reg	Spin	Non-spin	Total
BAU	586	545	1090	2221
EIM	439	497	993	1929

Figure 34. Net reserve savings for Columbia Grid regional EIM

Figure 35 shows the load and net load ramp savings seen by implementing the regional EIM. The savings are relative to ramping that would be seen in the same set of BAs without the EIM.

For net ramps, the maximum up-ramp reduction seen is about 13%, and down-ramp is about 20%. Ramping energy or average ramp saving is about 15%. The average ramp is reduced by 60 MW. For load ramps, the maximum up-ramp reduction is 11%, and down is 7%. The average ramp savings is about 3%, or 7 MW.

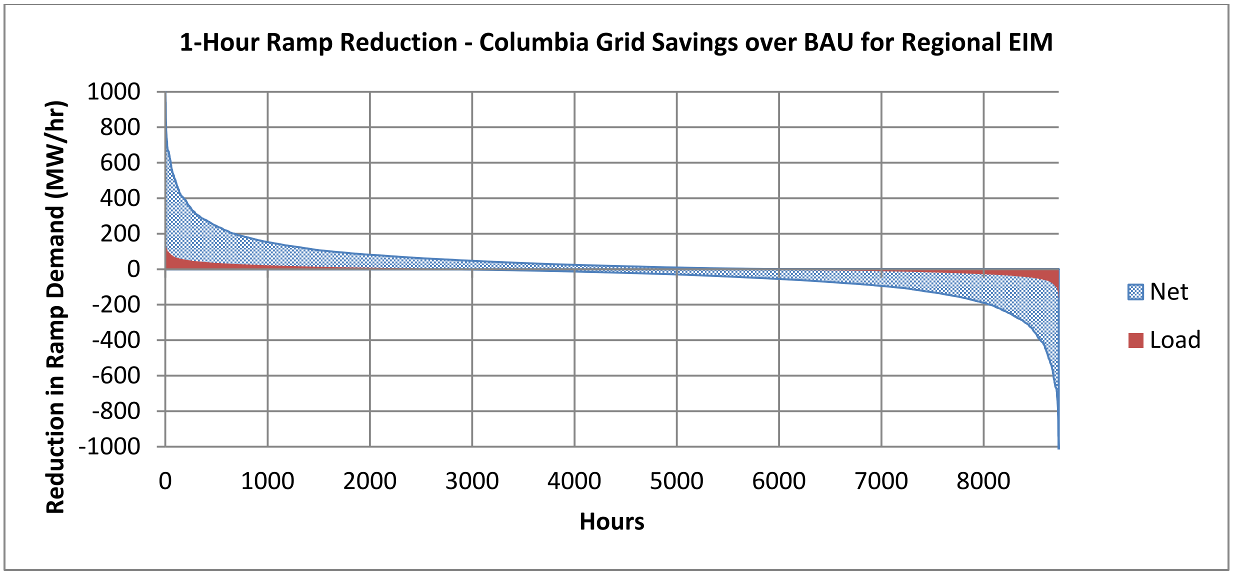


Figure 35. Columbia Grid EIM 1-hour ramp savings

Figure 36 shows the ramp savings for a typical week. The net savings are much larger than the load only because the load in Columbia Grid is highly correlated and the wind is less so, resulting in net ramp reductions of greater magnitude.

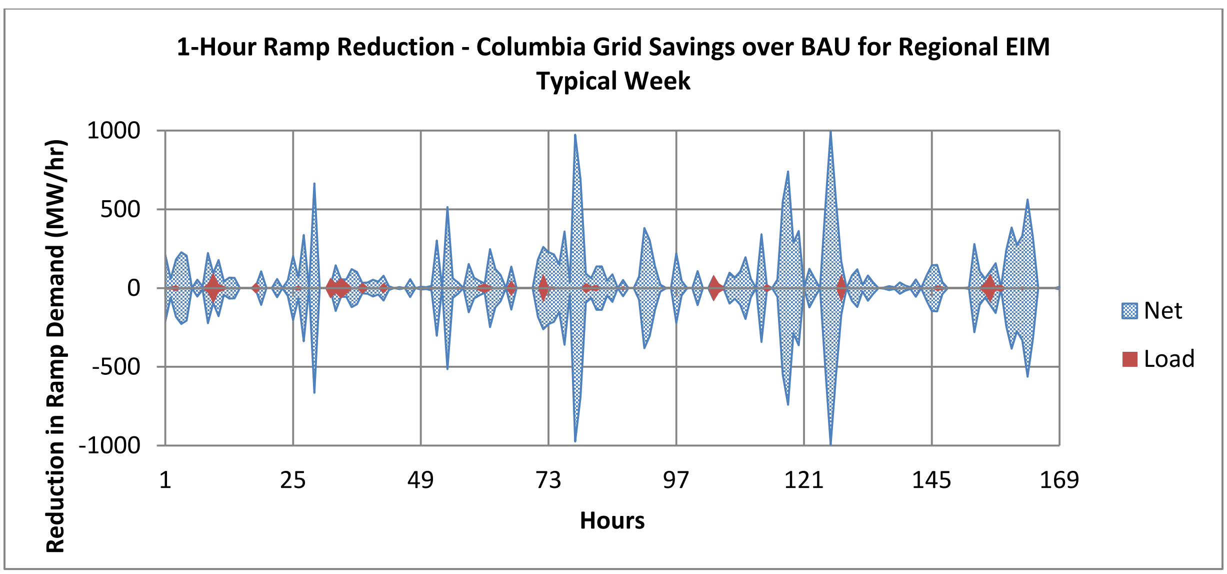


Figure 36. Columbia Grid EIM ramp savings over a typical week

Figure 37 and Figure 38 show the average timing of net ramps seen in Columbia Grid and the timing of the ramp savings. The ramp timing shows the typical high ramp rate in the morning with the ramp continuing into the afternoon before dropping in the evening. The ramp savings plot does not show a clear trend as to when ramps are reduced because it is dominated by wind ramp reductions.

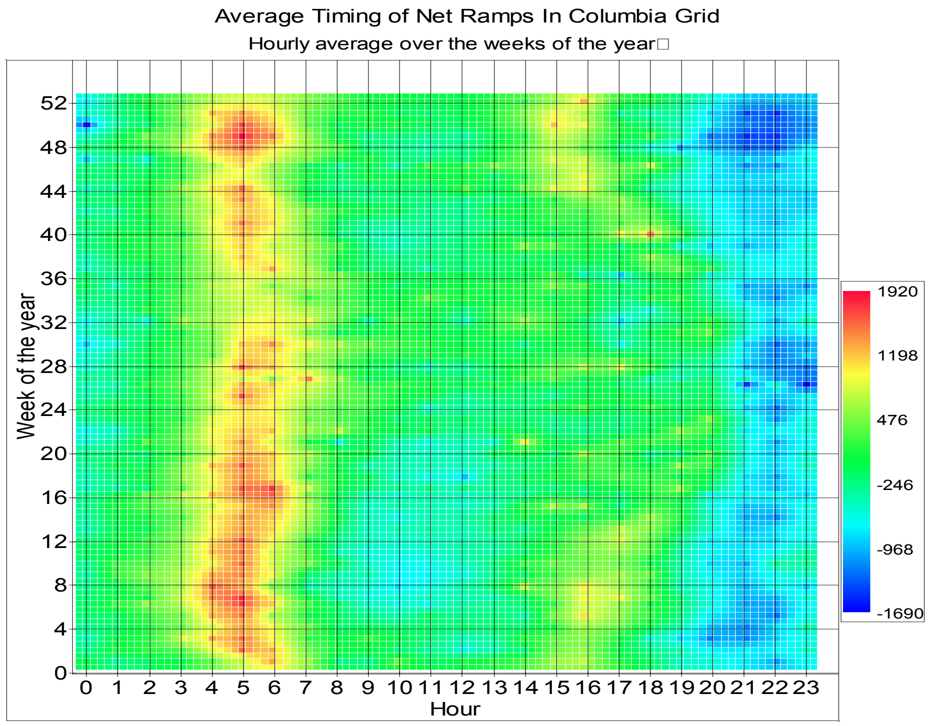


Figure 37. Average timing of net ramps in Columbia Grid

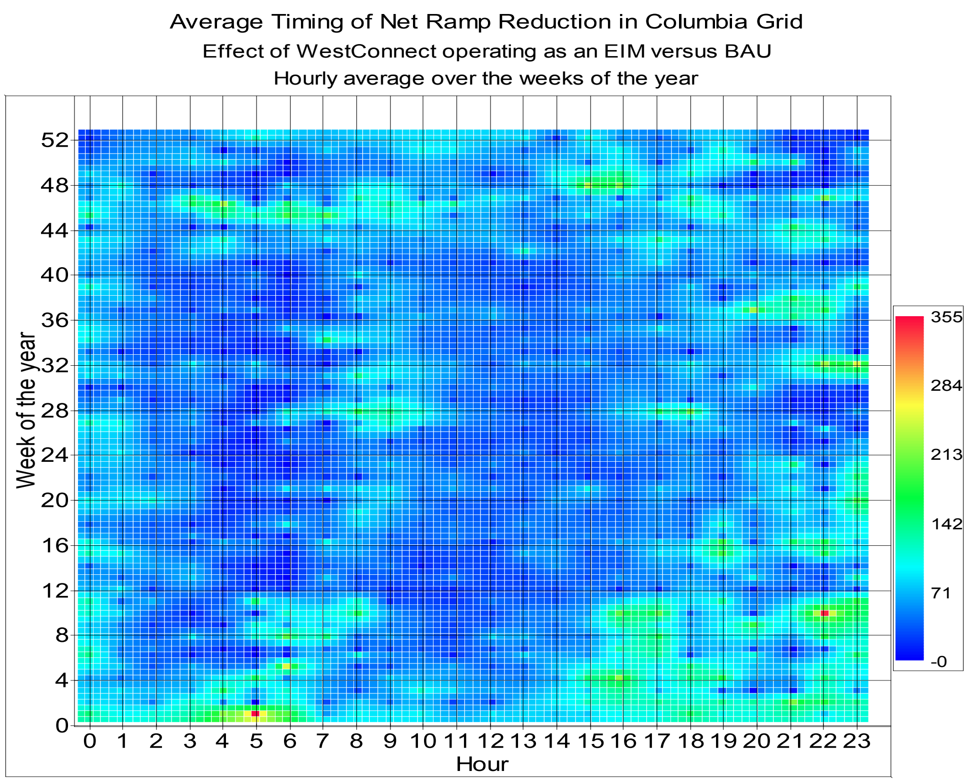
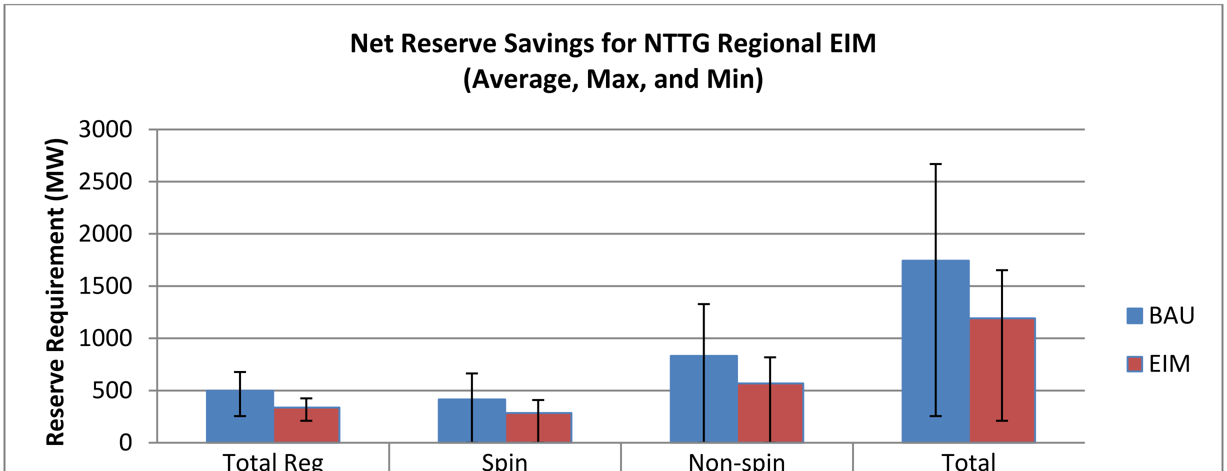


Figure 38. Average timing of net ramp savings in Columbia Grid

5.4.2 Northern Tier Transmission Group EIM

NTTG was evaluated as a regional EIM. Figure 39 shows the net reserve requirement reduction results for NTTG with all of the members participating in the EIM.

For NTTG, the savings are more substantial because of additional diversity in the wind resources in the region. The wind is spread across a large area without large concentrations. Net regulation requirement is reduced from 497 MW on average to 338 MW, a 32% reduction. Average total net reserves are reduced from 1,744 MW to 1,191 MW, also a 32% reduction.



	Total Reg	Spin	Non-spin	Total
BAU	497	416	831	1744
EIM	338	284	569	1191

Figure 39. Net reserve reductions from NTTG regional EIM

Figure 40 shows the load and net load ramp savings seen by implementing the regional EIM. The savings are relative to ramping that would be seen in the same set of BAs without the EIM.

For net ramps, the maximum up-ramp reduction seen is about 29%, and down-ramp is about 31%. Ramping energy or average ramp saving is about 15%. The average ramp is reduced by 259 MW. For load ramps, the maximum up-ramp reduction is 10%, and down is 9%. The average ramp savings is about 3%, or 8 MW.

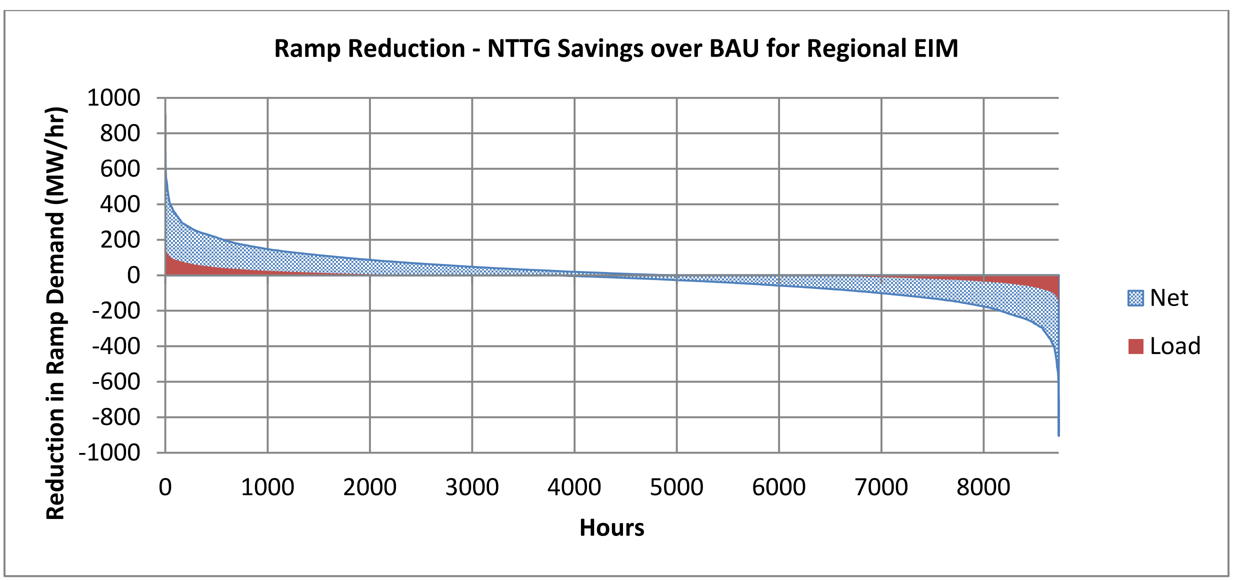


Figure 40. NTTG EIM 1-hour ramp savings

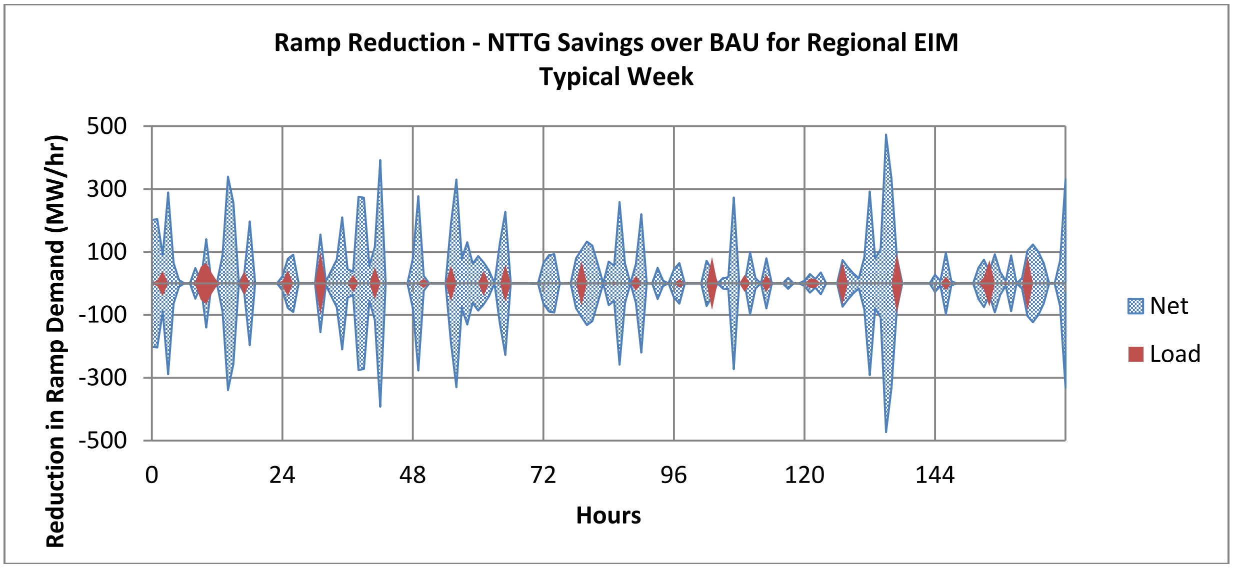


Figure 41. NTTG regional EIM ramp savings over a typical week

Figure 42 and Figure 43 show the average timing of net ramps seen in NTTG and the timing of the ramp savings. The ramp timing shows the typical high ramp rate in the morning with the ramp continuing into the afternoon and an evening bump in the winter weeks. The ramp savings plot does show a trend, with the sharpest reductions in early evening.

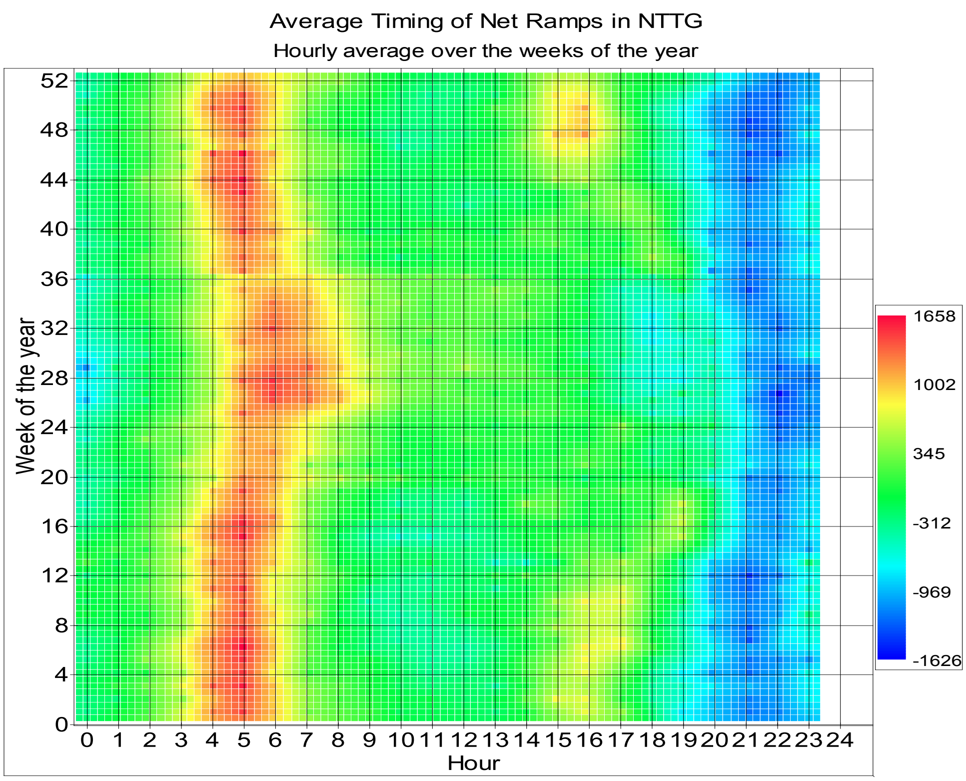


Figure 42. Average timing of net ramps in the NTTG

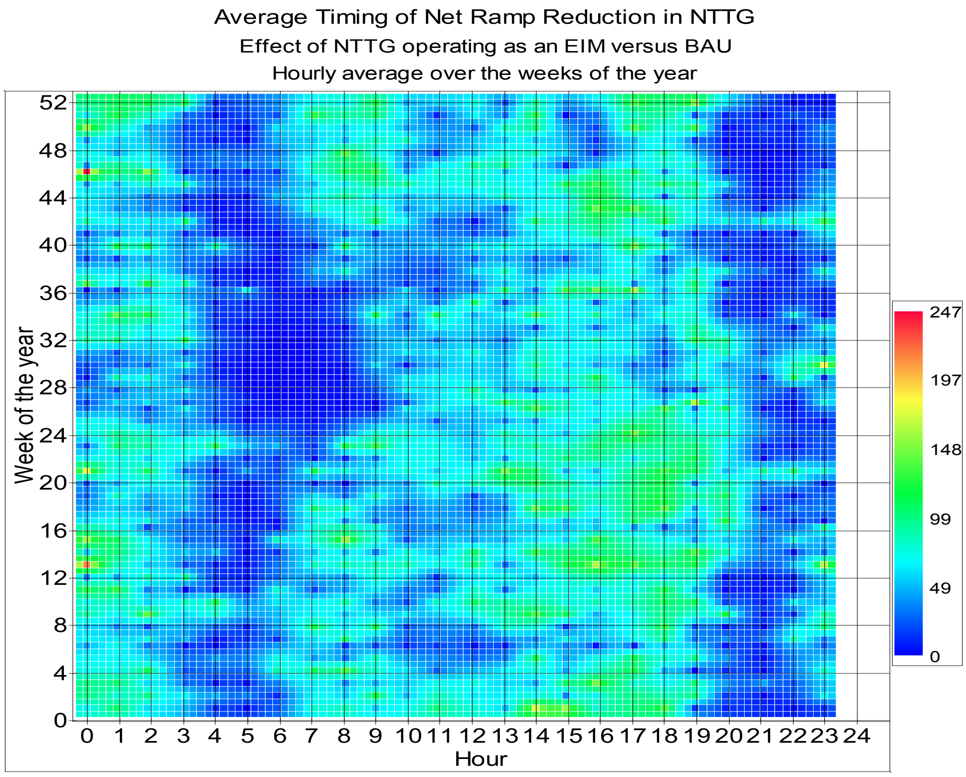
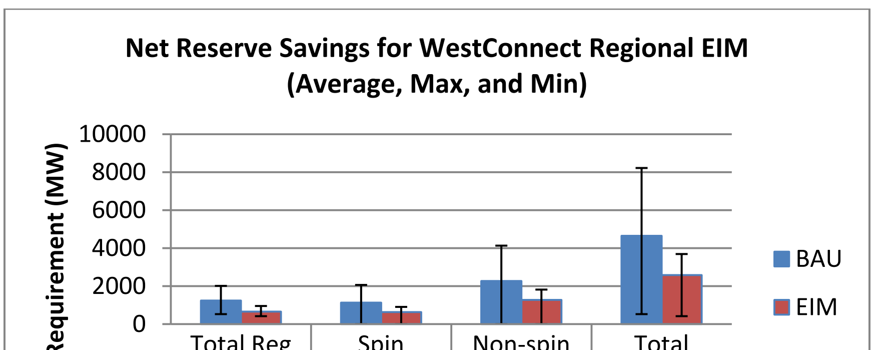


Figure 43. Timing of ramp savings in the NTTG regional EIM

5.4.3 WestConnect EIM

WestConnect was evaluated as an EIM with all of the members participating and also with three regions of WAPA not participating in the EIM. Figure 44 shows the net reserve requirement reduction results for WestConnect with all of the members participating in the EIM.

Of the three regional EIM implementations modeled, WestConnect realizes the greatest benefits both in absolute and relative terms. This is due to the large load and footprint of the region and high geographic diversity of the wind resources. Net load regulation is reduced from 1,242 MW for the BAs operating independently to 662 MW for the EIM, a 50% reduction. Total net reserve requirements are reduced from 4,649 MW to 2,579 MW for the EIM, a 45% reduction.



	Total Reg	Spin	Non-spin	Total
BAU	1242	1136	2271	4649
EIM	662	639	1278	2579

Figure 44. WestConnect regional EIM net reserve reductions

Figure 45 shows the load and net load ramp savings seen by implementing the regional EIM. The savings are relative to ramping that would be seen in the same set of BAs without the EIM.

For net ramps, the maximum up-ramp reduction seen is about 47%, and down-ramp is about 48%. Ramping energy or average ramp saving is about 29%. The average ramp is reduced by 270 MW. For load ramps, the maximum up-ramp reduction is 13%, and down is 16%. The average ramp savings is about 6%, or 35 MW.

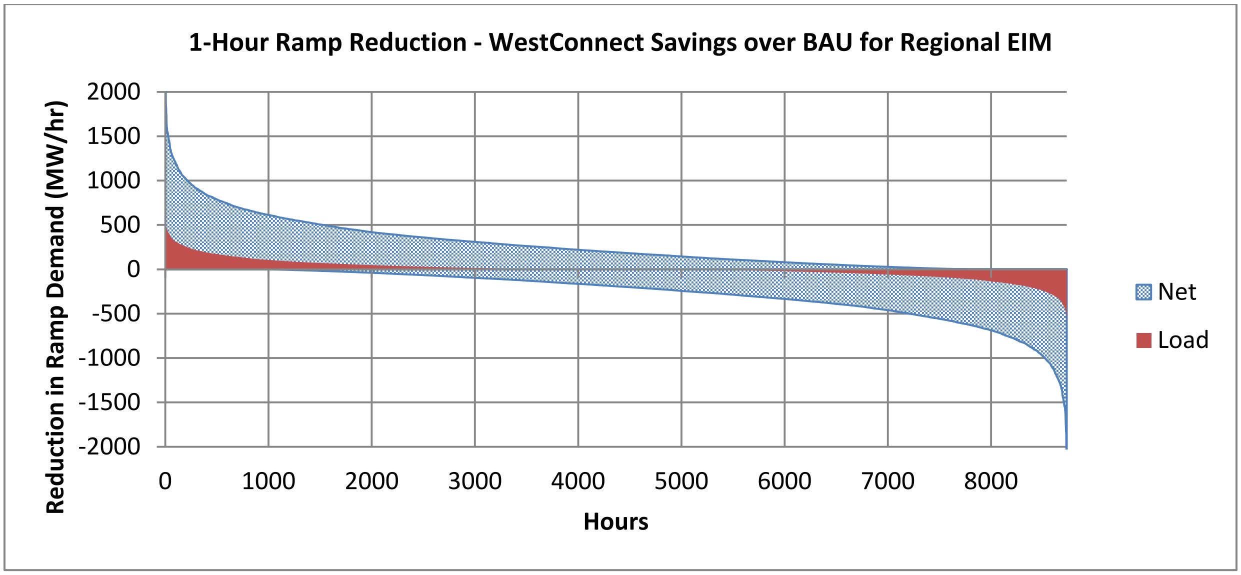


Figure 45. WestConnect EIM 1-hour ramp savings

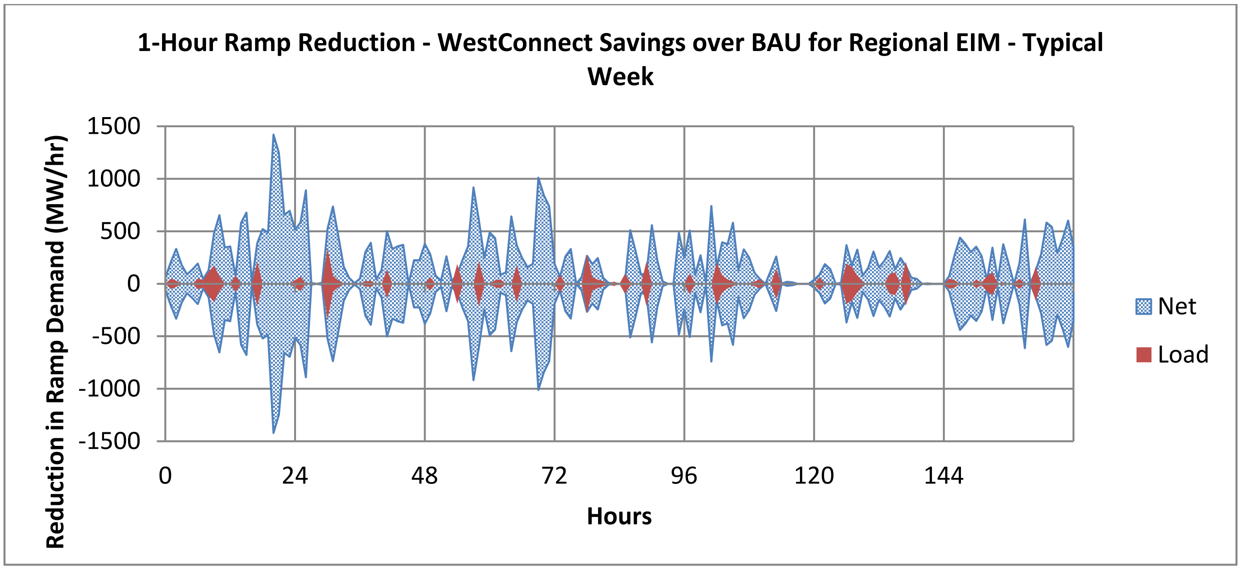


Figure 46. WestConnect EIM ramp savings over a typical week

Figure 47 and Figure 49 show the average timing of net ramps seen in WestConnect and the timing of the ramp savings. The ramp timing shows the typical high ramp rate in the morning with the ramp continuing into the afternoon and an evening bump in the winter weeks. The ramp savings plot does show a clear trend for the sharpest reductions: early evening.

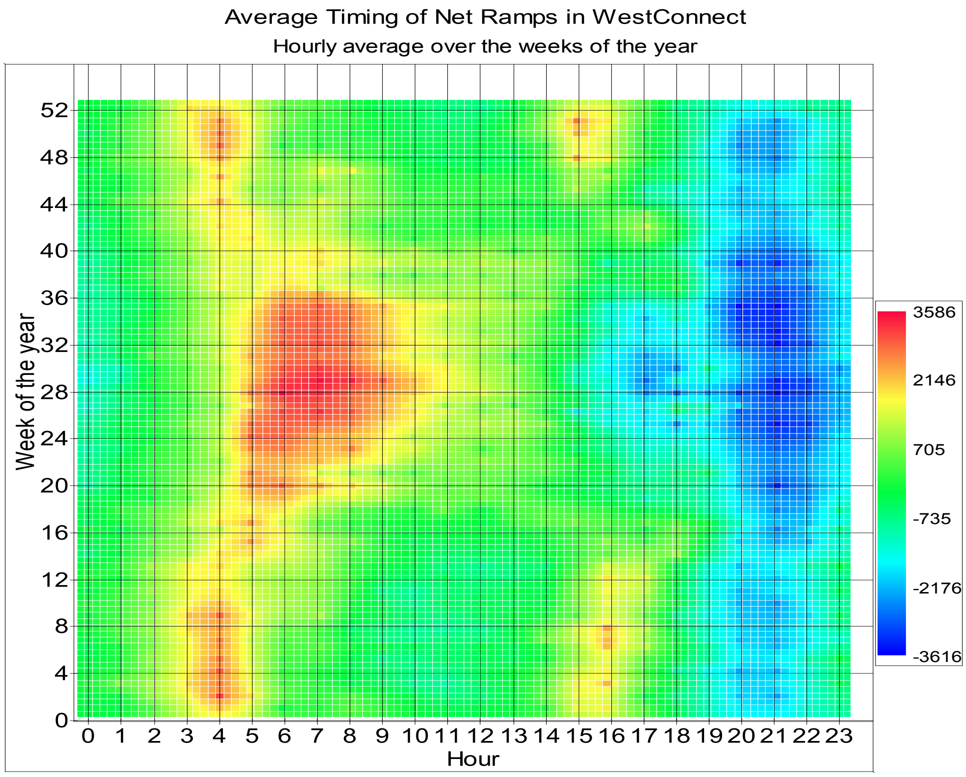


Figure 47. WestConnect regional EIM ramp timing

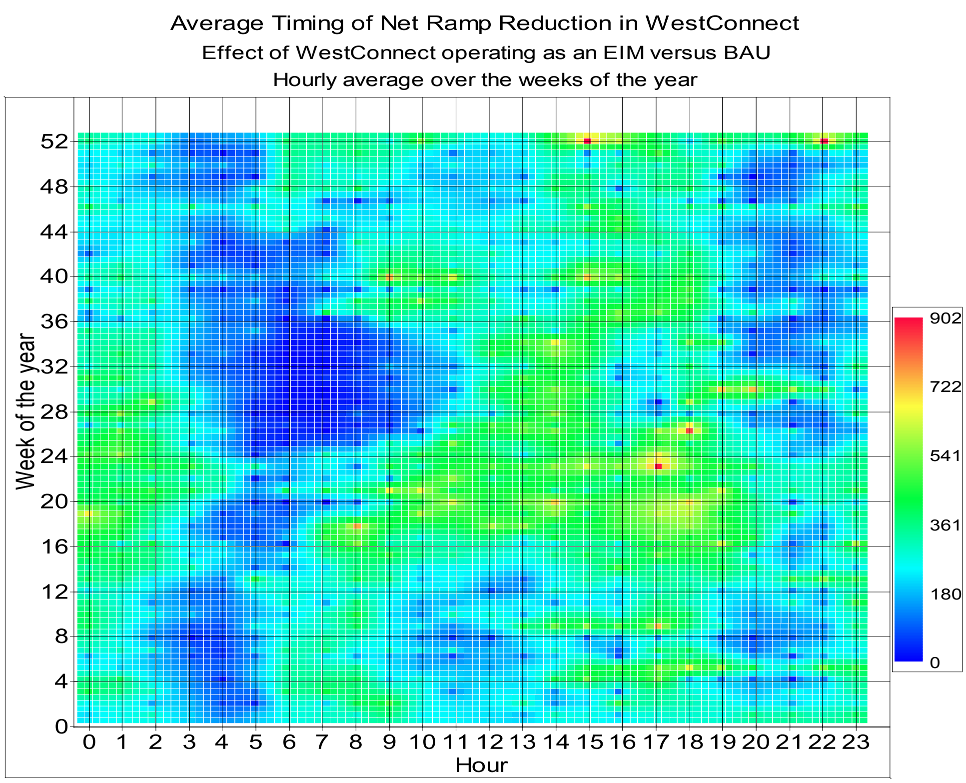


Figure 48. Timing of ramp savings in the WestConnect regional EIM

5.5 Results with BPA and WAPA Not Participating in EIM

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

As part of this analysis, it was necessary to calculate the value of participation in the EIM structures to BPA and WAPA. This would be calculated as the reserve reductions left on the table by not participating. To do this, it is necessary to calculate the proportion of saving that the two areas can claim from the overall savings of the footprint EIM. A method using a share of net variability was devised. This measure weights the benefits to areas with higher variability.

Net variability, for the purposes of this calculation, is defined as the standard deviation of net load. The net load is calculated for each BA in the footprint and the standard deviation calculated and tabulated. The sum of the net variability is formed and a ratio calculated for each BAs share. The result of this calculation is that BPA has a 13.7% share and WAPA an 8.3% share of the footprint EIM. BPA has a 66% share of the Columbia Grid EIM and WAPA has a 14.9% share of the WestConnect EIM. Using average or peak load to apportion the reserves savings yielded similar results.

5.5.1 BPA Not Participating

As we saw with the full Columbia Grid EIM, the savings are somewhat less than seen for the other EIMs relative to the total size. BPA represents around 40% of the load and around 90% of the total wind in Columbia Grid. Removing BPA from the EIM further reduces the reductions, as can be seen in Figure 49. Note that BPA reserves are not included in either set of bars as they are assumed to be managing their variability independently.

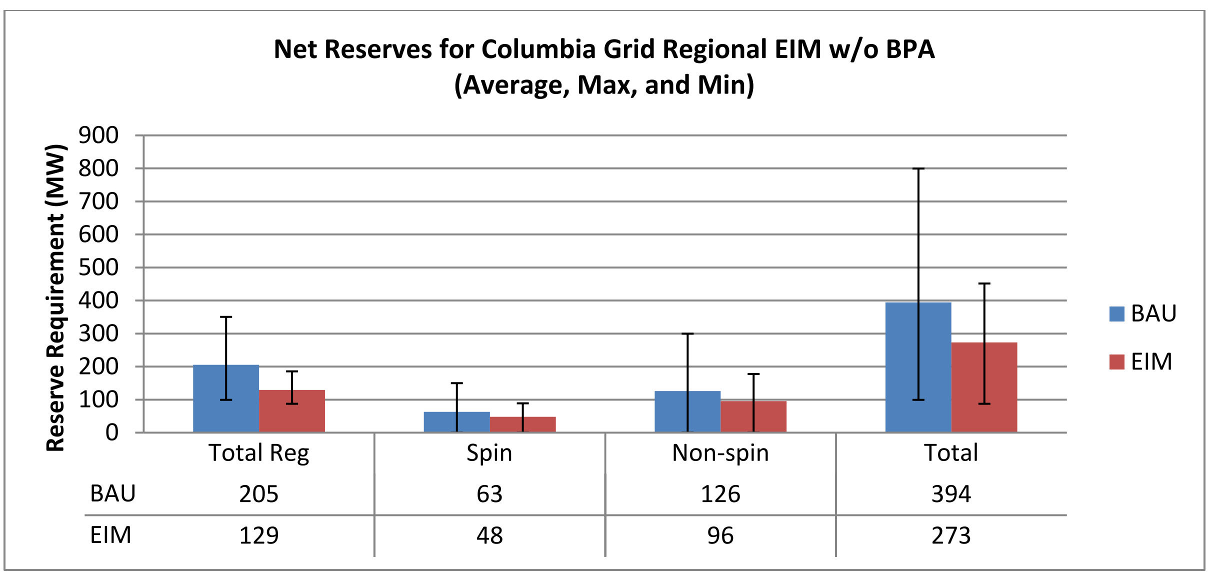


Figure 49. Net reserve requirements for Columbia Grid regional EIM without BPA

When BPA participates in the Columbia Grid regional EIM, significant reserve requirement reductions can be realized. Table shows this effect. The first column shows the reserve requirement responsibility for BPA if participating in the EIM. The second shows the requirement when BPA operates on its own, as is does today. Finally, the last columns show the savings that could be realized for BPA if it participated in the EIM. While the effect on the other participants was shown to be modest, the savings to BPA are significant, cutting regulation requirements by more than one-third. Figure 50 shows the summary of the average reserve requirements for BPA in or out of the Columbia Grid regional EIM.

Table 7. BPA Reserve Requirements in or out of Regional EIM

	Portion of Regional EIM Requirement	Individual Requirement	Unrealized Savings	
	MW	MW	MW	%
BPA (Columbia Grid)				
Average Regulation	291	383	92	24%
Max Regulation	447	635	188	30%
Average Total Reserves	1,278	1,829	551	30%
Max Total Reserves	2,206	3,363	1,157	34%

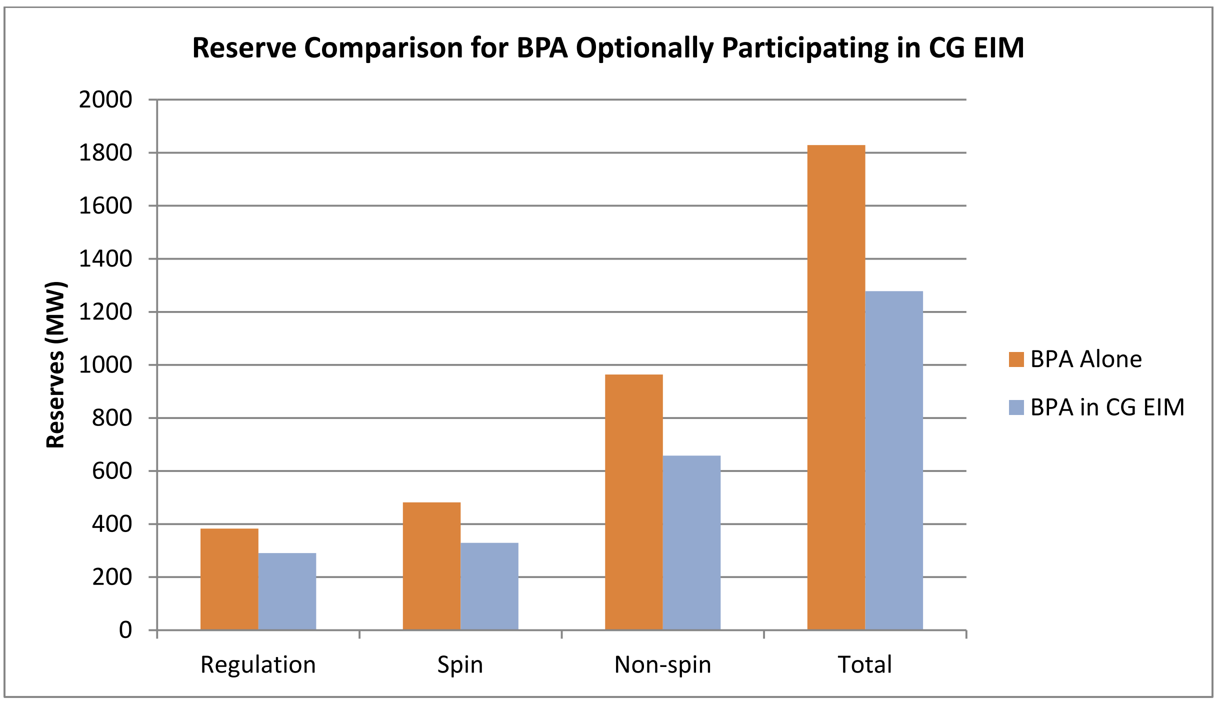


Figure 50. Reserve requirements for BPA alone and participating in Columbia Grid EIM

Figure 51 summarizes the reserve requirement results for Columbia Grid EIM with and without BPA participating. In the figure, the bars represent the following conditions:

- CG BAU is the operation of the Columbia Grid members independently managing the variability in their own regions. This is the sum of the member requirements.
- CG wo BPA BAU is the operation of the Columbia Grid members without BPA's contribution to the total requirements.

- CG Regional EIM is the implementation of a regional EIM for all members of the Columbia Grid
- CG wo BPA EIM is the Columbia Grid EIM operating with all members except BPA.

Because BPA dominates the variability in the Columbia Grid, the cases in which BPA is not involved show relatively low requirements compared to the cases with BPA.

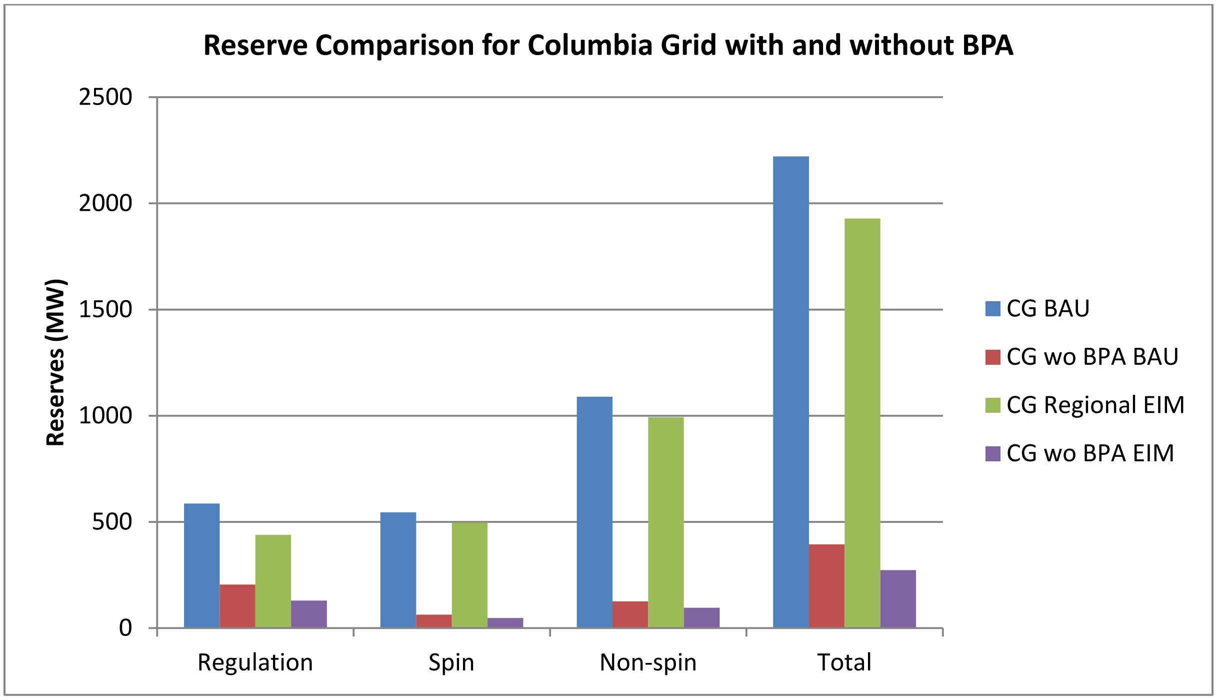


Figure 51. Summary of average reserve for Columbia Grid with and without BPA

In addition to the reserve savings not realized by BPA, there are also ramp consequences. Figure 52 shows a comparison of the ramp requirements for BPA when managing its net ramps itself and when participating with a Columbia Grid EIM. As seen with the reserves, the ramp savings are less than in other regions for BPA because BPA dominates the variability and wind ramping seen in Columbia Grid. The possible reduction in BPA ramping by participating in the EIM ranges from about 33% at short durations to 15% at longer ramp lengths.

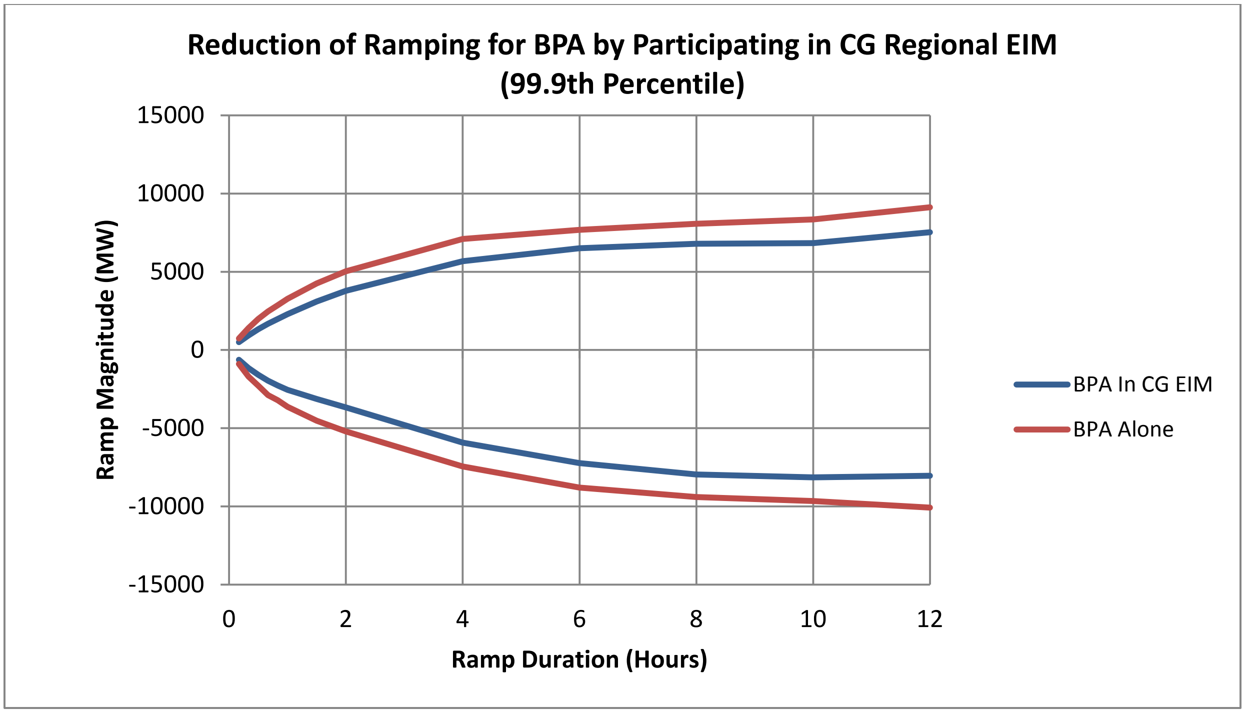
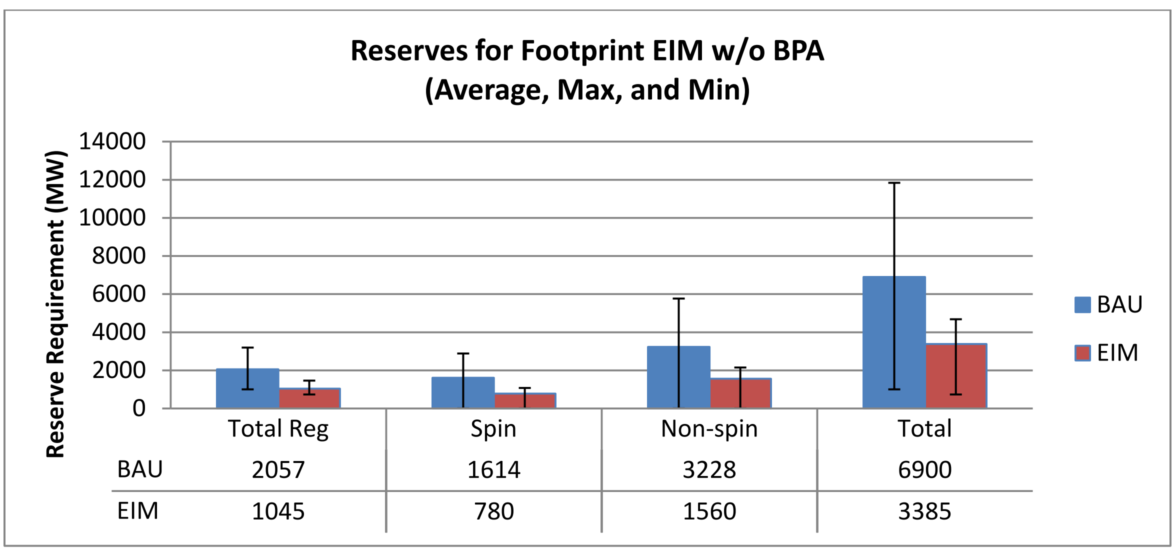


Figure 52. Ramping savings for BPA by participating in Columbia Grid EIM

The full-footprint EIM case was also evaluated with BPA not participating. When the full-footprint EIM is operated without BPA, there is still a very significant reduction in reserves, as seen in Figure 53. Note that BPA reserve responsibilities are not shown as part of either set of bars. They are assumed to be operating independently.



	Total Reg	Spin	Non-spin	Total
BAU	2057	1614	3228	6900
EIM	1045	780	1560	3385

Figure 53. Reserve requirement for the footprint EIM without BPA participation

Without BPA participating in the footprint EIM, the reserve savings are still quite significant to the rest of the BAs in the EIM but are reduced, as shown in Figure 54.

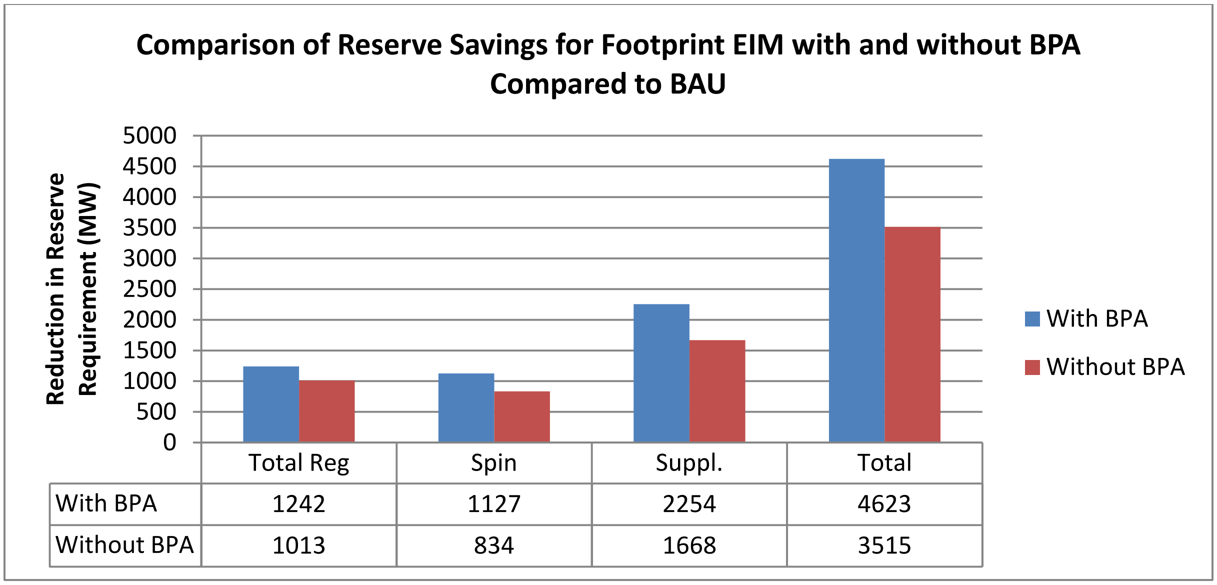


Figure 54. Reserve savings for the footprint EIM with and without BPA

Table 8 shows the effect of participation in the footprint EIM for BPA. The savings are nearly double that for participating in the Columbia Grid EIM. Figure 55 shows a summary for BPA in and out of the footprint EIM.

Table 8. BPA Reserve Requirements in or out of Footprint EIM

	Portion of Footprint EIM Requirement	Individual Requirement	Unrealized Savings	
	MW	MW	MW	% Savings
BPA				
Average Regulation	164	383	219	57%
Max Regulation	222	636	414	65%
Average Total Reserves	561	1,829	1,268	69%
Max Total Reserves	739	3,363	2,624	78%

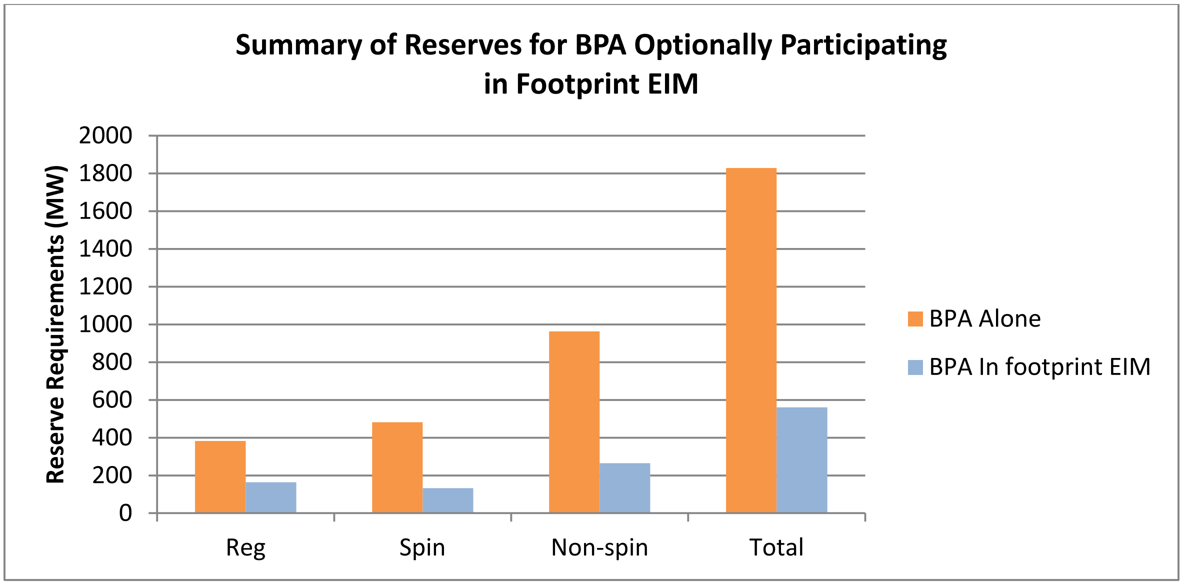


Figure 55. Summary of reserves for BPA alone and in the footprint EIM

A summary of all reserve requirements for the footprint EIM with and without BPA can be seen in Figure 56.

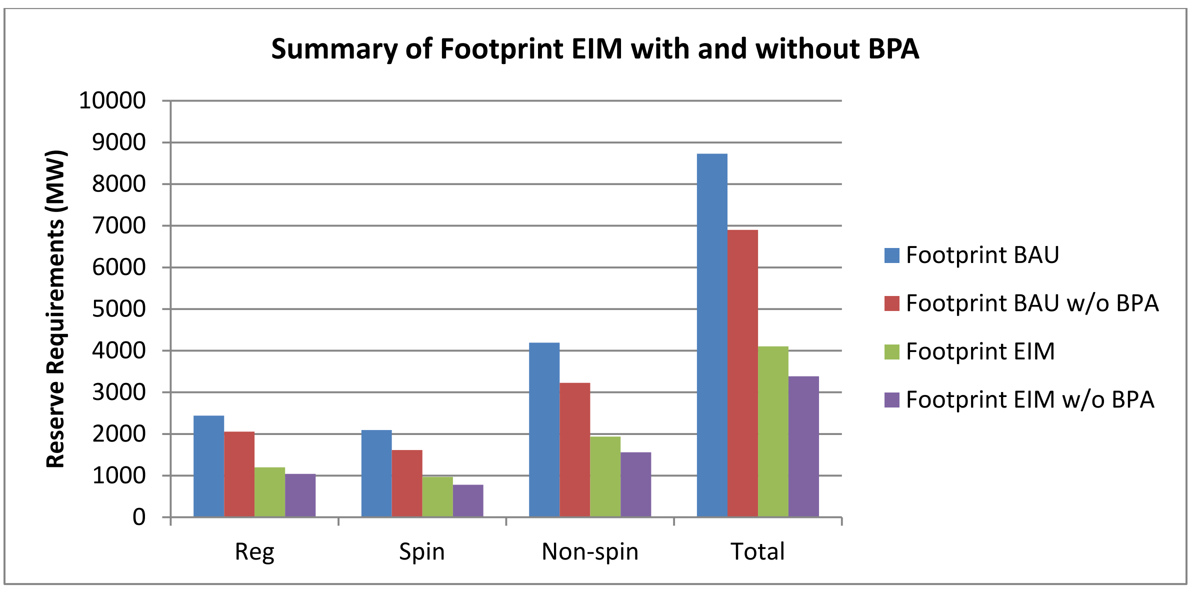


Figure 56. Summary of reserves for the footprint EIM with and without BPA

Figure 57 shows the reduction in ramping duty for BPA. Ramp magnitudes are decreased by more than 70% at short durations to just under 40% at longer durations. These reductions are approximately twice the reductions seen for the Columbia Grid regional EIM.

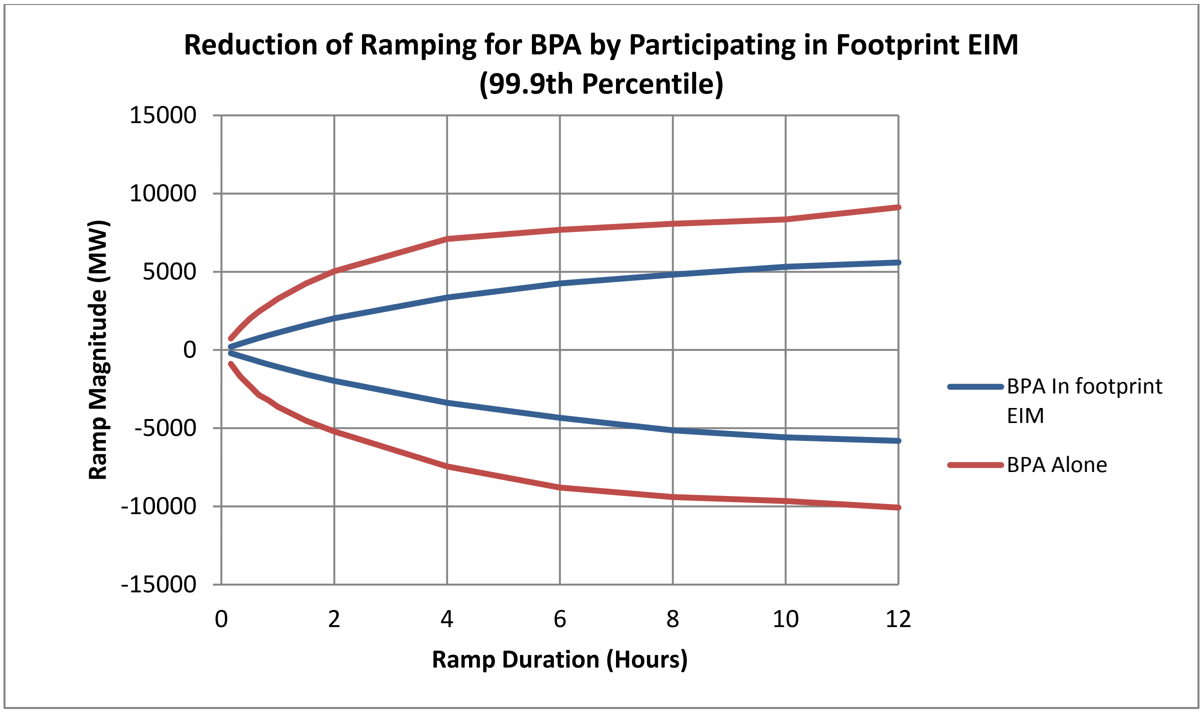


Figure 57. Ramp savings for BPA by participating in the footprint EIM

5.5.2 WAPA Not Participating

The three WAPA regions in the model represent approximately 14% of the load and 22% of the total wind modeled in WestConnect. With these proportions, WAPA participation in the WestConnect EIM contributes a significant amount to the reserve savings for the EIM. Without WAPA, the requirements are also reduced significantly. Figure 58 shows these requirements with WAPA not represented in either set of bars.

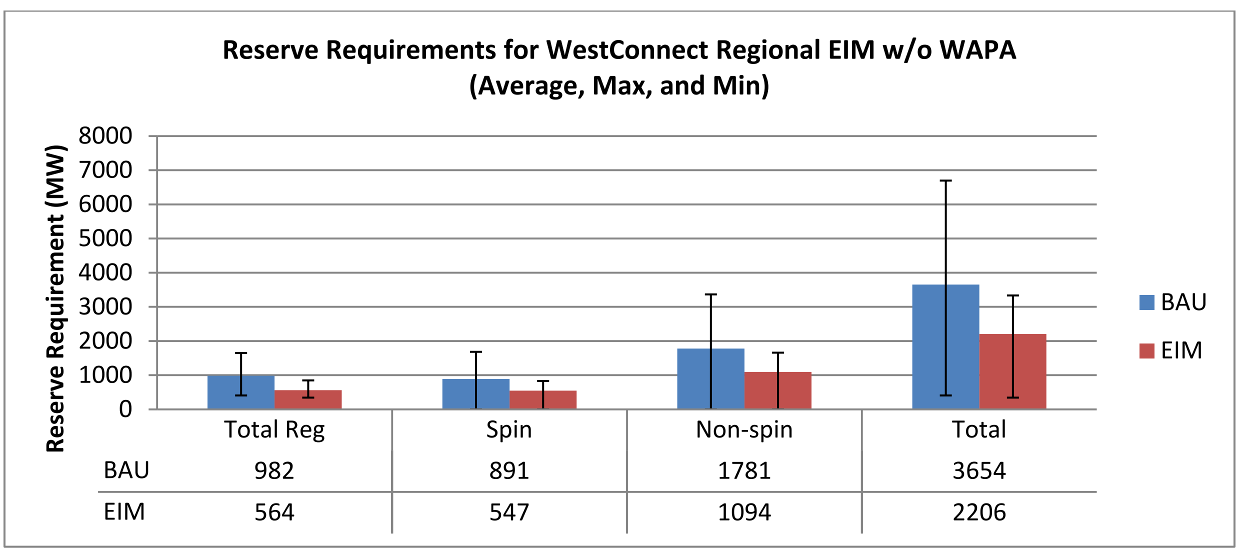


Figure 58. Reserve requirements for WestConnect regional EIM without WAPA participation

When WAPA participates in the WestConnect EIM, very significant reserve requirement reductions can be realized over operating independently. Table shows these significant possible savings. The first column shows the proportion of the total EIM requirements that WAPA would be responsible for based on the net variability apportionment discussed earlier in this section. The second column shows the WAPA requirement when operating as three independent regions. The last columns show the savings that could be realized by operating in the regional EIM. The potential savings are large, with nearly two-thirds reduction in regulation requirement and nearly 75% reduction in total reserves. Figure 59 shows a summary of the average reserve requirements for WAPA in or out of the WestConnect EIM.

Table 9. WAPA Reserve Requirements in or out of WestConnect Regional EIM

	Portion of Regional EIM Requirement	Individual Requirement	Unrealized Savings	
	MW	MW	MW	%
WAPA (WestConnect)				
Average Regulation	98	261	163	62%
Max Regulation	143	364	221	61%
Average Total Reserves	282	996	714	72%
Max Total Reserves	549	1,524	975	64%

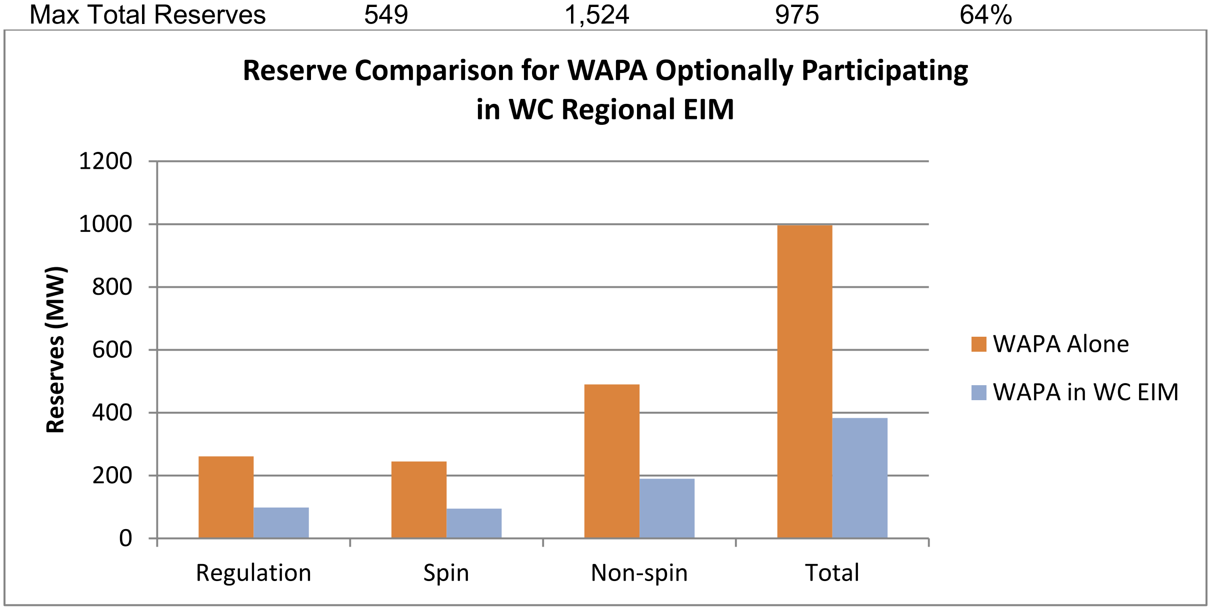


Figure 59. Summary of reserves for WAPA alone or participating in WestConnect EIM

Figure 60 shows the average reserve savings comparing the BAU case to the WestConnect regional EIM without WAPA. The graph shows that the savings reduction is significant for the remaining participants.

- WC with WAPA BAU is the operation of the WestConnect members independently managing the variability in their own regions. This is the sum of the member requirements.

- WC wo WAPA BAU is the operation of the WestConnect members without BPA's contribution to the total requirements.
- WC Regional EIM is the implementation of a regional EIM for all members of the WestConnect.
- WC wo WAPA EIM is the WestConnect EIM operating with all members except WAPA.

While all participants in the EIM benefit when WAPA participates, the benefit seen by WAPA is very significant.

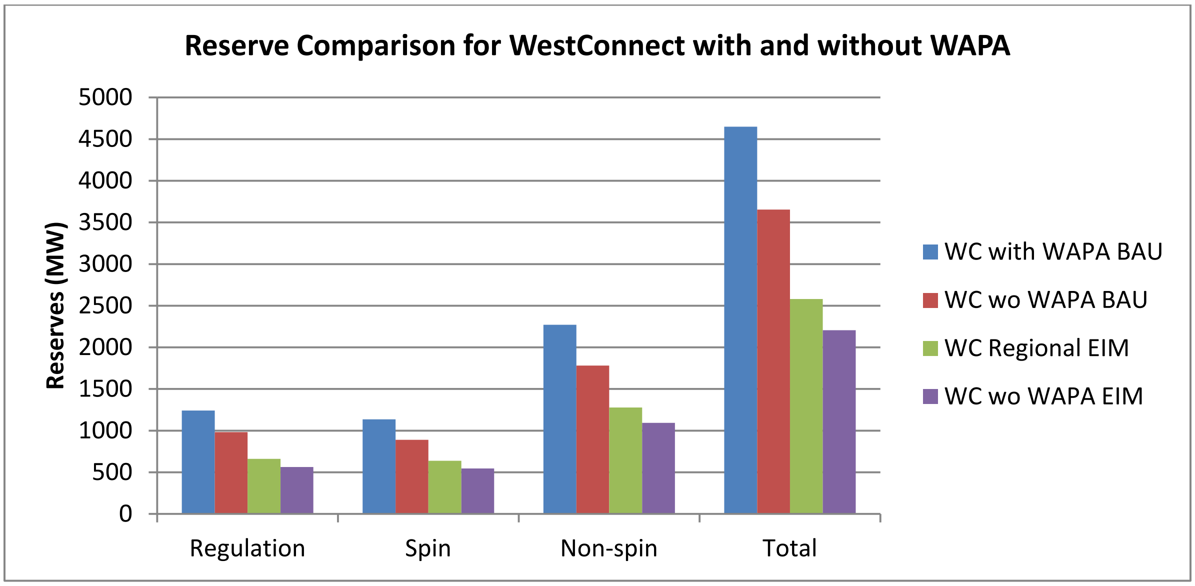


Figure 60. Summary of average reserve for WestConnect with and without WAPA

In addition to the reserve savings not realized by WAPA, there are also ramp consequences. Figure 61 shows a comparison of the ramp requirements for WAPA when managing its net ramps itself and when it participates with a WestConnect EIM. As seen with the reserves, the ramp savings are significant for WAPA. The possible reduction in ramping ranges from about 70% at short durations to 25% to 30% at longer ramp lengths.

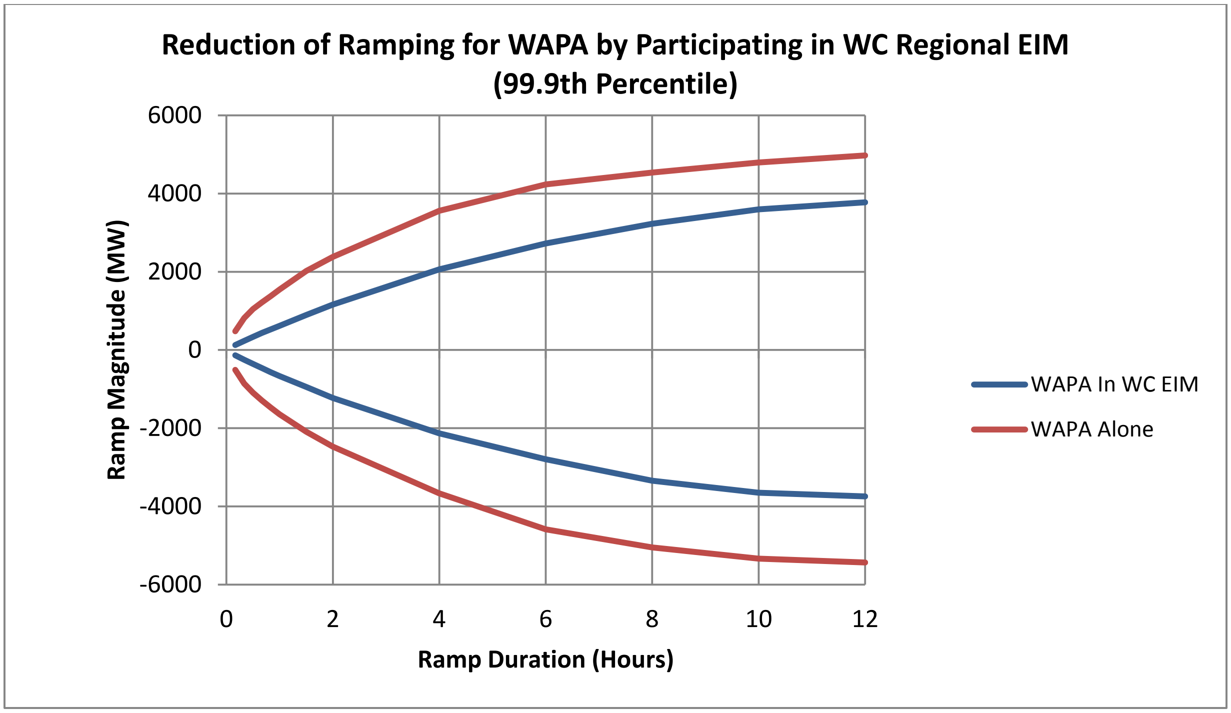


Figure 61. Ramping savings for WAPA by participating in WestConnect regional EIM

When the full-footprint EIM is operated without WAPA, there is still a very significant reduction in reserves, as seen in Figure 62. Note that WAPA reserve responsibilities are not shown as part of either set of bars. They are assumed to operate independently.

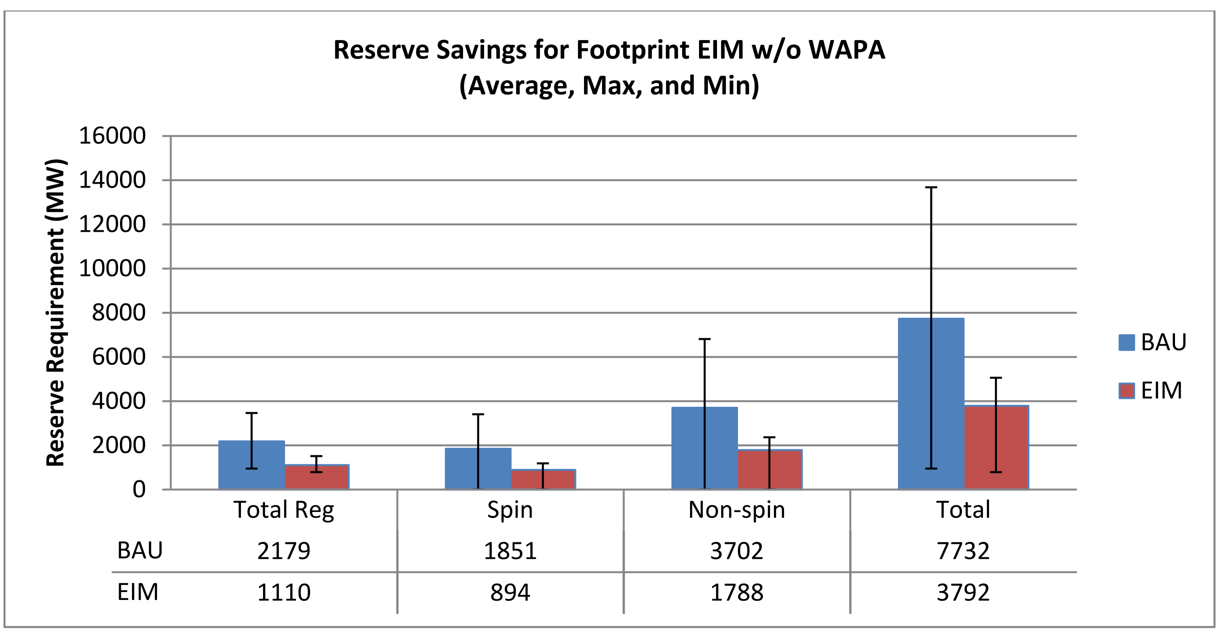


Figure 62. Reserve requirements for the footprint EIM without WAPA participation

Table shows the reserve requirements and savings for WAPA participating in the footprint EIM. The savings are slightly higher for this case compared to WAPA participation in the

WestConnect regional EIM. Figure 63 shows a summary of the average reserve requirements for WAPA in or out of the footprint EIM.

Table 10. WAPA Reserve Requirements in or out of Footprint EIM

	Portion of Footprint EIM Requirement	Individual Requirement	Unrealized Savings	
	MW	MW	MW	% Savings
WAPA				
Average Regulation	100	261	161	62%
Max Regulation	136	364	228	63%
Average Total Reserves	342	996	654	66%
Max Total Reserves	451	1,524	1,073	70%

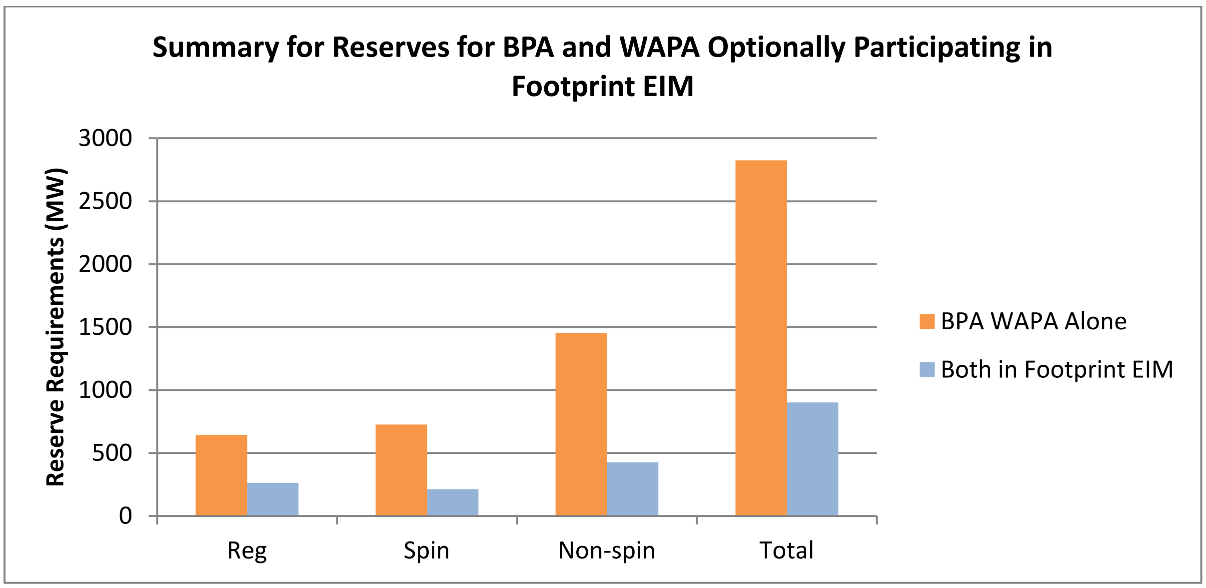


Figure 63. Summary of reserves for WAPA alone and in the footprint EIM

Figure 64 shows a summary of all reserve requirements for the footprint EIM with and without WAPA participation.

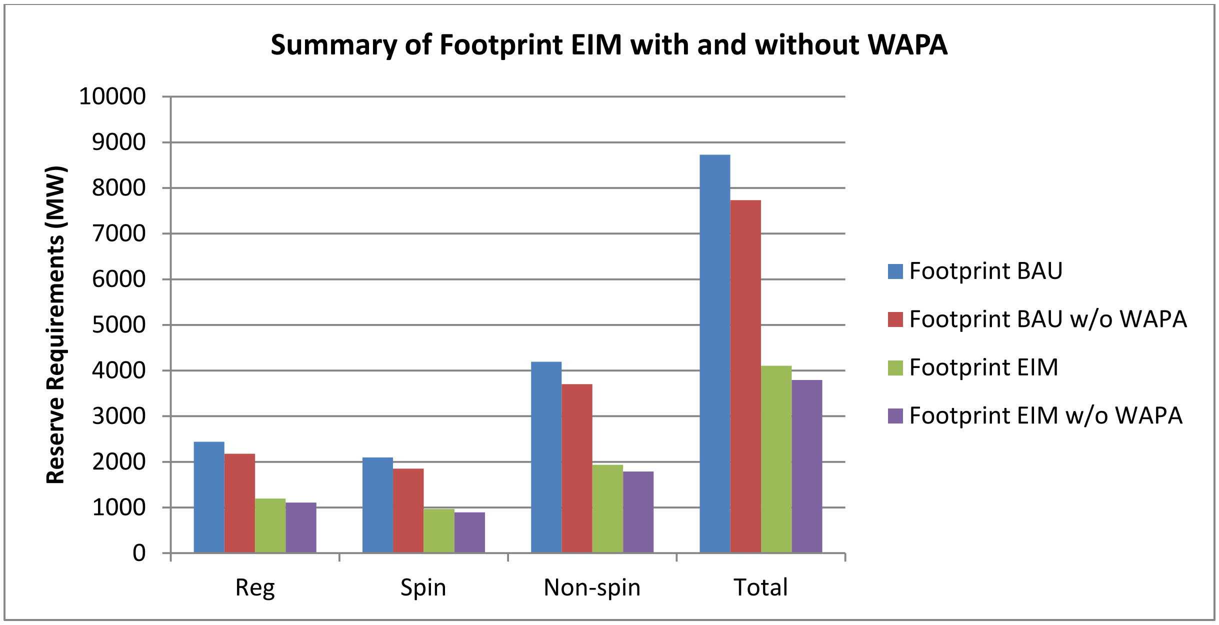


Figure 64. Summary of reserve requirements for the footprint EIM with and without WAPA

Figure 65 shows the reduction in ramping duty for WAPA. Ramp magnitudes are decreased by 75% at short durations and by as much as 35% at longer durations.

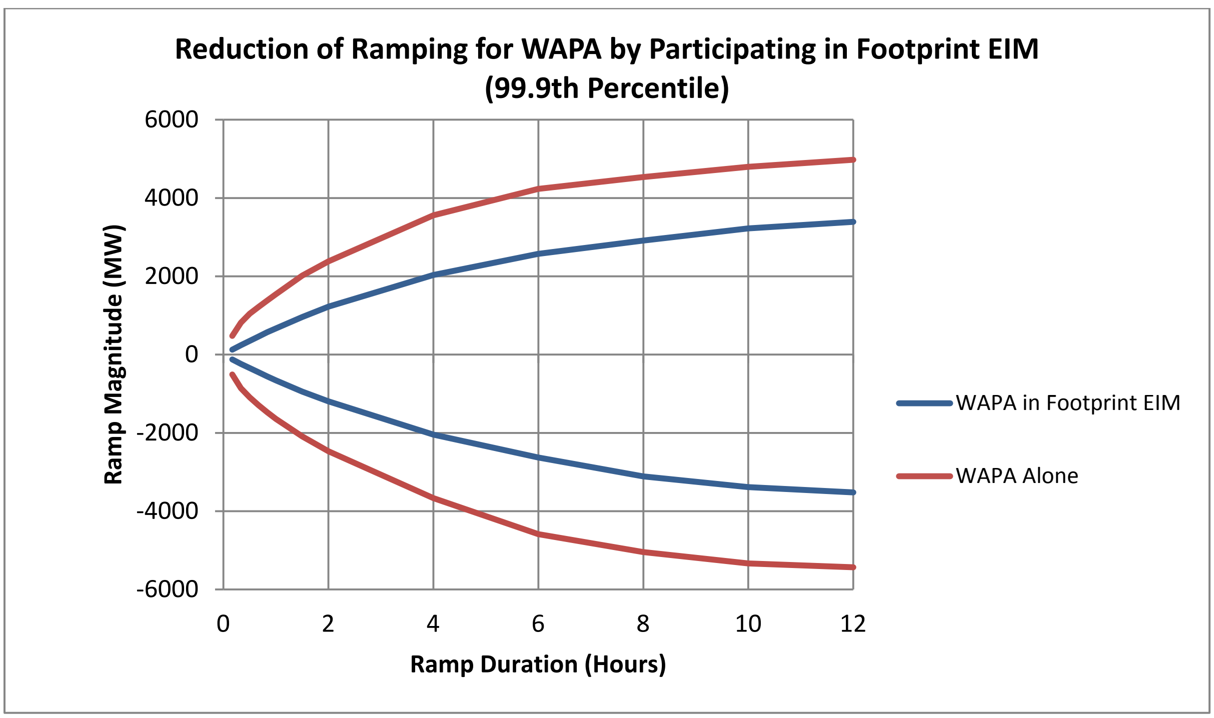


Figure 65. Ramp reduction resulting from WAPA participating in the footprint EIM

5.5.3 BPA and WAPA Not Participating

The case in which neither BPA nor WAPA participate in a footprint-wide EIM was also evaluated. These BAs represent a significant portion of the wind in the entire footprint at approximately 33% of the total wind resource modeled. Figure 66 shows reserve requirements for the footprint with these two BAs not participating in the EIM. There are very significant savings for the remaining participants in the EIM.

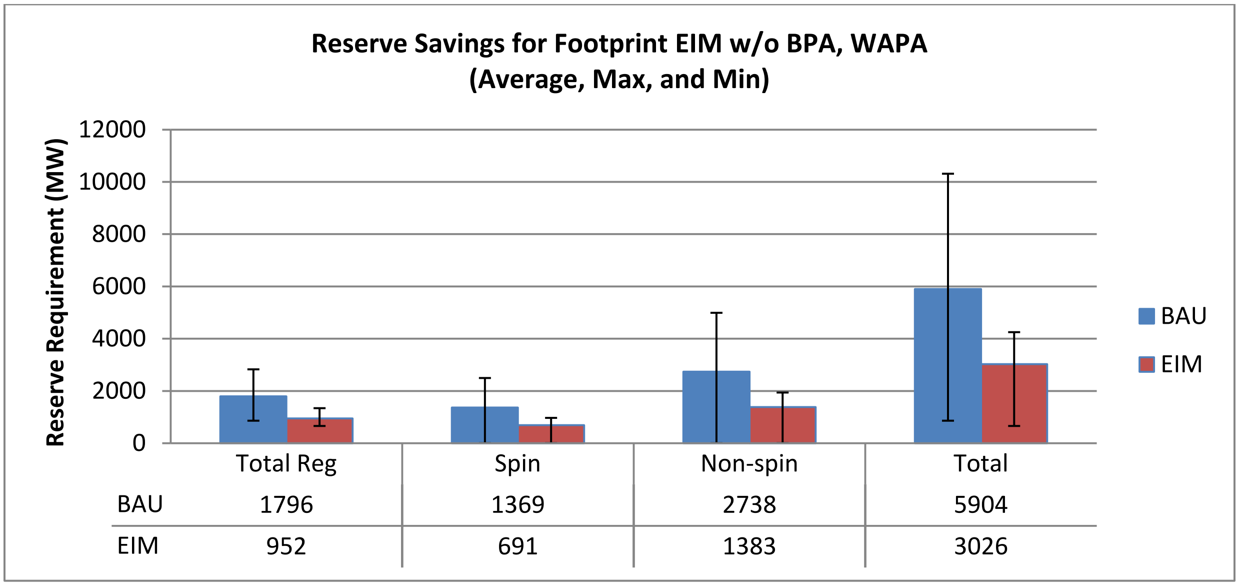


Figure 66. Reserve savings for the footprint EIM without BPA or WAPA participation

The savings for BPA and WAPA participating in the footprint EIM are roughly the sum of the savings for the individual BAs seen in the previous two sections. Figure 67 shows a summary of the average reserves for BPA and WAPA both in and out of the footprint EIM.

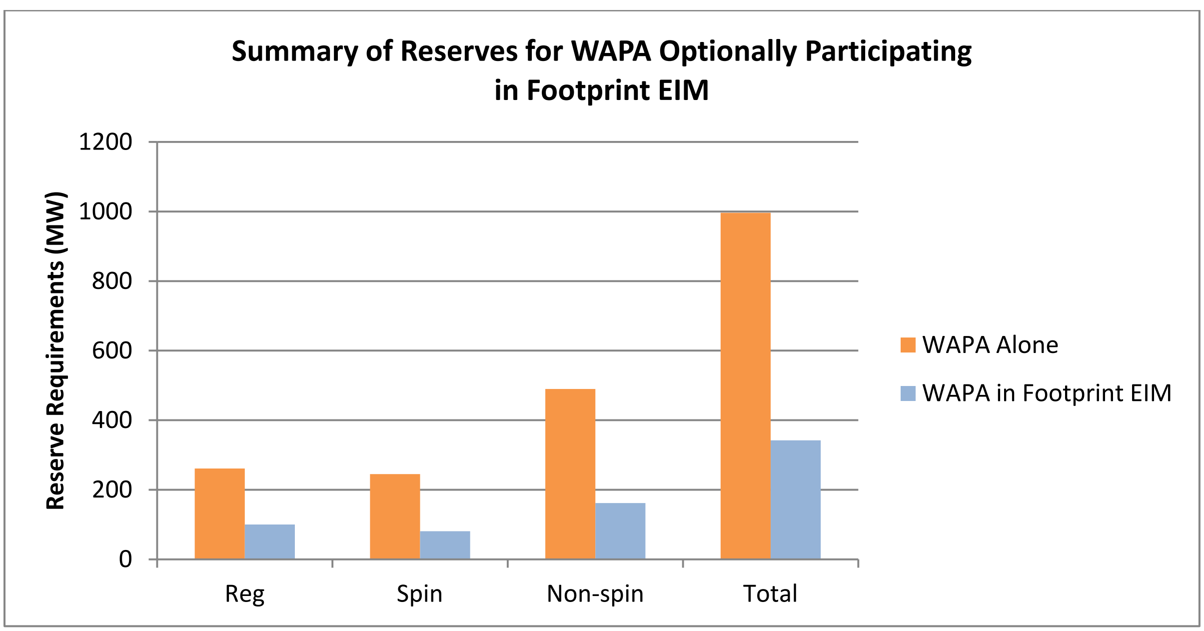


Figure 67. Summary of reserves for WAPA and BPA alone and in the footprint EIM

Figure 68 shows a summary of the reserve requirements for the footprint EIM with and without BPA and WAPA.

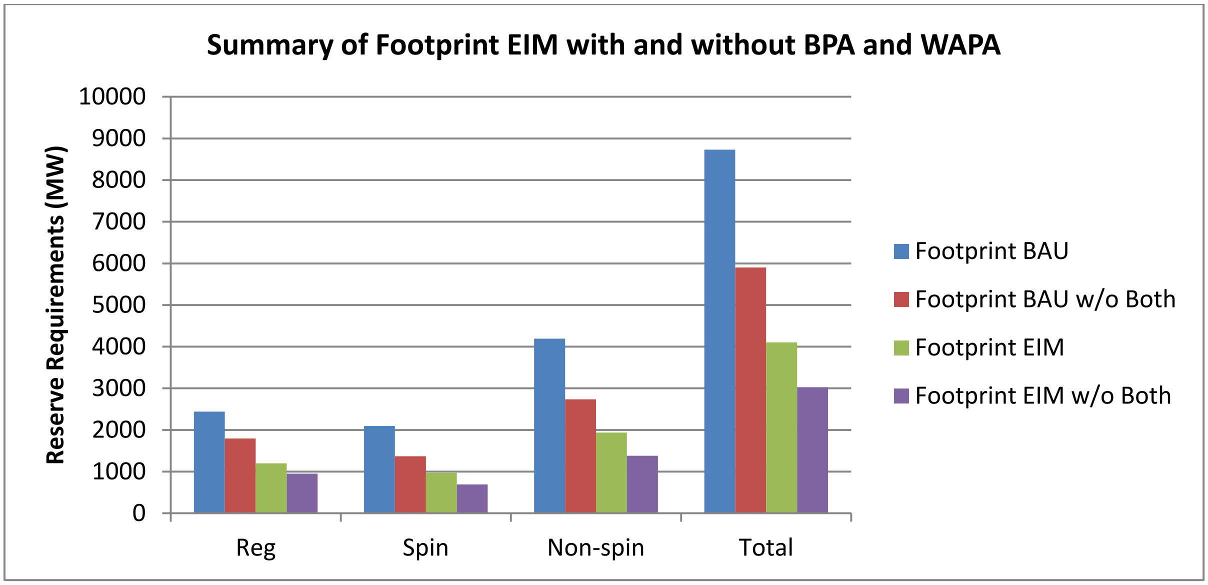


Figure 68. Summary of reserves for the footprint EIM with and without BPA and WAPA

5.6 Results for Wind-Only and Load-Only Balancing Authorities

One possible operating structure for the study footprint with wind energy involves segregating the wind into wind-generation-only balancing authorities (see for example [7]), which have no load. The load would be segregated into load and conventional generation balancing authorities with no wind included.

In a wind-only/load-only BA arrangement, the load BAs would be responsible for balancing their load and would not have any burden in balancing the wind. The wind-only BAs, with no load or any other generation, would be forced to acquire regulating, spin, and non-spin reserves from other market participants. An arrangement such as this exposes all costs of the reserve burden imposed by wind and foregoes the benefits of aggregating wind and load variability and uncertainty.

Three scenarios were evaluated. Two of the scenarios concentrate all wind into a single footprint-wide EIM with the load either in a single footprint-wide EIM or managed by each individual BA as is the current business practice. The third scenario has three wind-only and three load-only EIMs implemented, one each in the defined regional breakdown of Columbia Grid, Northern Tier Transmission Group, and WestConnect.

The results for these scenarios are compared with the BAU scenario in Figure 69. Note that the BAU reference is as defined earlier and models each existing BA as managing its own wind and load. There are very significant savings from these implementations. In fact, they differ from the integrated wind and load EIM implementations only in the load regulation components and the additional increment caused to the total by the load regulation. These results will be compared later in the summary.

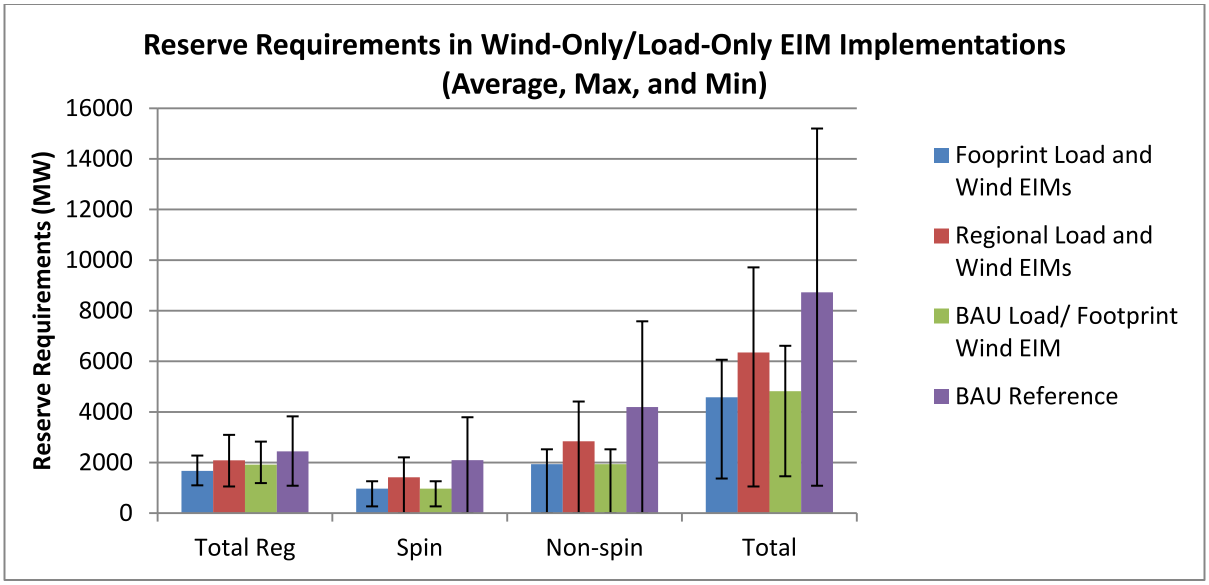


Figure 69. Reserve requirements for wind-only/load-only EIM implementations

With the regulation components small in comparison to the total reserves, those values are difficult to discern. Figure 70 presents the regulation bars in isolation so the detail can be seen.

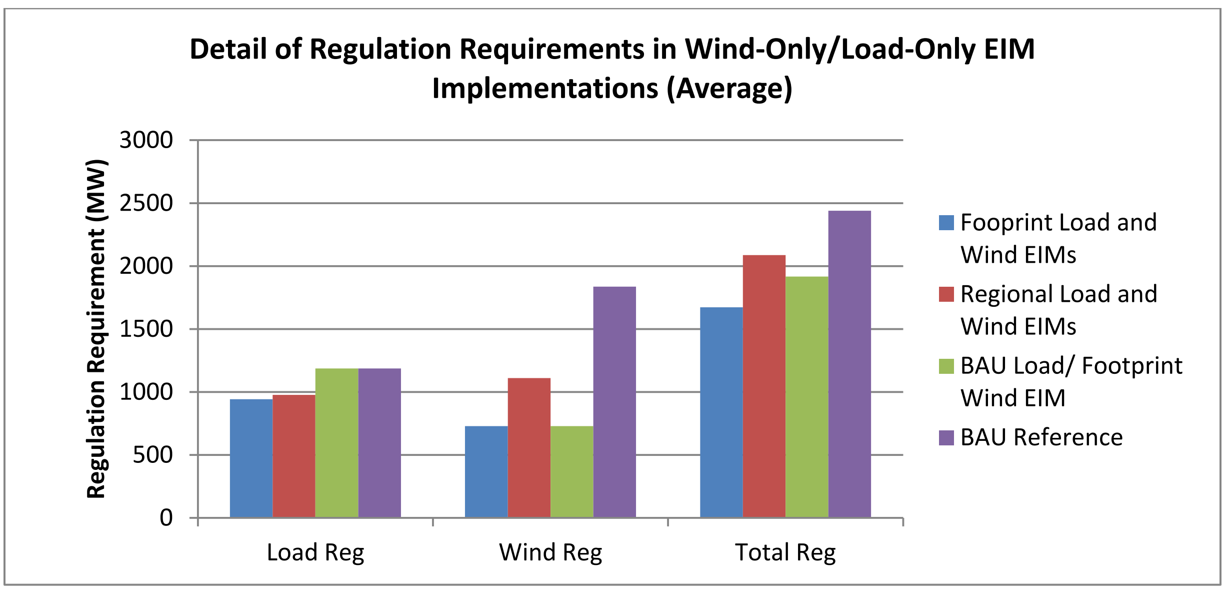


Figure 70. Detail of regulation requirements for wind-only/load-only EIM implementations

Figure 71 shows the reserve reductions for the three wind-only/load-only scenarios over the BAU scenario. The savings are dominated by the scenarios with footprint-wide wind EIM implementations. The load regulation savings contributes an extra 250 MW to total regulation savings.

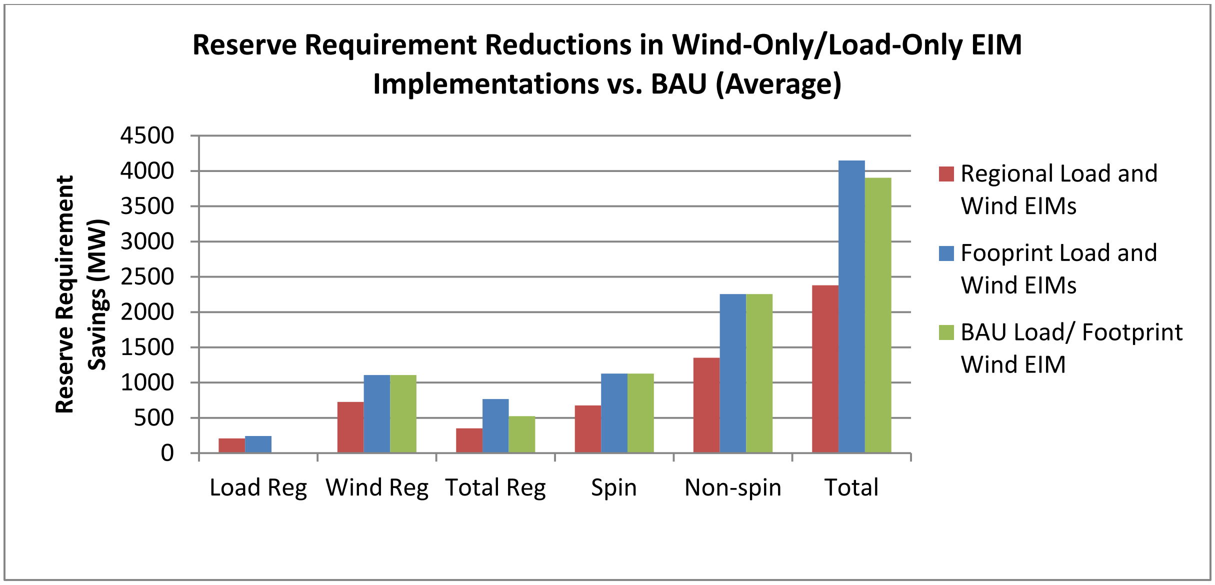


Figure 71. Reserve requirement reductions for wind-only/load-only EIM implementations

5.7 Summary Results

As has been shown, implementation of an EIM over any size region leads to reduction in reserve requirements and ramping demand. As the size of the EIM increases, the benefits to all participants increase because the variability and uncertainty associated with the wind resources are spread across a greater footprint with more diversity.

Figure 72 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 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 the BAU case. Spinning and non-spin reserve requirements are similarly reduced. It is interesting to note that the load-only regulation is also reduced significantly by this aggregation, 21% on average for the footprint EIM.

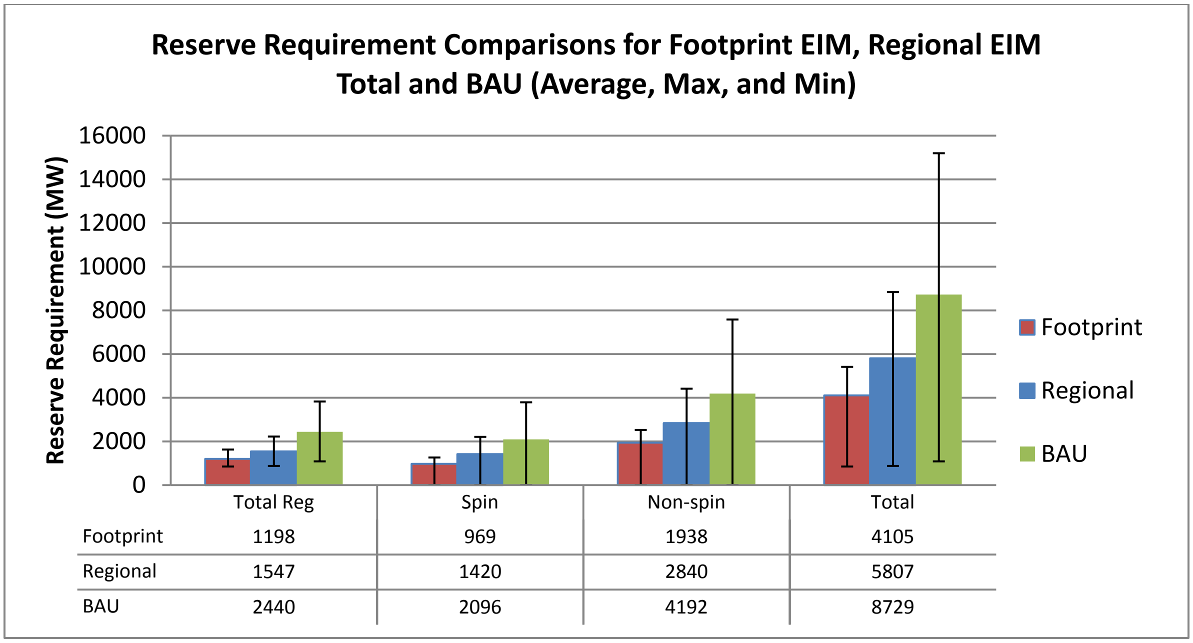


Figure 72. Reserve requirements across EIM implementations

Table 11 shows the reductions in reserve requirements for the footprint and regional EIMs reflected to the footprint level.

Table 11. Reserve Reductions at the Footprint Level Seen in EIM Implementations

		Footprint EIM		Regional EIM	
	BAU	EIM	Reduction	EIM	Reduction
Maximum Value (MW)					
Reg.	3,826	1,626	58%	2,221	42%
Spin	3,791	1,262	67%	2,206	42%
Non-spin	7,582	2,524	67%	4,412	42%
Total	15,200	5,412	64%	8,839	42%
Average Values (MW)					
Reg.	2,440	1,198	51%	1,547	37%
Spin	2,096	969	54%	1,420	32%
Non-spin	4,192	1,938	54%	2,840	32%
Total	8,729	4,105	53%	5,807	33%

At the regional EIM implementation, significant savings are seen also. Table 12 shows a comparison and summary for the three EIM regions considered.

Table 12. Comparison of Reserve Requirements for Regional EIMs (MW)

	Regional EIM								
	Columbia Grid			NTTG			WestConnect		
	BAU	EIM	Reduction	BAU	EIM	Reduction	BAU	EIM	Reduction
Maximum Values									
Reg.	991	674	32%	677	425	37%	2,019	960	52%
Spin	1,059	885	16%	664	409	38%	2,068	912	56%
Non-Spin	2,118	1,771	16%	1,328	818	38%	4,137	1,824	56%
Total	4,167	3,330	20%	2,669	1,652	38%	8,224	3,695	55%
Average Values									
Reg.	586	439	25%	497	338	32%	1,242	662	47%
Spin	545	497	9%	416	284	32%	1,136	639	44%
Non-Spin	1,090	993	9%	831	569	32%	2,271	1,278	44%
Total	2,221	1,929	13%	1,744	1,191	32%	4,649	2,579	45%

It is interesting to note that the load-only regulation is also reduced significantly by this aggregation. Spinning and non-spin reserve requirements are similarly reduced, as seen in Figure 73.

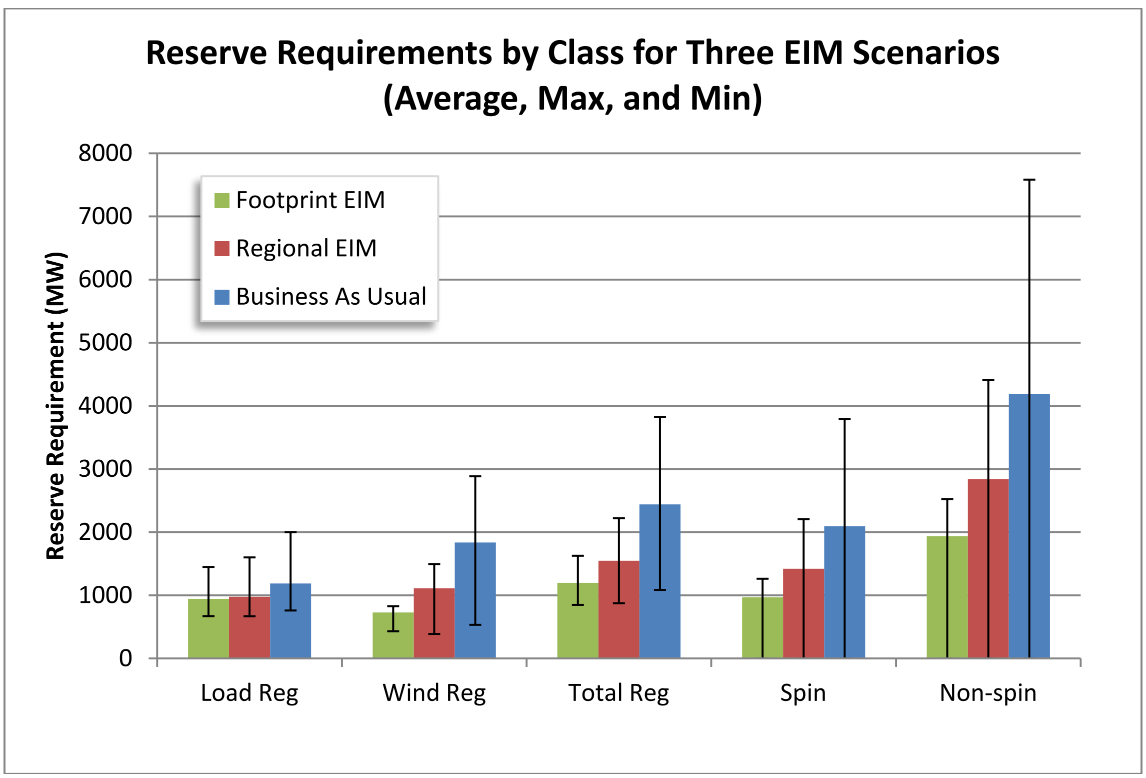


Figure 73. Regulation requirements for various scenarios

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, we ran cases with BPA and Western 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 74 shows, the remaining participants' regulation requirement is reduced to 51% for 10-minute scheduling if either BPA or Western does not participate as opposed to 49% if everyone participates. The non-participant’s requirement is still 100%, however, so the non-participant loses the most. If neither BPA nor Western 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.

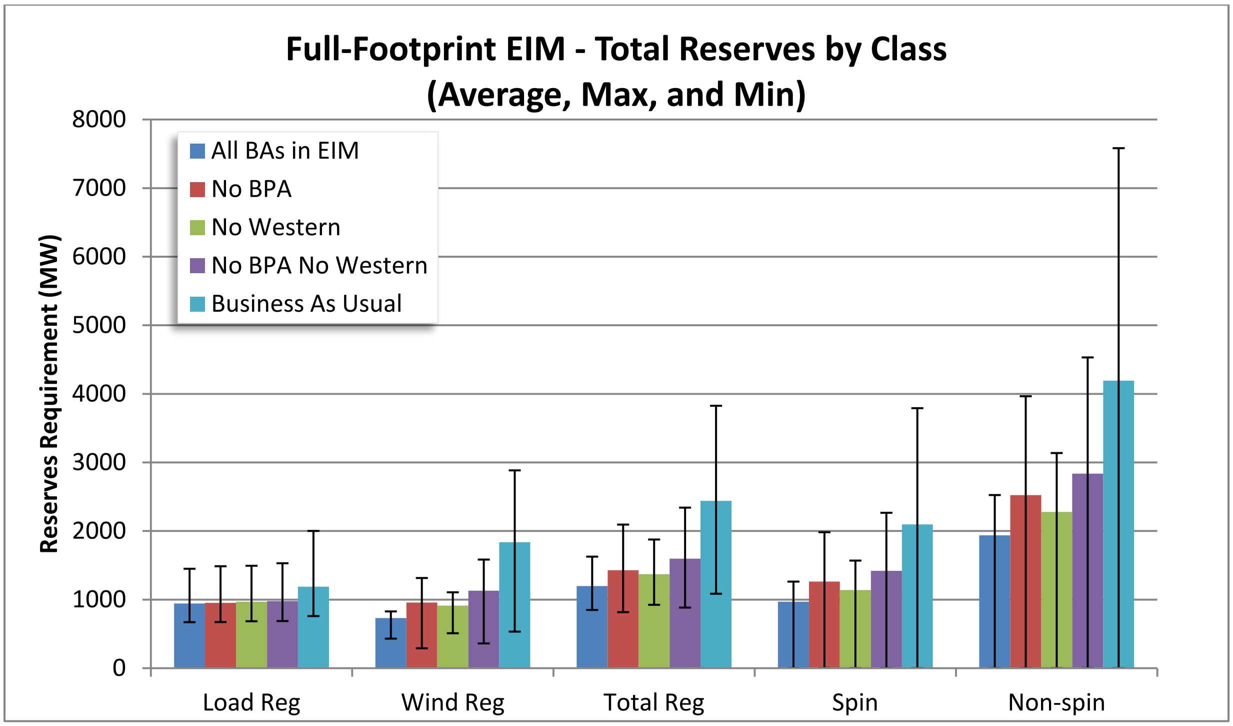


Figure 74. Reserve requirements comparison with and without optional participants for the footprint EIM

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.

This analysis demonstrated the additional reduction in reserves by combining load and wind into the same EIM structure, while modest compared to the gains seen from wind-only EIM, are significant. This is because load aggregation results in lower return. This lower return is, as discussed earlier, due to the higher correlation of load across an EIM footprint compared to wind. The majority of the difference seen when wind and load are combined is due to the fact that the load and wind regulation components are not perfectly correlated, so they do not add linearly. Instead, wind and load regulation components must be added statistically when balanced in the same EIM.

Figure 75 shows a summary of the 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 combined wind and load 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 is 1,198 MW while the requirement for the separate case is 1,672 MW. Also comparing combined regional EIM to regional load/regional wind implantation we see that the total reserves are 2,087 MW for the separate EIMs compared to 1,547 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.

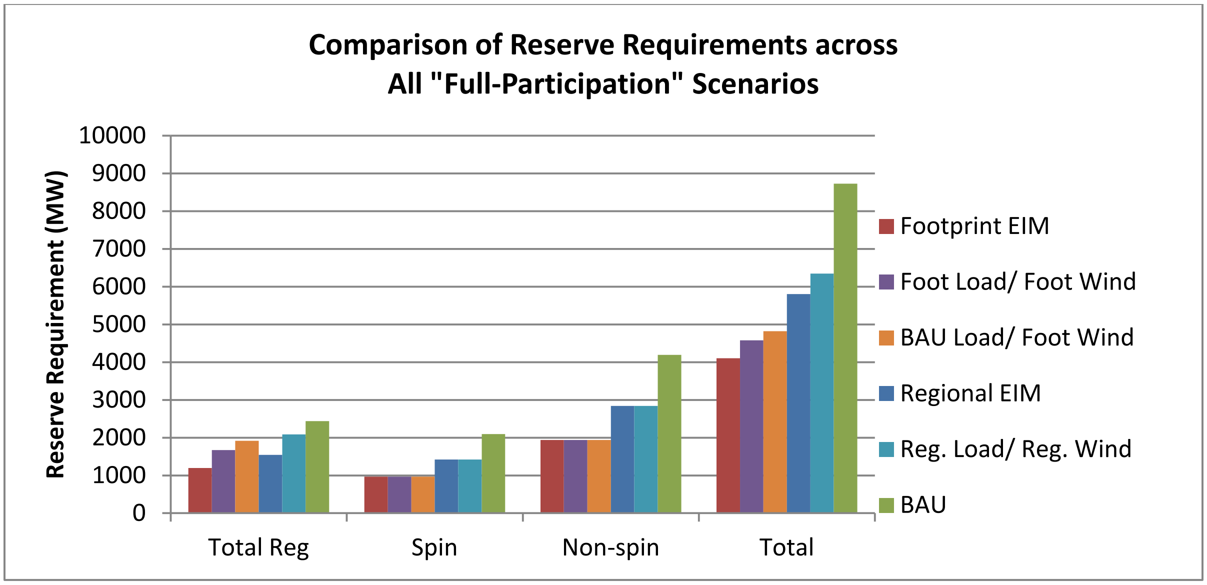


Figure 75. Reserve requirements across all "full-participation" scenarios

5.8 Effects Alternative Scheduling

Both faster scheduling (economic dispatch) and aggregation over a larger area reduce the regulation reserve requirements, as shown in Figure 76. Ten-minute scheduling requires about 29% of the regulation reserves compared to hourly scheduling under all aggregations. Five-minute scheduling will require even less. Similarly, when all 29 BAs cooperate (All) they need less than half (49% for 10-minute scheduling) of the total regulation compared to the BAU case, *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.*

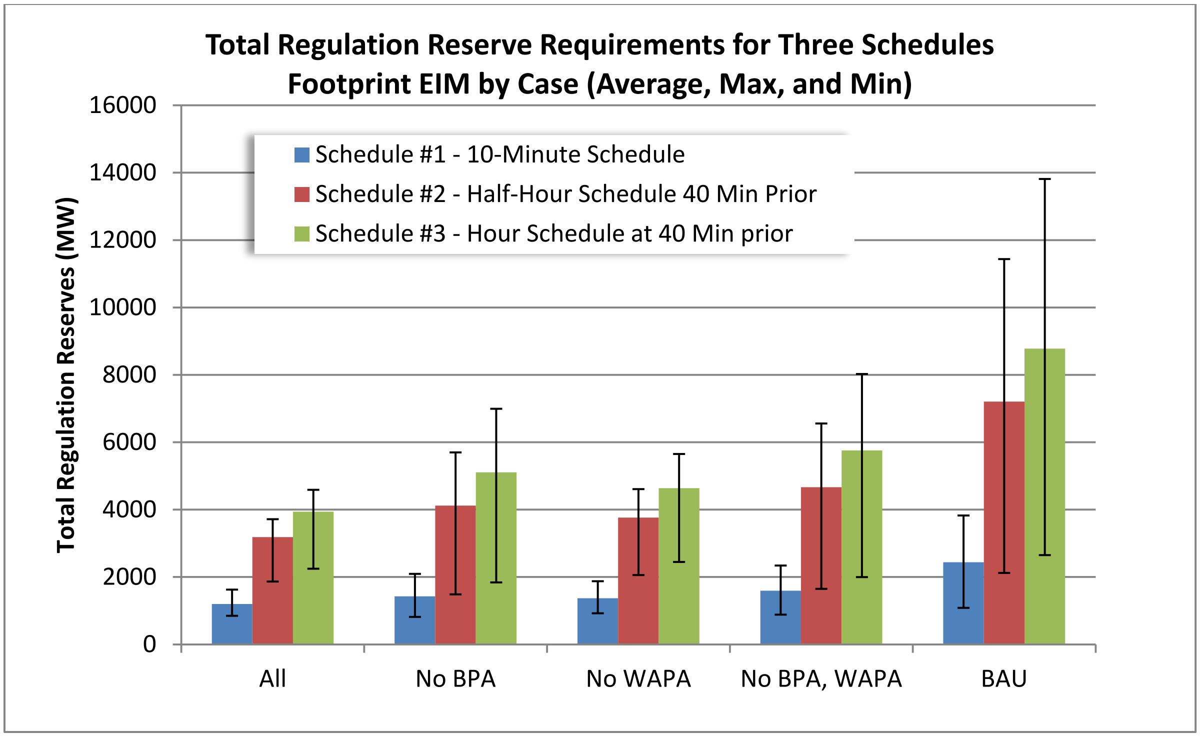
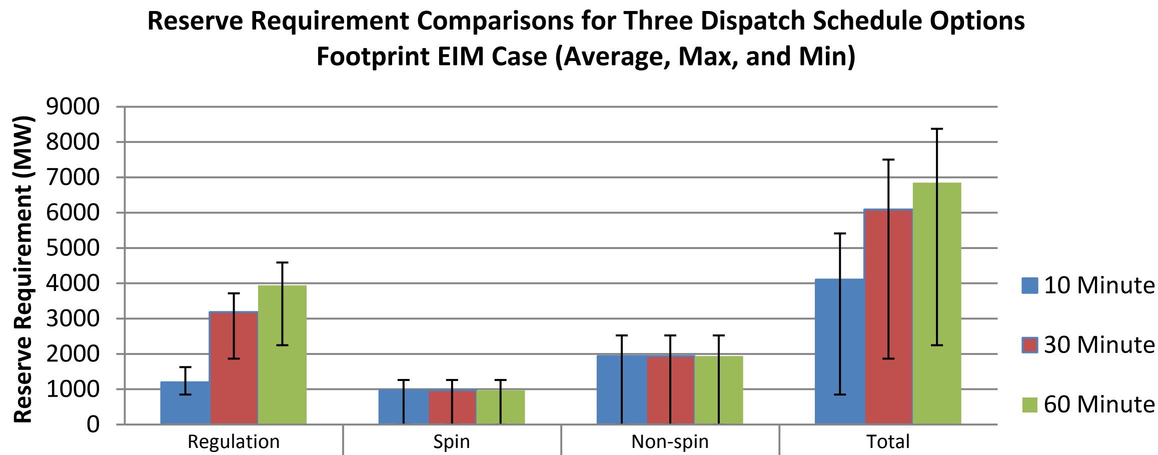


Figure 76. Faster scheduling and larger aggregation greatly reduce the total required regulating reserves

Figure 77 shows the results for three dispatch and forecast lead time sets based on 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 clear. The average total regulation requirement is reduced from 3,942 MW for a 60-minute dispatch to 1,198 MW for the 10-minute dispatch. This represents a savings of 70% on regulation needs and 40% on total reserves (right most columns). All of these savings are from wind-related regulation requirements only. In reality, 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 only on hour-ahead forecast errors.



	Regulation	Spin	Non-spin	Total
10 Minute	1198	969	1938	4105
30 Minute	3184	969	1938	6091
60 Minute	3942	969	1938	6849

Figure 77. Effect of forecast lead time and dispatch schedule on reserve requirements

To further illustrate the effect of dispatch interval and forecast lead time, we ran additional cases for the footprint and regional cooperation. Figure 78 and Table 13 show these results.

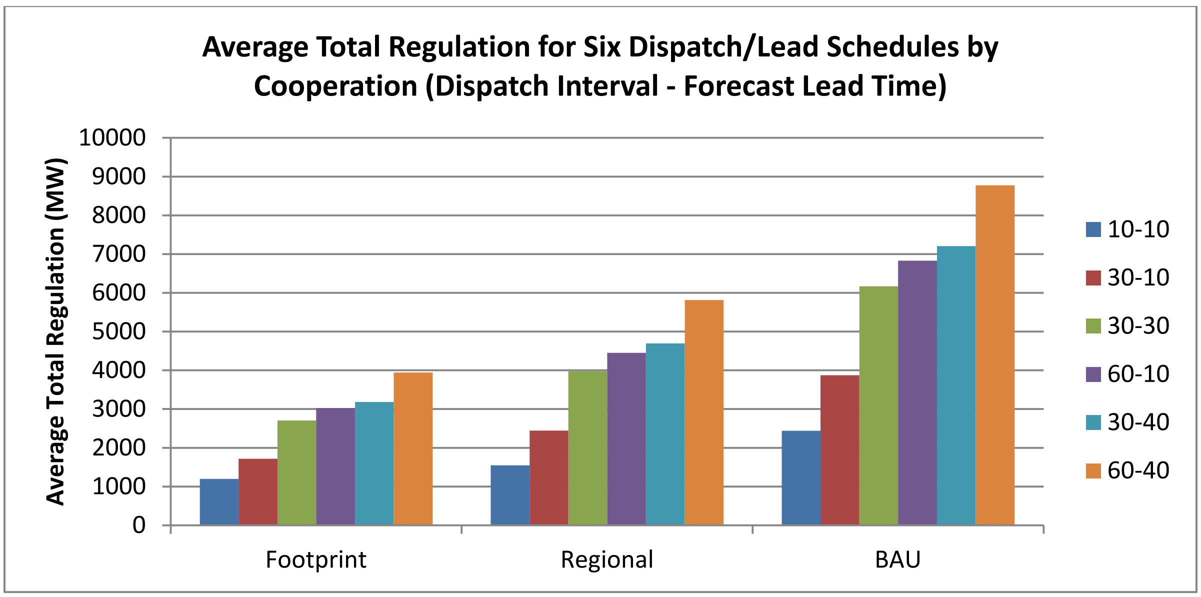


Figure 78. Comparison of regulation requirements with various cooperation regimes and dispatch/forecast lead times

One interesting aspect is the relative reduction in reserves regardless of the dispatch schedule. For a given cooperation regime (footprint or regional), the reduction in reserves is nearly the same for each of the dispatch/forecast lead times analyzed. A BA can capture the sub-hourly scheduling benefit even without coordination with neighboring BAs.

Table 13. Average Total Regulation Requirements Are a Constant Percentage of BAU Relative to Various Dispatch/Lead Time Schedules

Dispatch-Forecast Lead (Min)	Avg. Regulation (MW)			Compared to BAU		
	Footprint	Regional	BAU	Footprint	Regional	BAU
10-10	1,198	1,547	2,440	49%	63%	100%
30-10	1,718	2,444	3,873	44%	63%	100%
30-30	2,705	3,975	6,168	44%	64%	100%
60-10	3,027	4,453	6,831	44%	65%	100%
30-40	3,184	4,696	7,205	44%	65%	100%
60-40	3,942	5,813	8,777	45%	66%	100%

6 Conclusions

This report examines alternative implementations of the proposed EIM in the non-market areas of the WI. 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.

The proposed EIM includes two independent beneficial changes in current operating practices: sub-hourly scheduling and inter-BA coordination. Half of the load in the country lies 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. Inter-BA cooperation has been practiced for decades with contingency reserve sharing pools and energy transactions. The EIM simply extends this concept through an automated imbalance market.

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 Western), and the wind-only BAAs we analyzed will still improve on the BAU case 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 excluded 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 cost-benefit analysis to determine whether it may be economically efficient to implement institutional changes that can help move toward a full EIM implementation. 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 over time, participants may conclude that some form of coordinate commitment will achieve additional savings, although 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 tomorrow through the EIM and incorporate those expectations in their own unit commitment. Participants may engage in bilateral contracts to add certainty to those expectations. Firm transmission may be necessary to fully capture the benefits of coordinated unit commitment.

7 References

[1] GE Energy. (2010). "Western Wind and Solar Integration Study." 536 pp.; NREL Report No. SR-550-47434. Available at http://www.nrel.gov/docs/fy10osti/47434.pdf.

[2] Milligan, M.; Kirby, B. (2007). Impact of Balancing Areas Size, Obligation Sharing, and Ramping Capability on Wind Integration: Preprint. 43 pp.; NREL Report No. CP-500-41809. Available at http://www.nrel.gov/docs/fy07osti/41809.pdf.

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[6] B. Kirby, 2006, Demand Response For Power System Reliability: FAQ, ORNL/TM 2006/565, Oak Ridge National Laboratory, December.

[7] NERC (2008). "NERC Balancing Authority (BA) Certification of Naturener Glacier Wind Energy 1 (GWA) Operated by Constellation Energy Control and Dispatch (CECD)." http://www.nerc.com/files/NaturEner%20Final%20Report.pdf.

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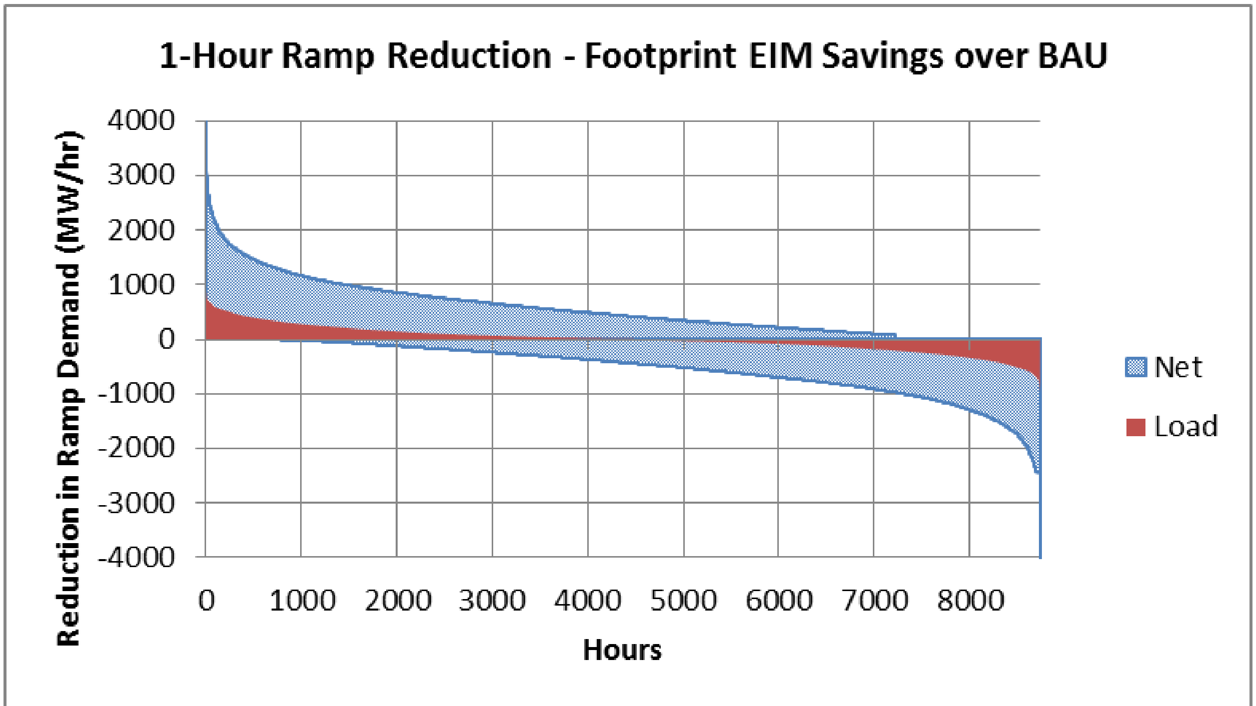
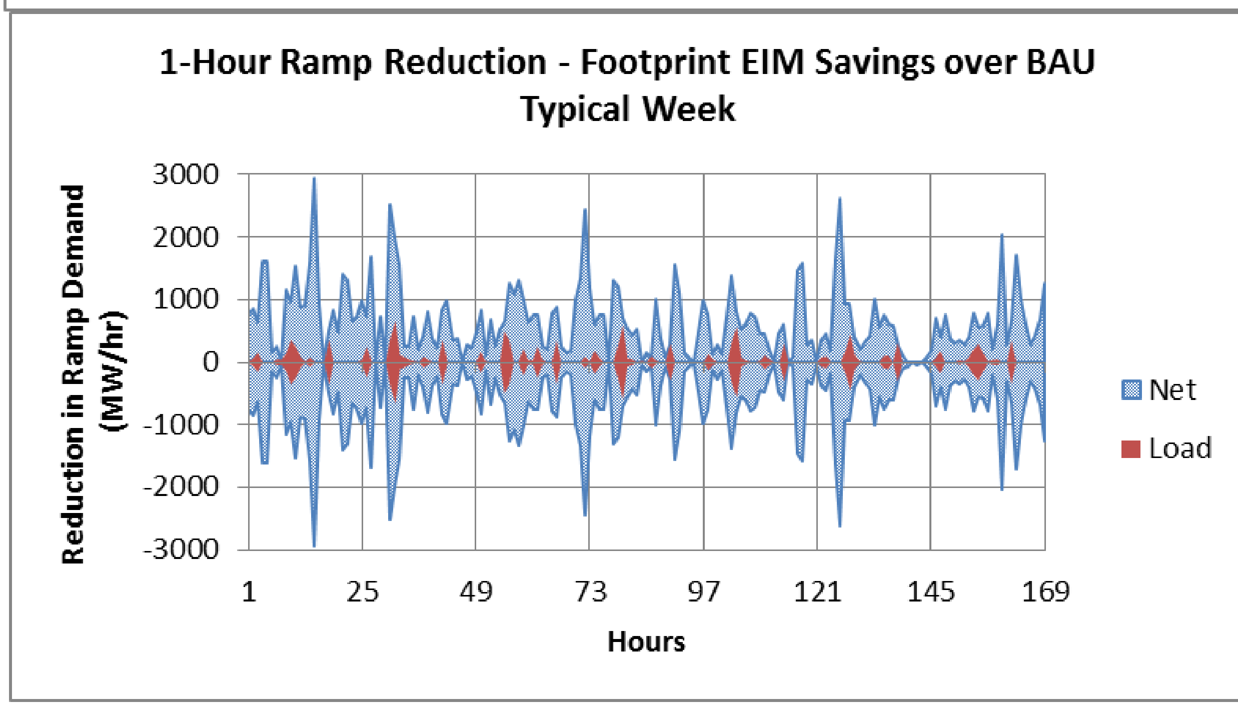
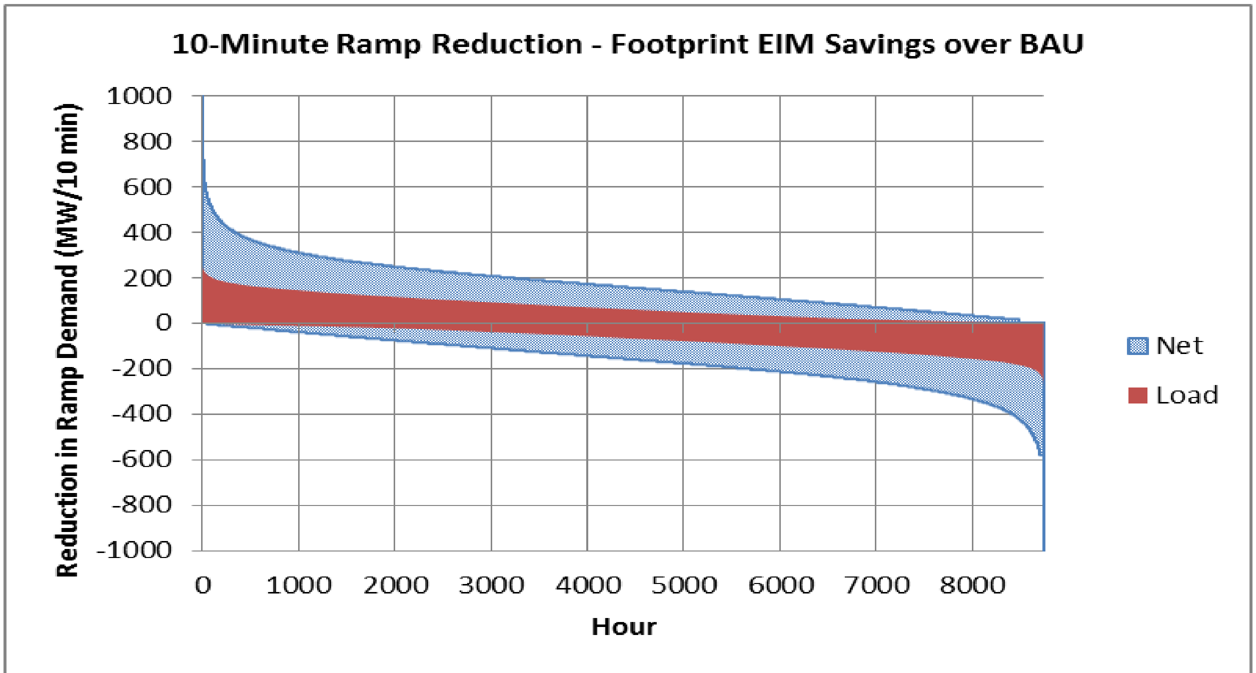
Appendix A. Ramp Savings Plots

This appendix contains ramp reduction plots for all cases we ran as part of this study. The case conditions for each plot are described in the plot title. There are four plots for each case. The first two plots show 1-hour ramp savings and the second pair shows 10-minute ramp savings.






10-Minute Ramp Reduction - Footprint EIM Savings over BAU
Reduction in Ramp Demand (MW/10 min)
1000
800
600
400
200
0
-200
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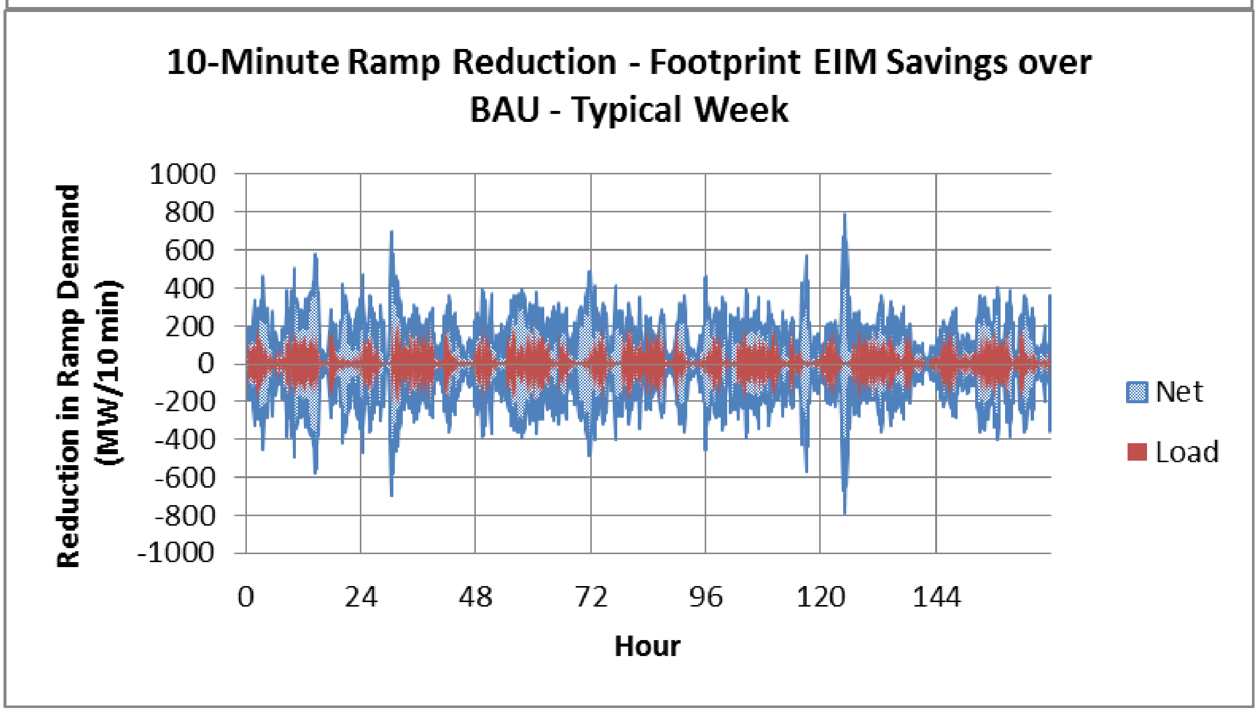
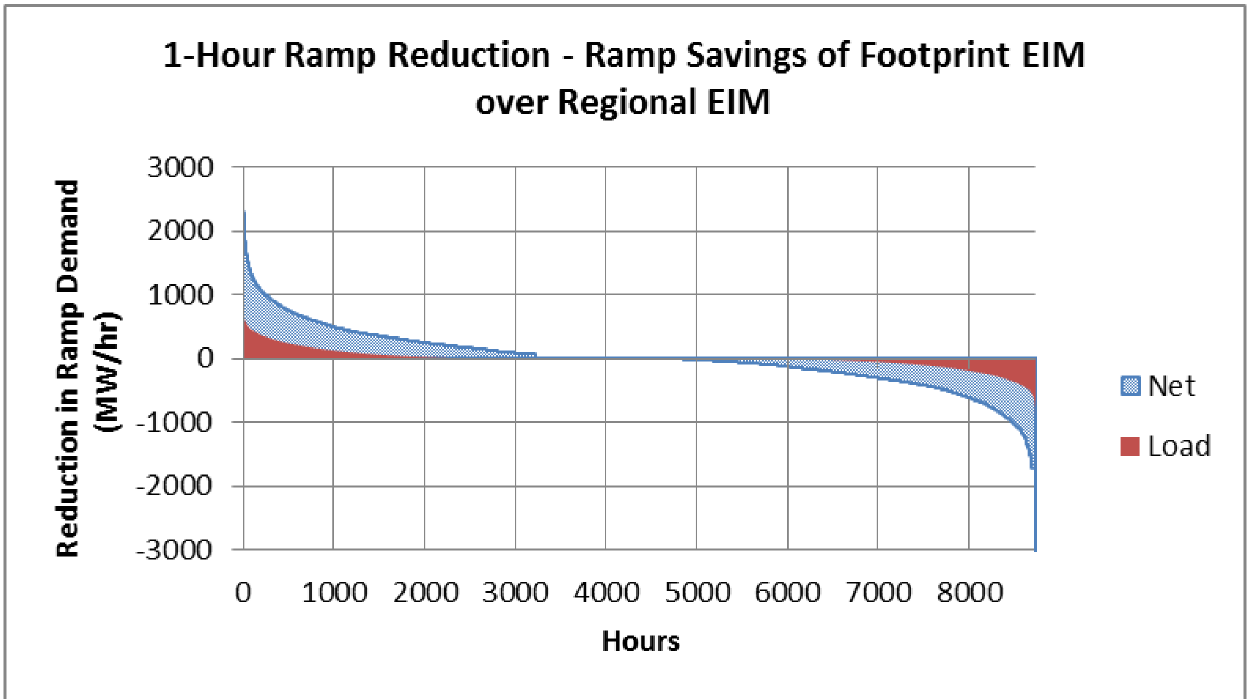
0
1000
2000
3000
4000
5000
6000
7000
8000
Hour
Net
Load


10-Minute Ramp Reduction - Footprint EIM Savings over BAU - Typical Week
Reduction in Ramp Demand (MW/10 min)
1000
800
600
400
200
0
-200
-400
-600
-800
-1000
0
24
48
72
96
120
144
Hour
Net
Load


1-Hour Ramp Reduction - Ramp Savings of Footprint EIM over Regional EIM
Reduction in Ramp Demand (MW/hr)
3000
2000
1000
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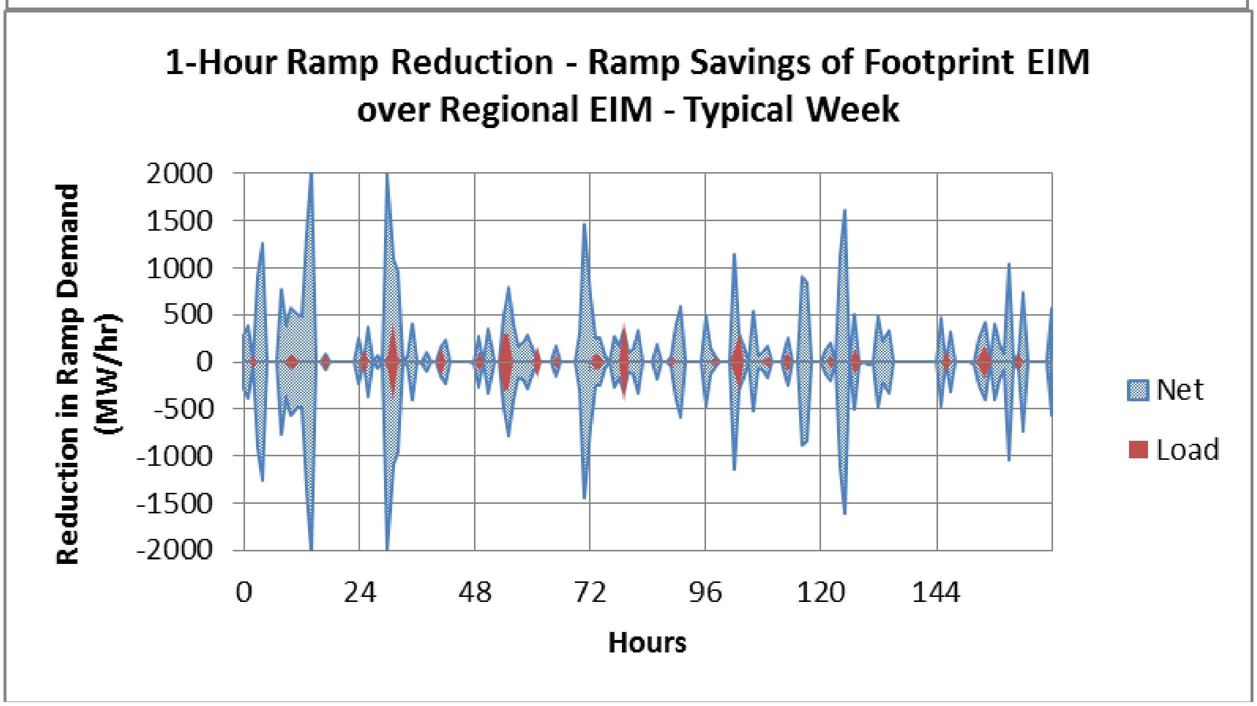
-1000
-2000
-3000
0
1000
2000
3000
4000
5000
6000
7000
8000
Hours
Net
Load


1-Hour Ramp Reduction - Ramp Savings of Footprint EIM over Regional EIM - Typical Week
Reduction in Ramp Demand (MW/hr)
2000
1500
1000
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-500
-1000
-1500
-2000
0
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48
72
96
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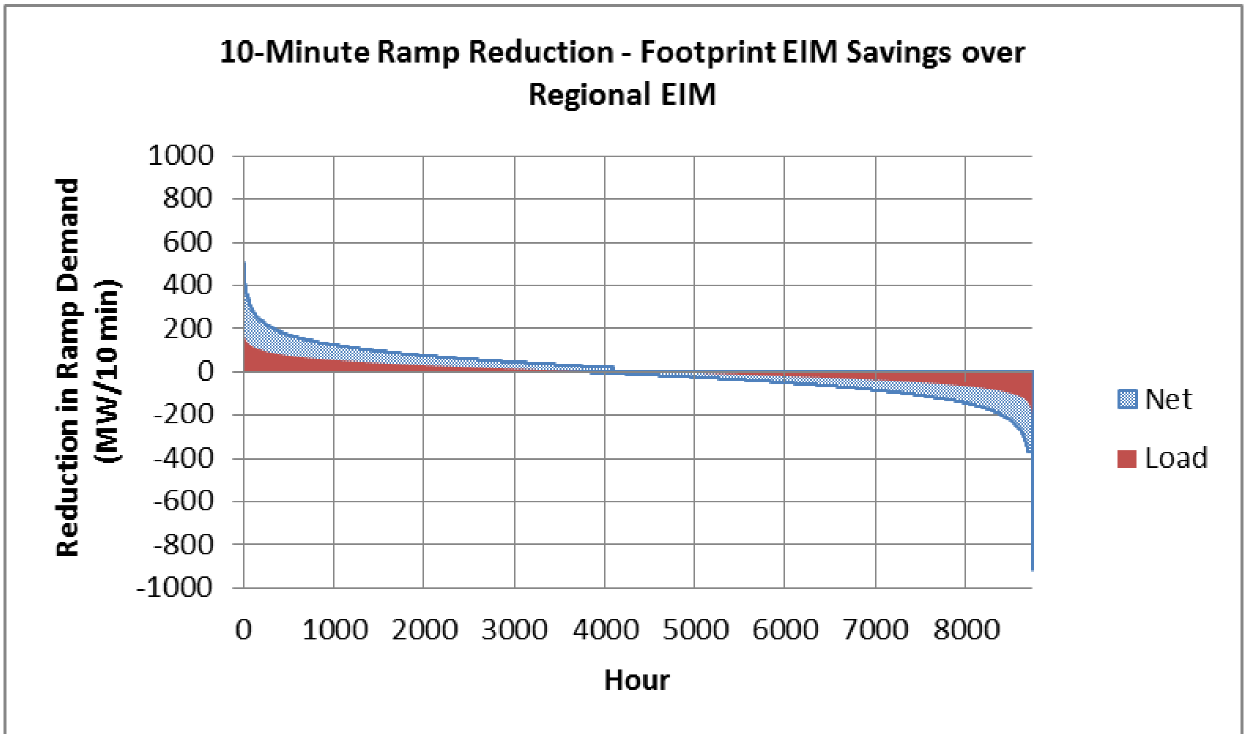
10-Minute Ramp Reduction - Footprint EIM Savings over Regional EIM
Reduction in Ramp Demand (MW/10 min)
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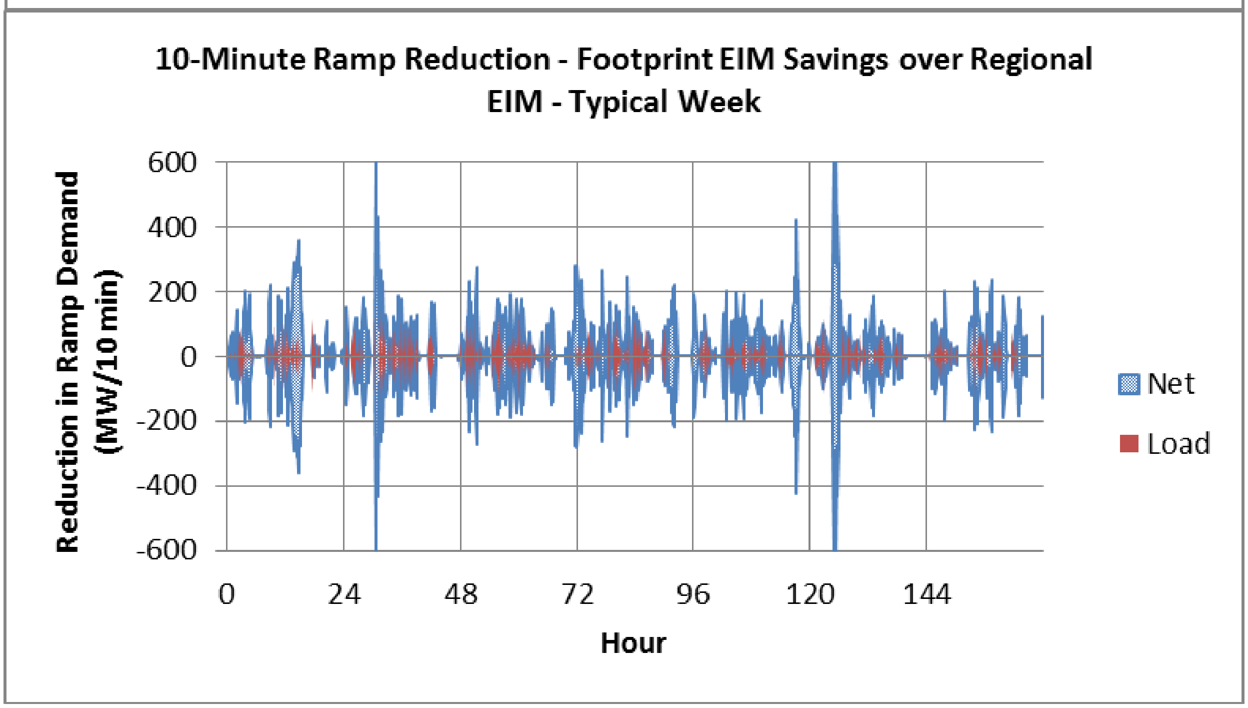
10-Minute Ramp Reduction - Footprint EIM Savings over Regional EIM - Typical Week
Reduction in Ramp Demand (MW/10 min)
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-600
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48
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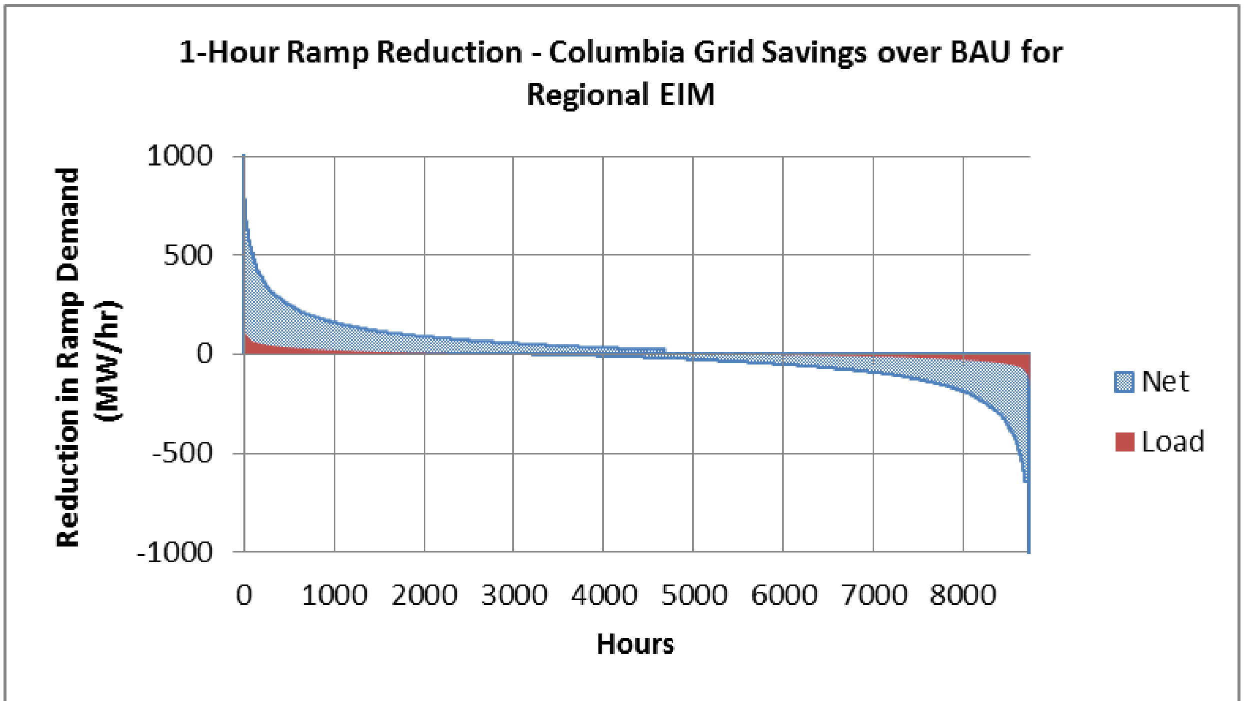
1-Hour Ramp Reduction - Columbia Grid Savings over BAU for Regional EIM
Reduction in Ramp Demand (MW/hr)
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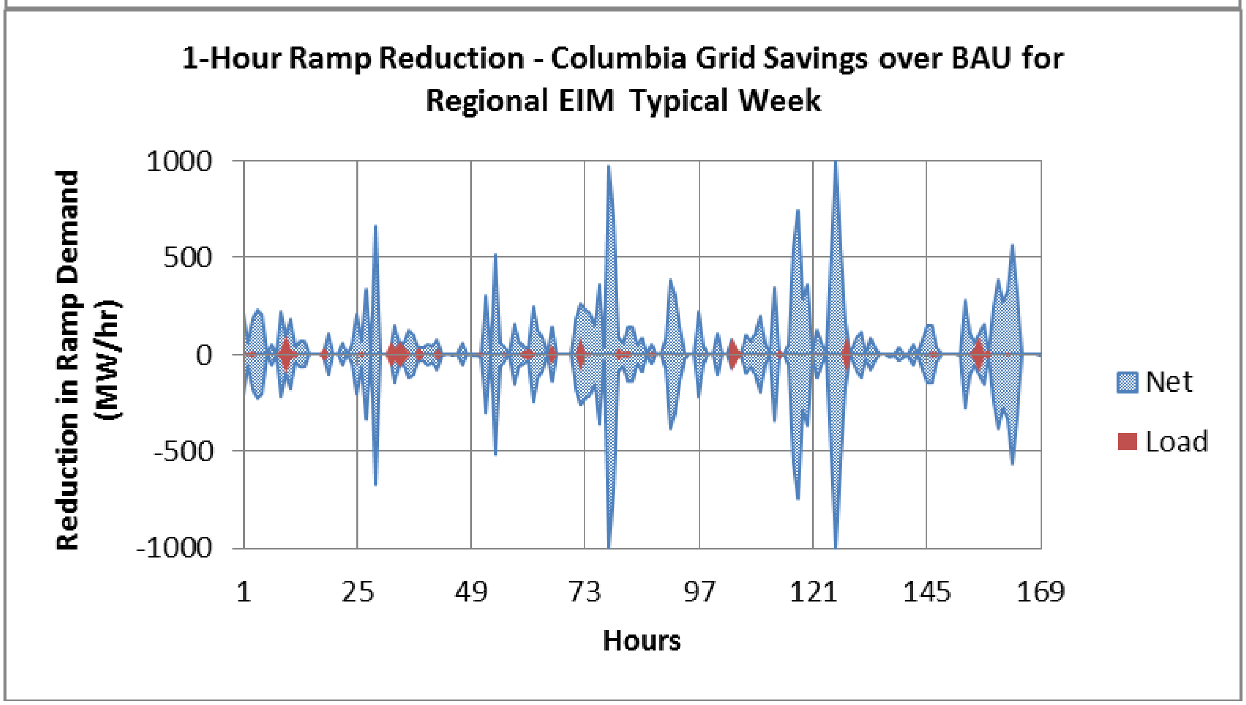
1-Hour Ramp Reduction - Columbia Grid Savings over BAU for Regional EIM Typical Week
Reduction in Ramp Demand (MW/hr)
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73
97
121
145
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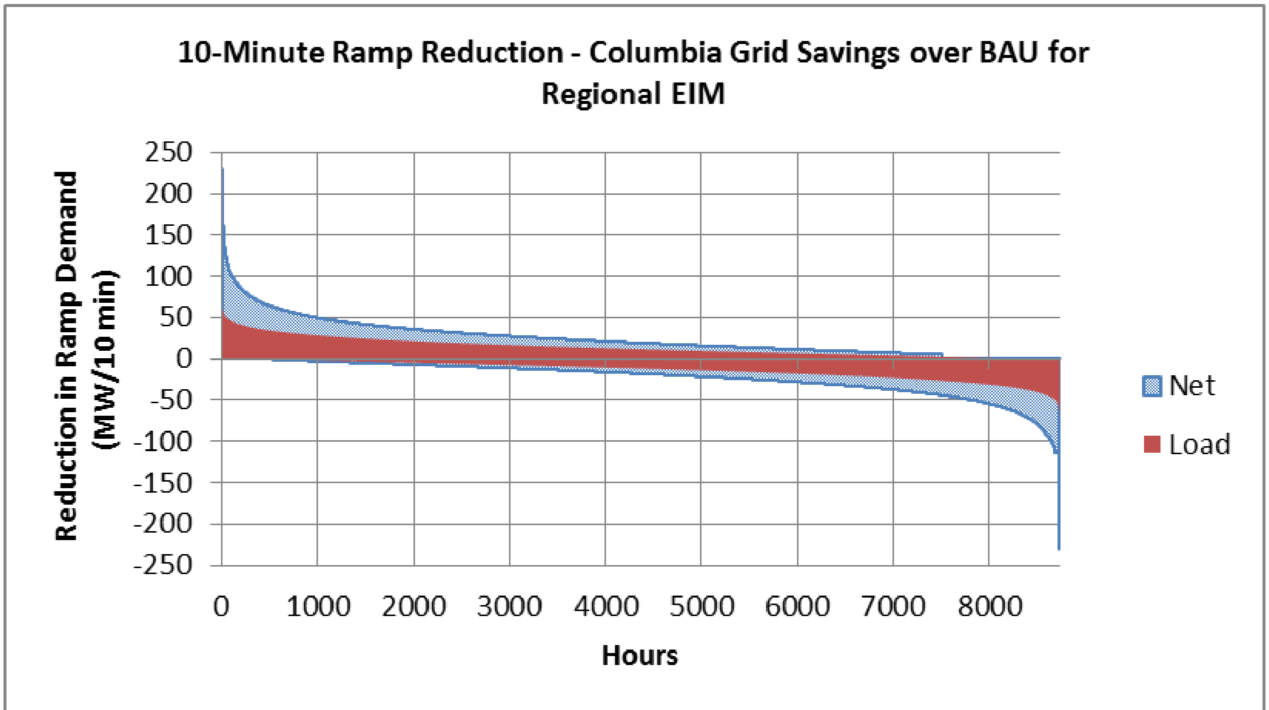
10-Minute Ramp Reduction - Columbia Grid Savings over BAU for Regional EIM
Reduction in Ramp Demand (MW/10 min)
250
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-200
-250
0
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3000
4000
5000
6000
7000
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Hours
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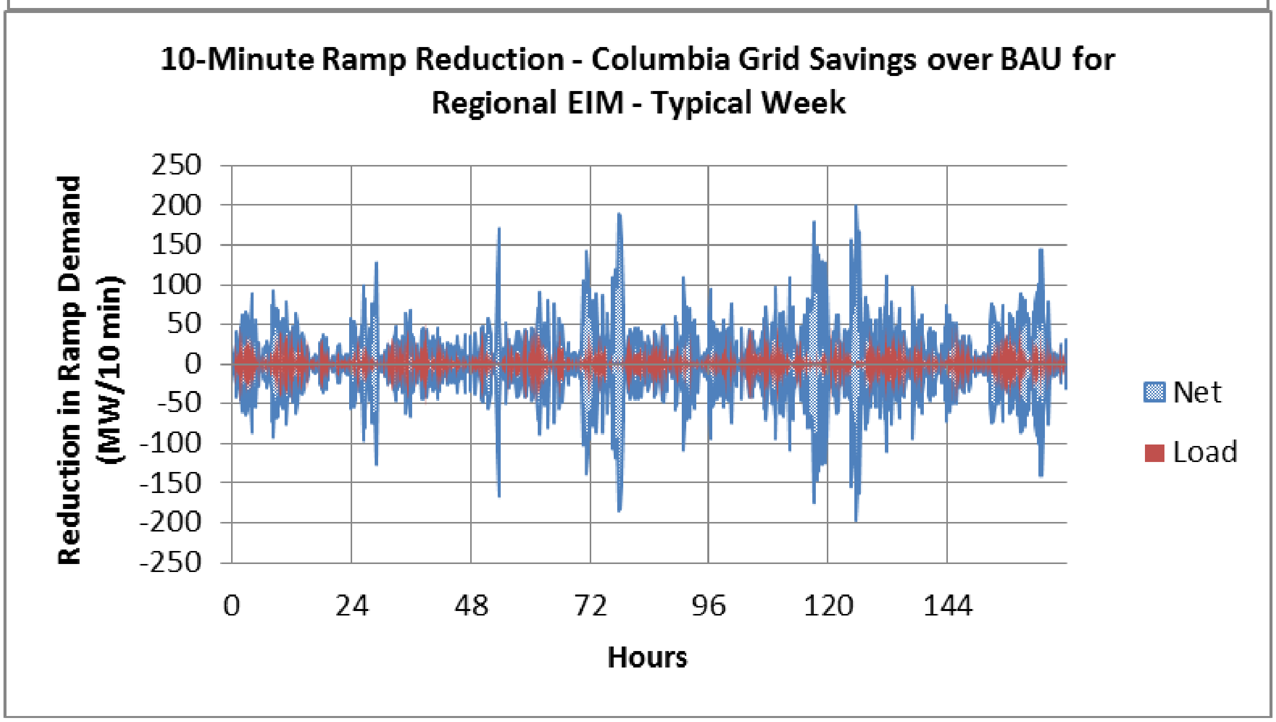
10-Minute Ramp Reduction - Columbia Grid Savings over BAU for Regional EIM - Typical Week
Reduction in Ramp Demand (MW/10 min)
250
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-50
-100
-150
-200
-250
0
24
48
72
96
120
144
Hours
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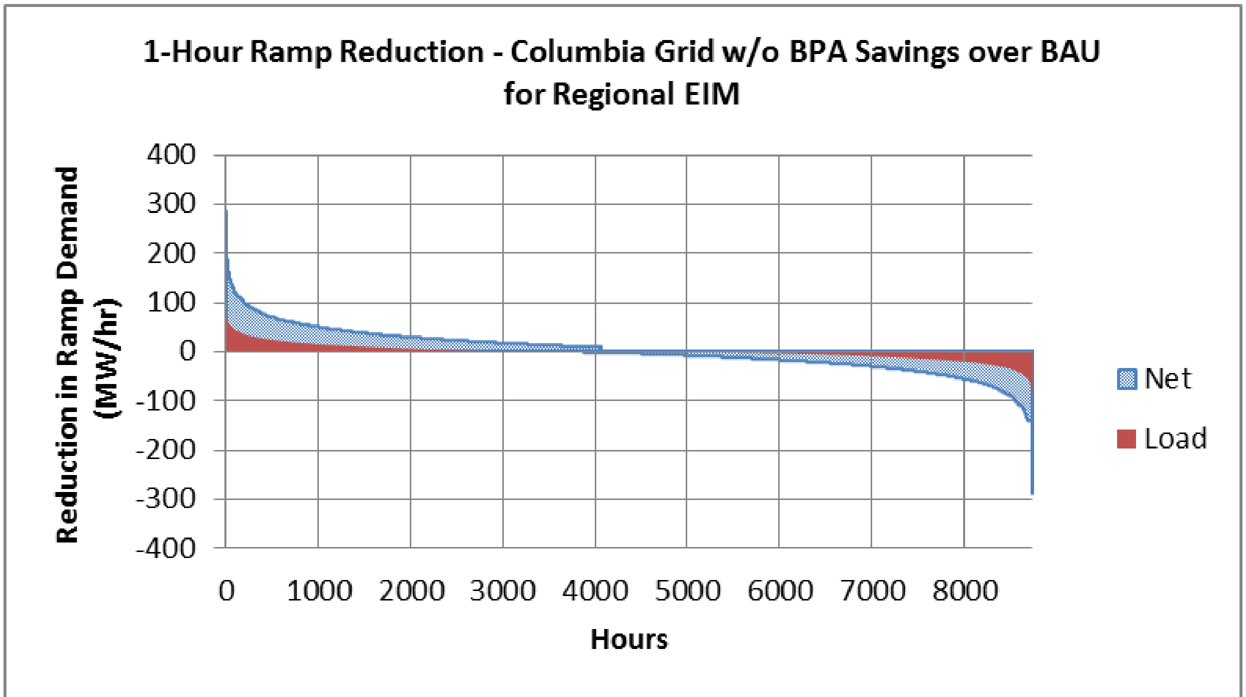
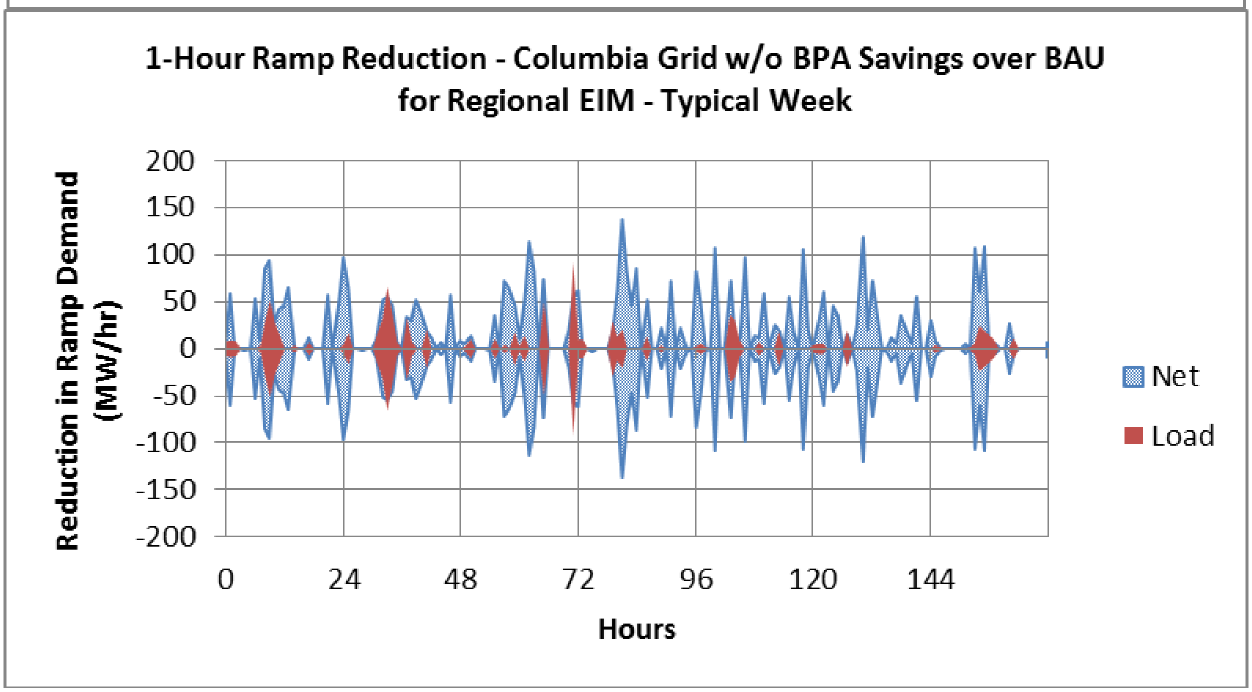
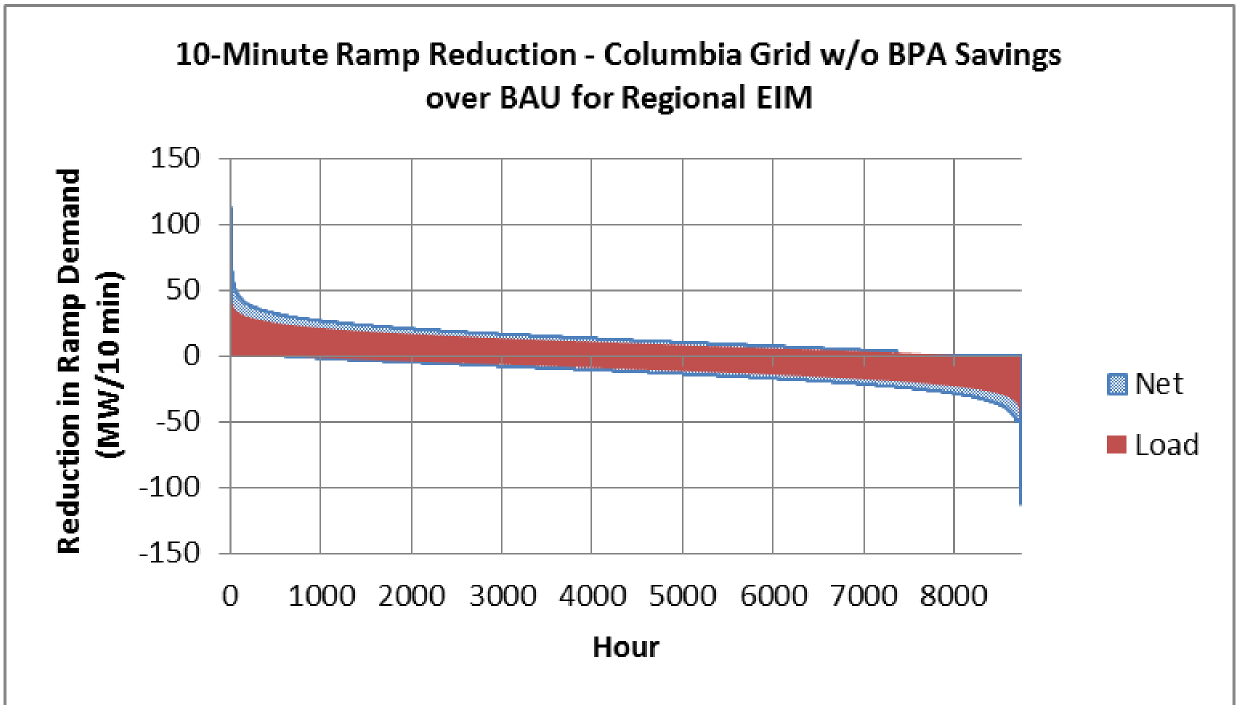
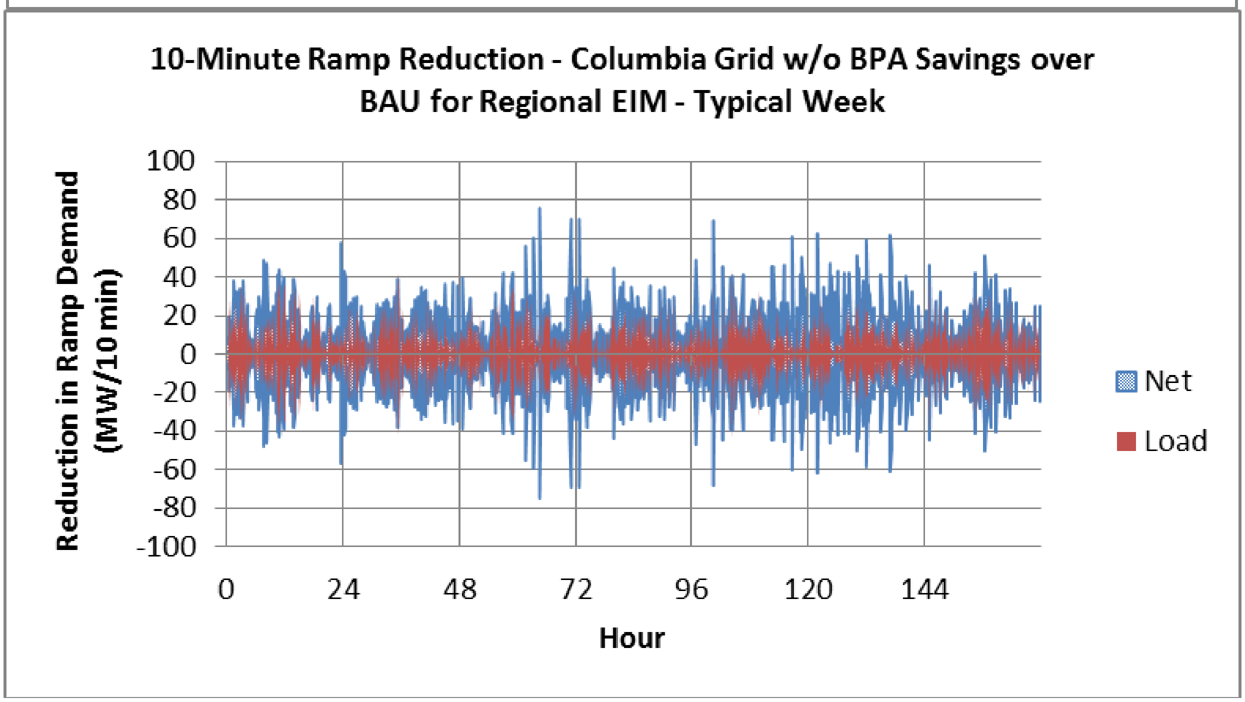
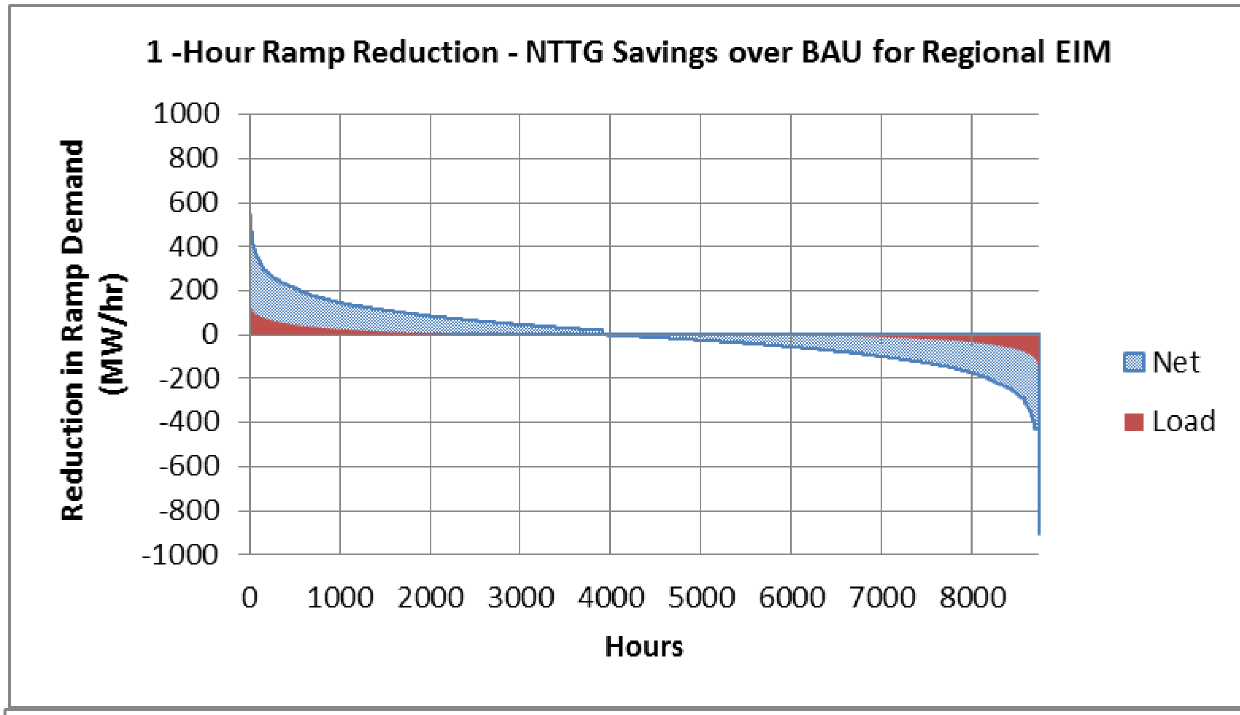
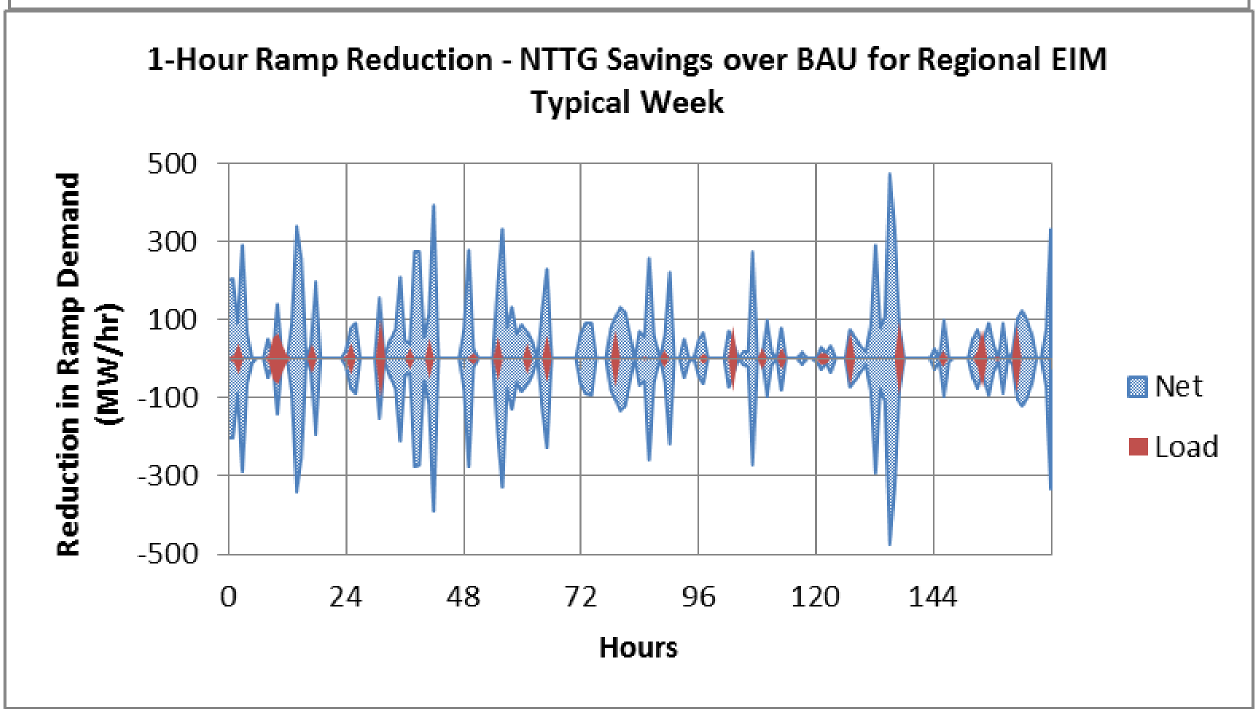

1-Hour Ramp Reduction - Columbia Grid w/o BPA Savings over BAU for Regional EIM
Reduction in Ramp Demand (MW/hr)
400
300
200
100
0
-100
-200
-300
-400
0
1000
2000
3000
4000
5000
6000
7000
8000
Hours
Net
Load

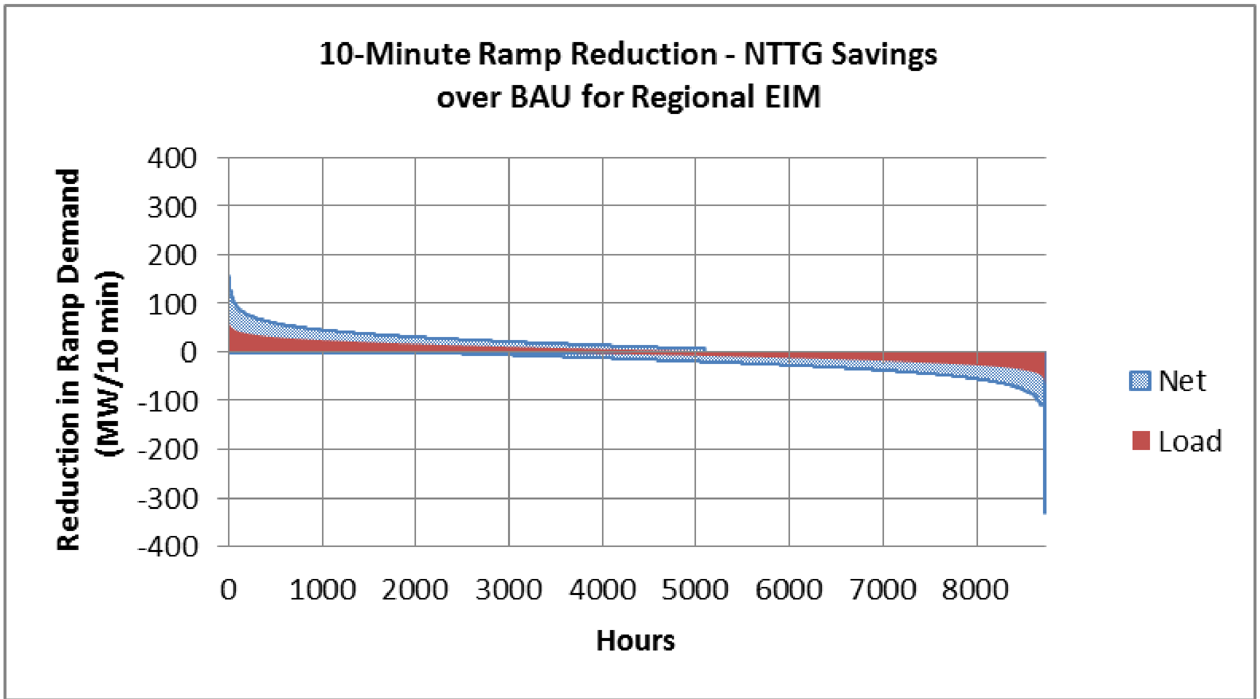

1-Hour Ramp Reduction - Columbia Grid w/o BPA Savings over BAU for Regional EIM - Typical Week
Reduction in Ramp Demand (MW/hr)
200
150
100
50
0
-50
-100
-150
-200
0
24
48
72
96
120
144
Hours
Net
Load

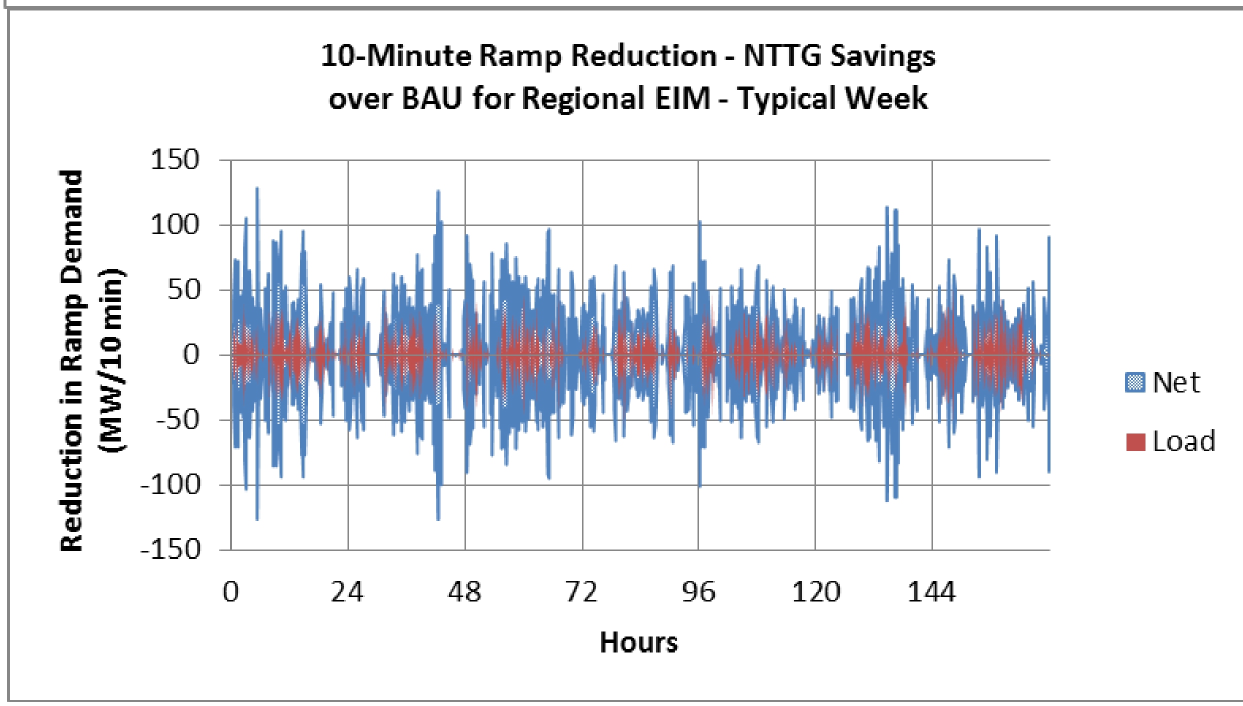

10-Minute Ramp Reduction - Columbia Grid w/o BPA Savings over BAU for Regional EIM
Reduction in Ramp Demand (MW/10 min)
150
100
50
0
-50
-100
-150
0
1000
2000
3000
4000
5000
6000
7000
8000
Hour
Net
Load

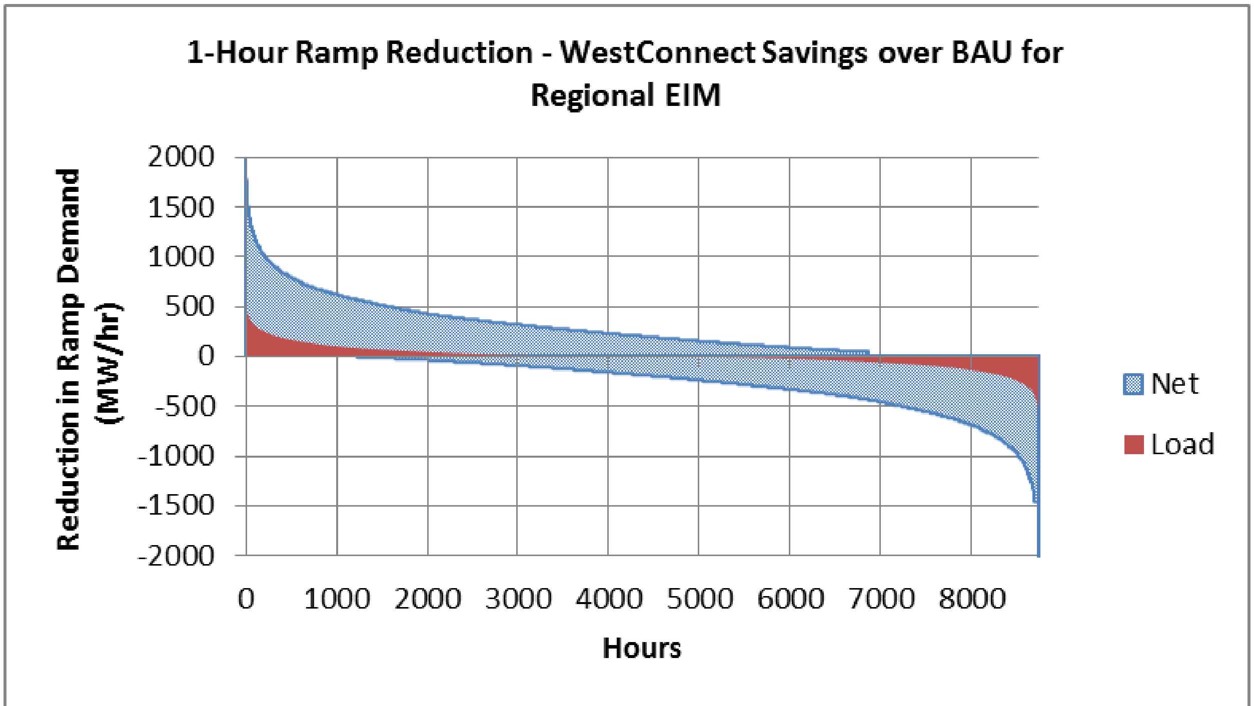

10-Minute Ramp Reduction - Columbia Grid w/o BPA Savings over BAU for Regional EIM - Typical Week
Reduction in Ramp Demand (MW/10 min)
100
80
60
40
20
0
-20
-40
-60
-80
-100
0
24
48
72
96
120
144
Hour
Net
Load

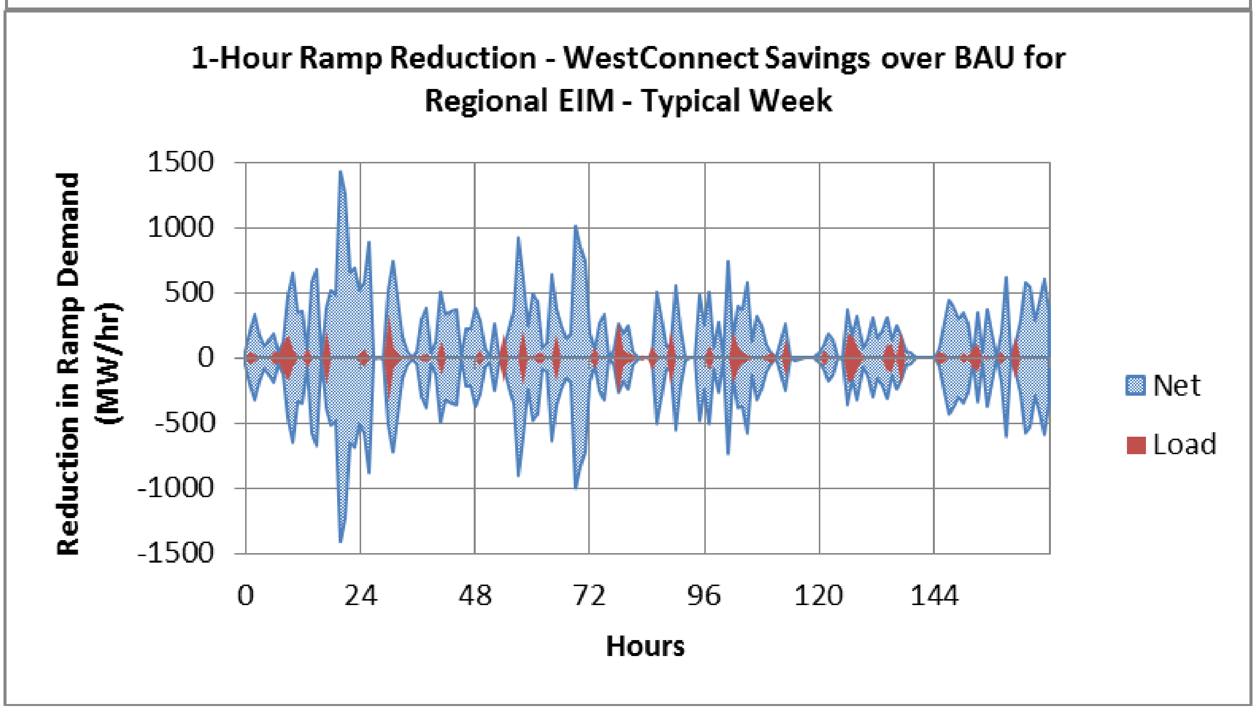

1 -Hour Ramp Reduction - NTTG Savings over BAU for Regional EIM
Reduction in Ramp Demand (MW/hr)
1000
800
600
400
200
0
-200
-400
-600
-800
-1000
0
1000
2000
3000
4000
5000
6000
7000
8000
Hours
Net
Load

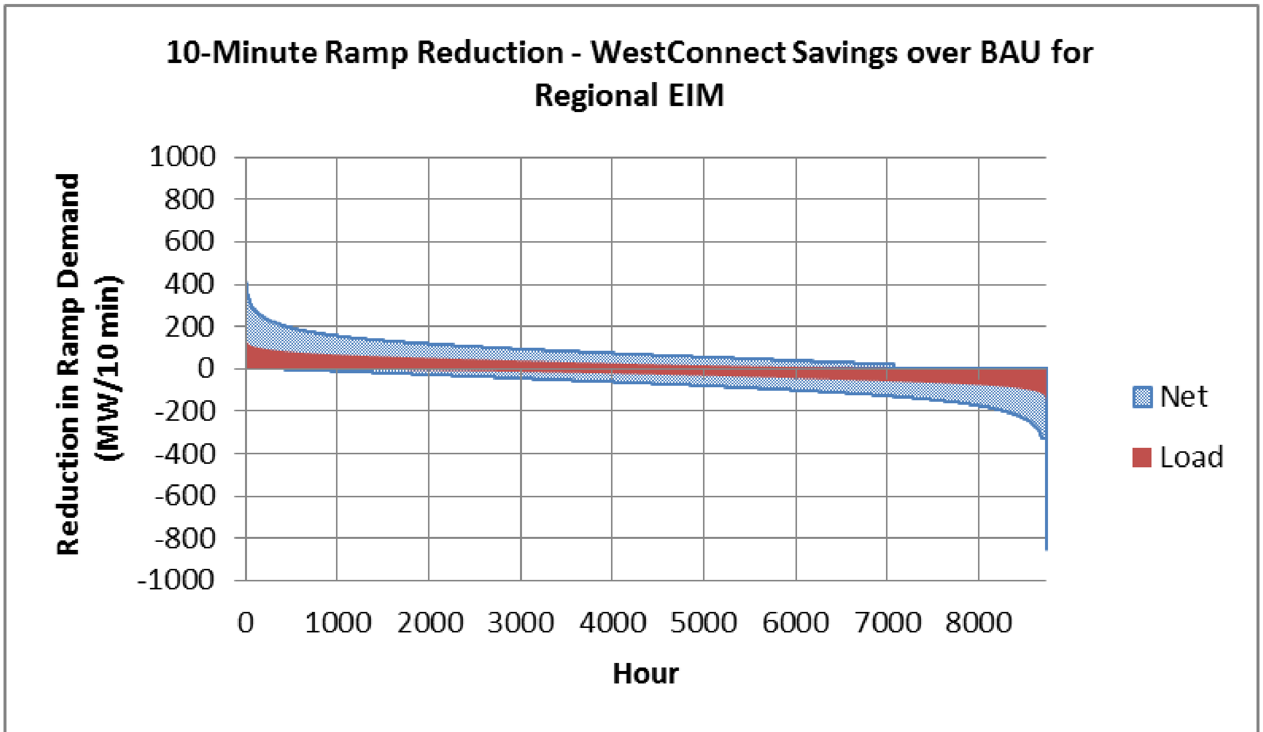

1-Hour Ramp Reduction - NTTG Savings over BAU for Regional EIM
Typical Week
Reduction in Ramp Demand (MW/hr)
500
300
100
-100
-300
-500
0
24
48
72
96
120
144
Hours
Net
Load

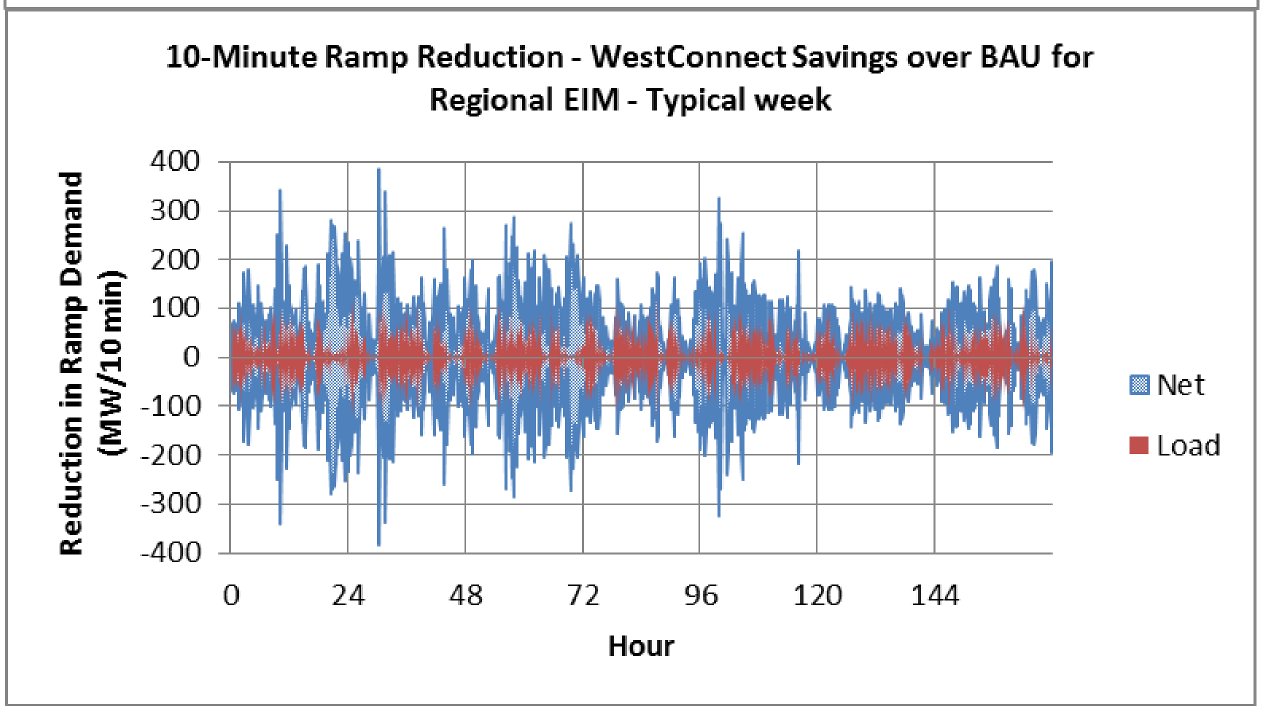

10-Minute Ramp Reduction - NTTG Savings over BAU for Regional EIM
Reduction in Ramp Demand (MW/10 min)
400
300
200
100
0
-100
-200
-300
-400
0
1000
2000
3000
4000
5000
6000
7000
8000
Hours
Net
Load

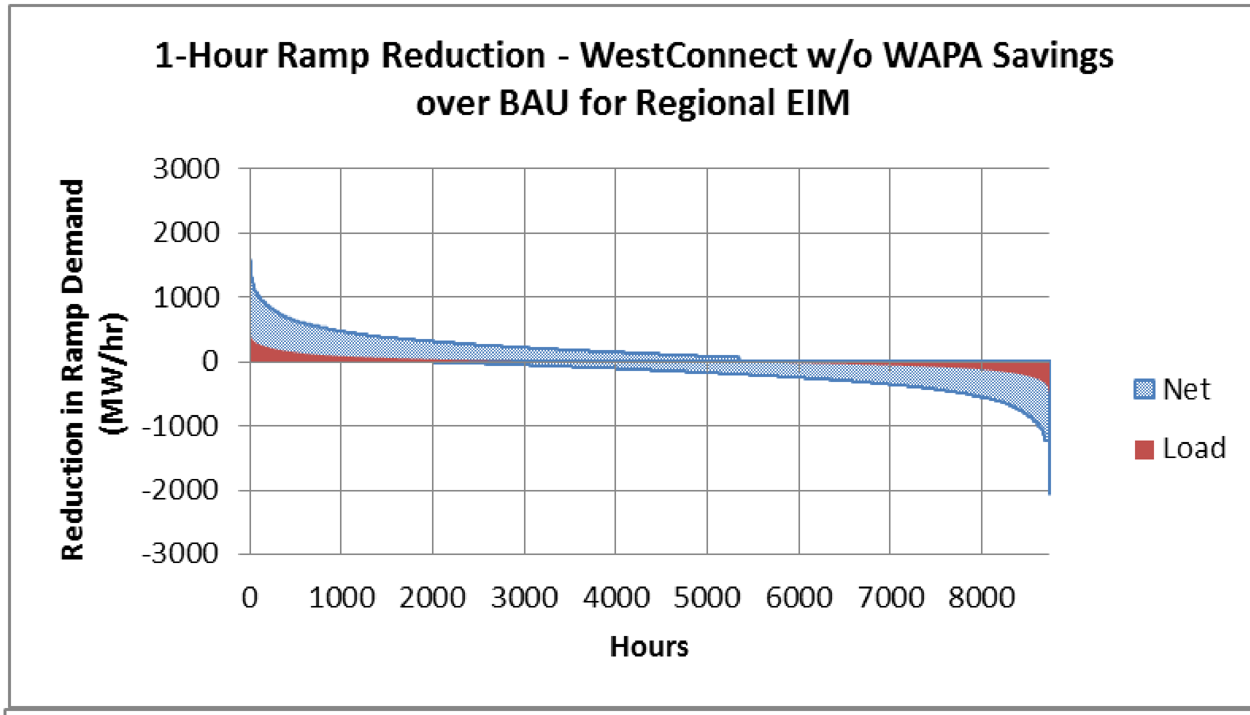

10-Minute Ramp Reduction - NTTG Savings over BAU for Regional EIM - Typical Week
Reduction in Ramp Demand (MW/10 min)
150
100
50
0
-50
-100
-150
0
24
48
72
96
120
144
Hours
Net
Load

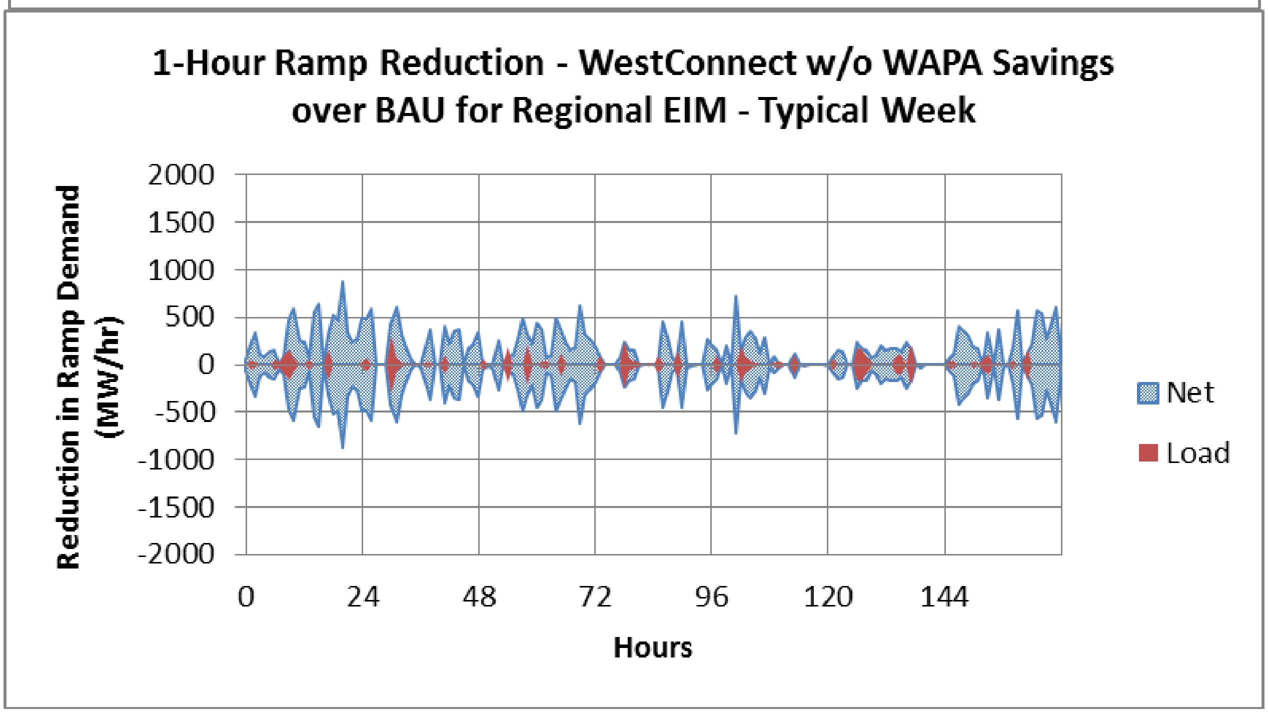

1-Hour Ramp Reduction - WestConnect Savings over BAU for Regional EIM
Reduction in Ramp Demand (MW/hr)
2000
1500
1000
500
0
-500
-1000
-1500
-2000
0
1000
2000
3000
4000
5000
6000
7000
8000
Hours
Net
Load

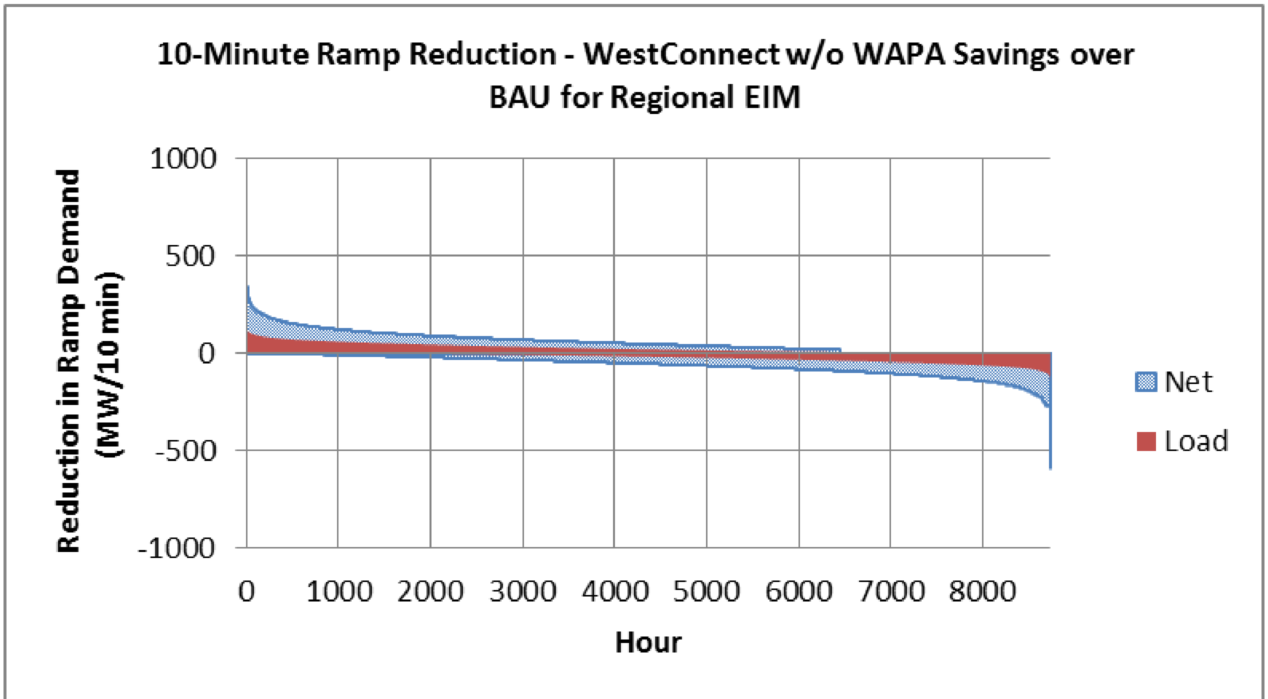

1-Hour Ramp Reduction - WestConnect Savings over BAU for Regional EIM - Typical Week
Reduction in Ramp Demand (MW/hr)
1500
1000
500
0
-500
-1000
-1500
0
24
48
72
96
120
144
Hours
Net
Load

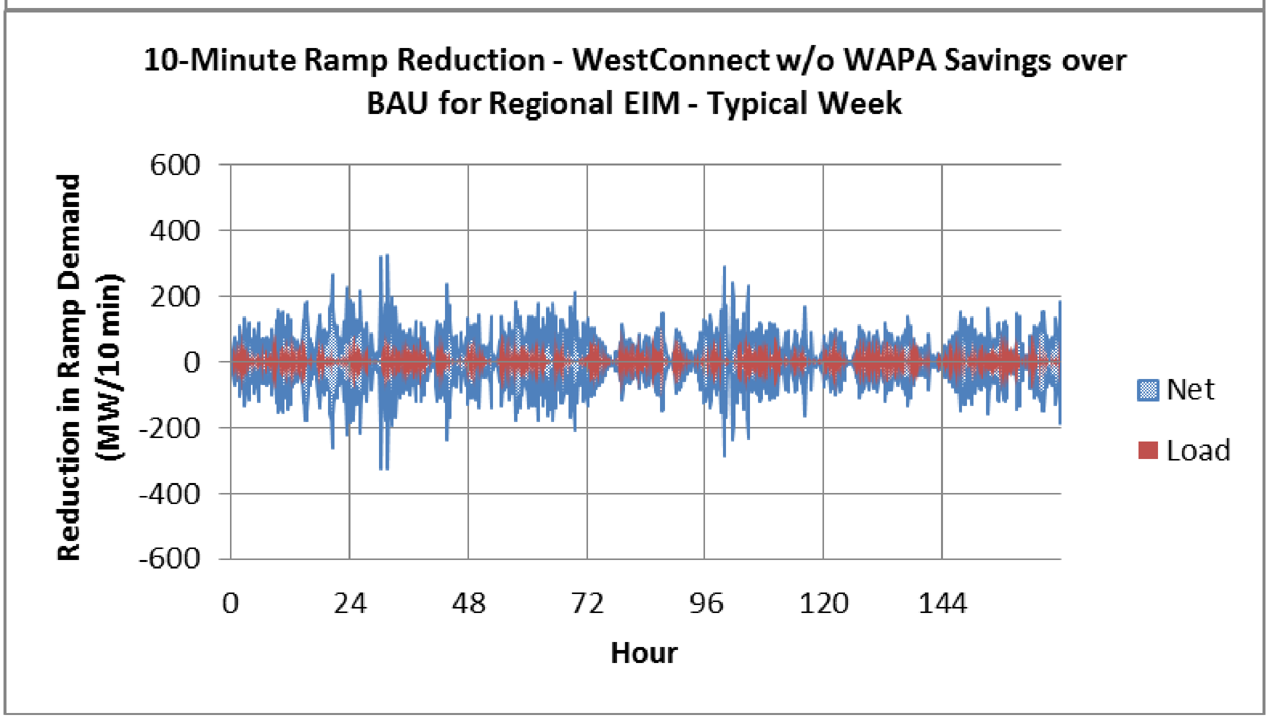

10-Minute Ramp Reduction - WestConnect Savings over BAU for Regional EIM
Reduction in Ramp Demand (MW/10 min)
1000
800
600
400
200
0
-200
-400
-600
-800
-1000
0
1000
2000
3000
4000
5000
6000
7000
8000
Hour
Net
Load


10-Minute Ramp Reduction - WestConnect Savings over BAU for Regional EIM - Typical week
Reduction in Ramp Demand (MW/10 min)
400
300
200
100
0
-100
-200
-300
-400
0
24
48
72
96
120
144
Hour
Net
Load


1-Hour Ramp Reduction - WestConnect w/o WAPA Savings over BAU for Regional EIM
Reduction in Ramp Demand (MW/hr)
3000
2000
1000
0
-1000
-2000
-3000
0
1000
2000
3000
4000
5000
6000
7000
8000
Hours
Net
Load

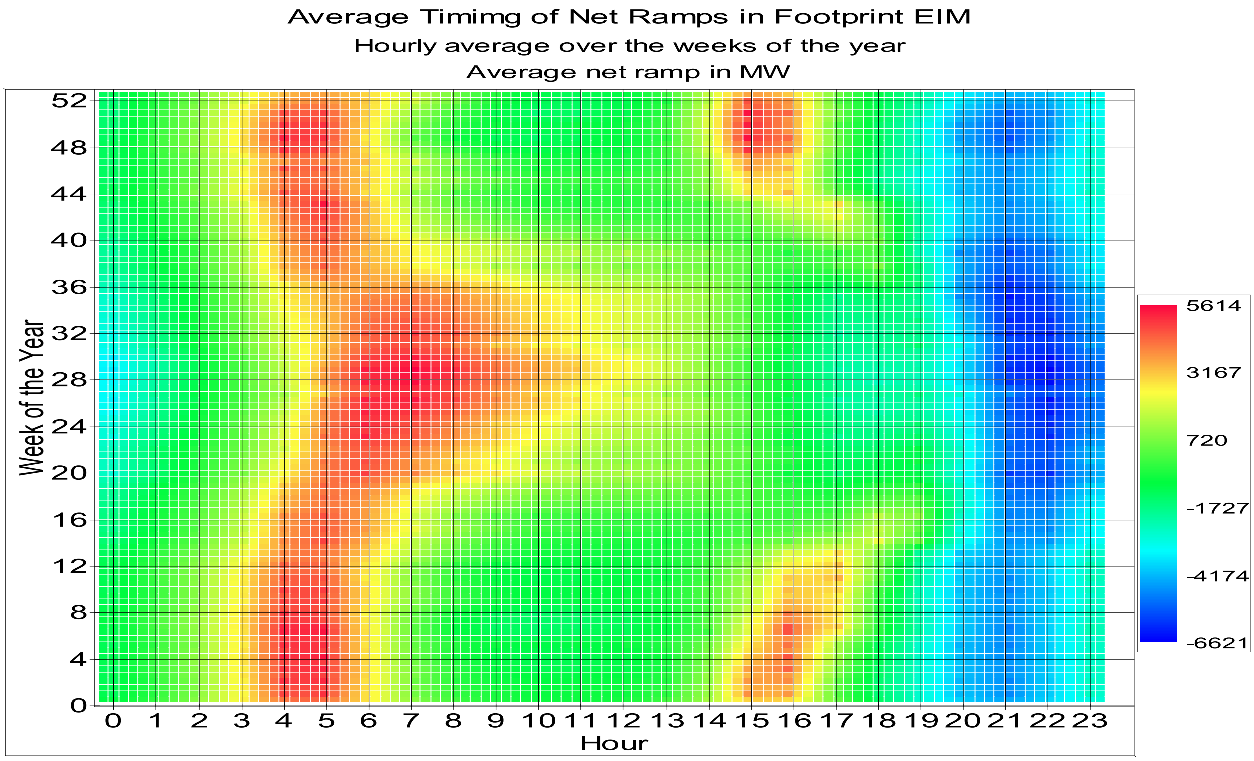

1-Hour Ramp Reduction - WestConnect w/o WAPA Savings over BAU for Regional EIM - Typical Week
Reduction in Ramp Demand (MW/hr)
2000
1500
1000
500
0
-500
-1000
-1500
-2000
0
24
48
72
96
120
144
Hours
Net
Load

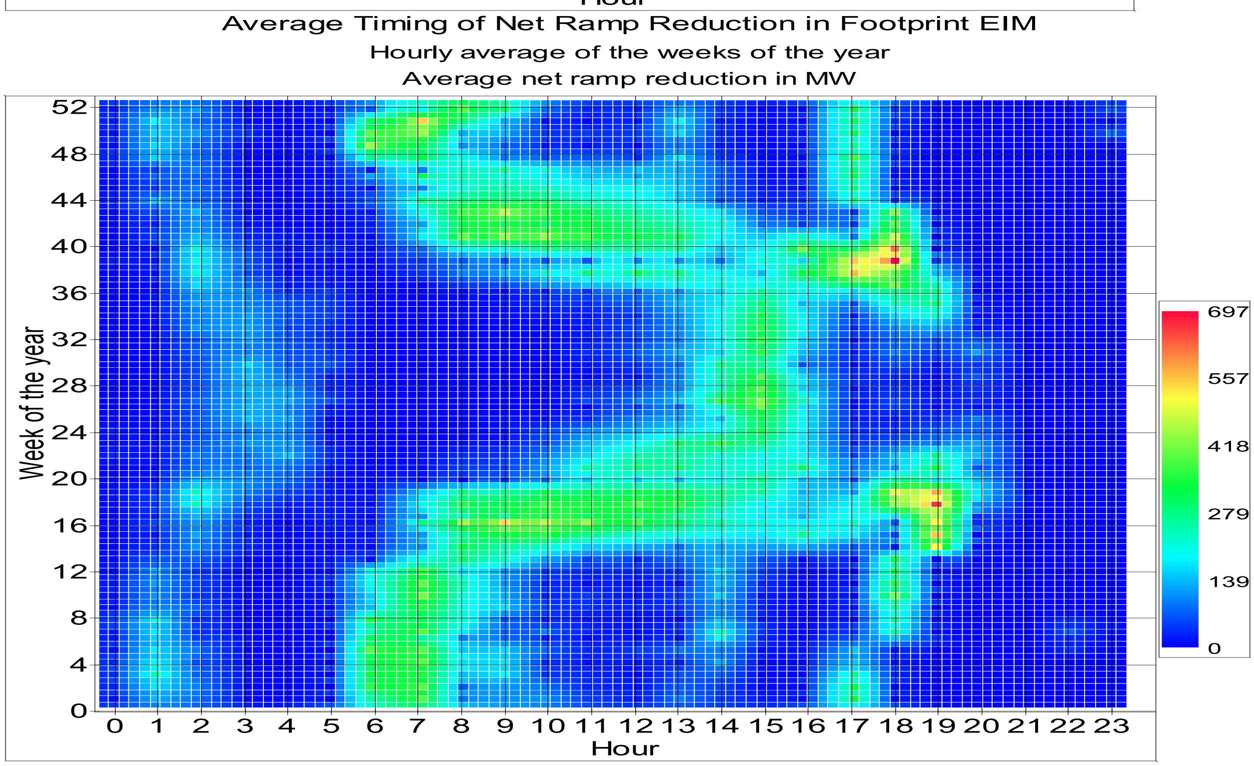

10-Minute Ramp Reduction - WestConnect w/o WAPA Savings over BAU for Regional EIM
Reduction in Ramp Demand (MW/10 min)
1000
500
0
-500
-1000
0
1000
2000
3000
4000
5000
6000
7000
8000
Hour
Net
Load


10-Minute Ramp Reduction - WestConnect w/o WAPA Savings over BAU for Regional EIM - Typical Week
Reduction in Ramp Demand (MW/10 min)
600
400
200
0
-200
-400
-600
0
24
48
72
96
120
144
Hour
Net
Load

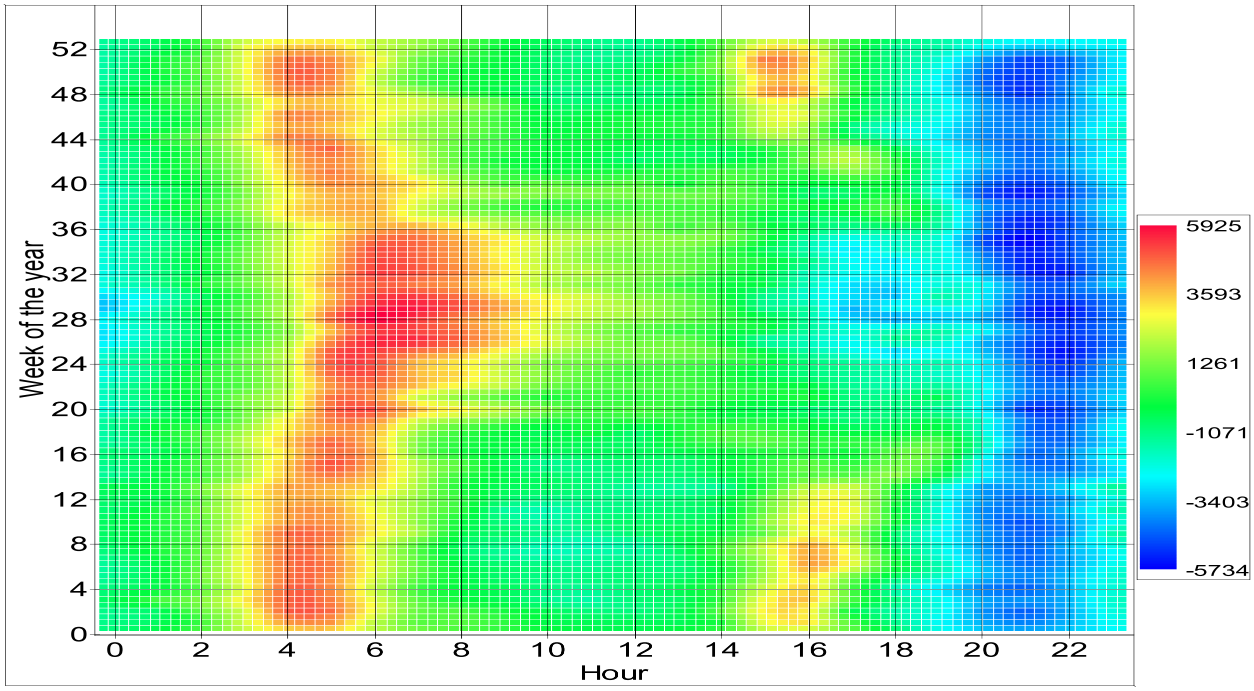
Appendix B. Ramp Timing Plots

This appendix contains ramp and ramp reduction timing plots for each of the cases in this study.

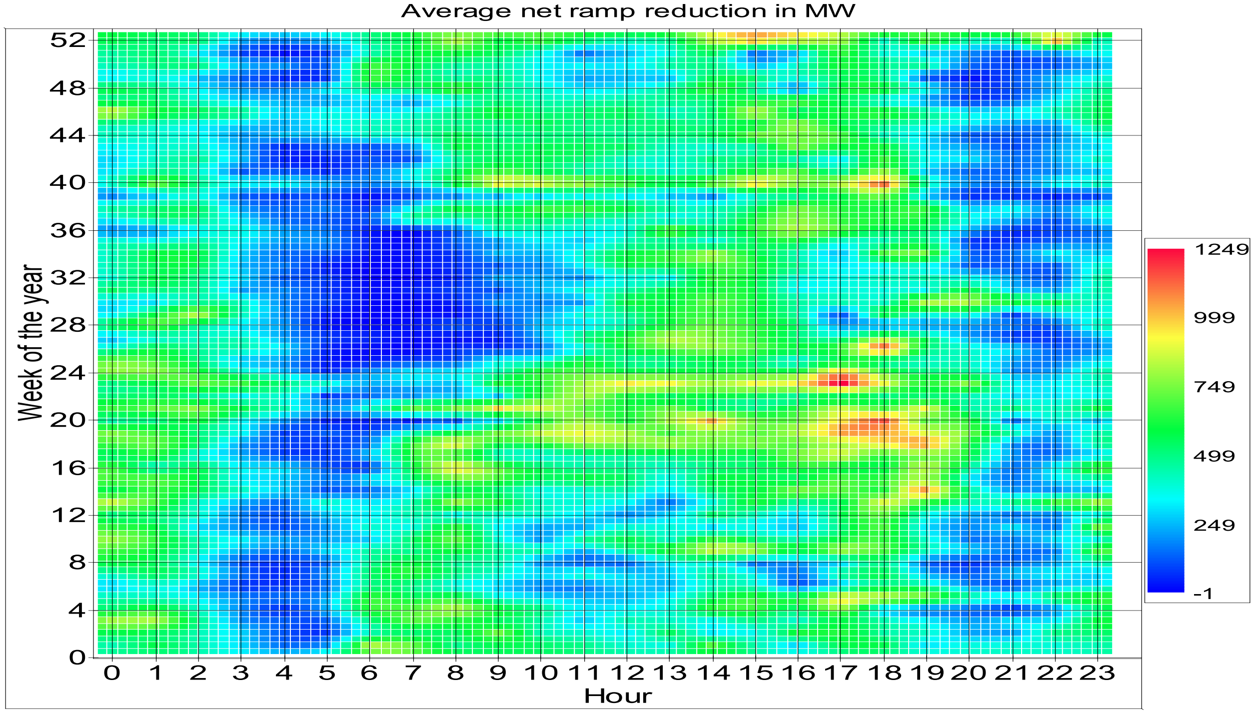




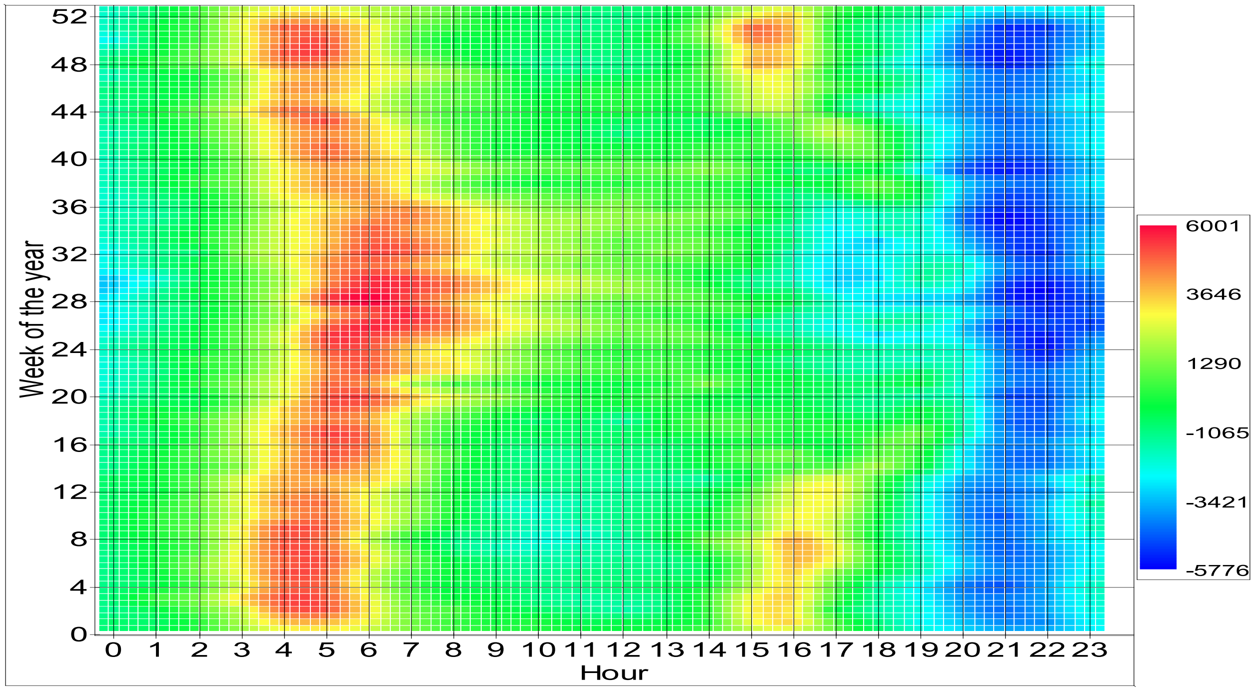
Average Timing of Net Ramps in Footprint EIM w/o BPA
Hourly average over the weeks of the year
Average net ramp in MW



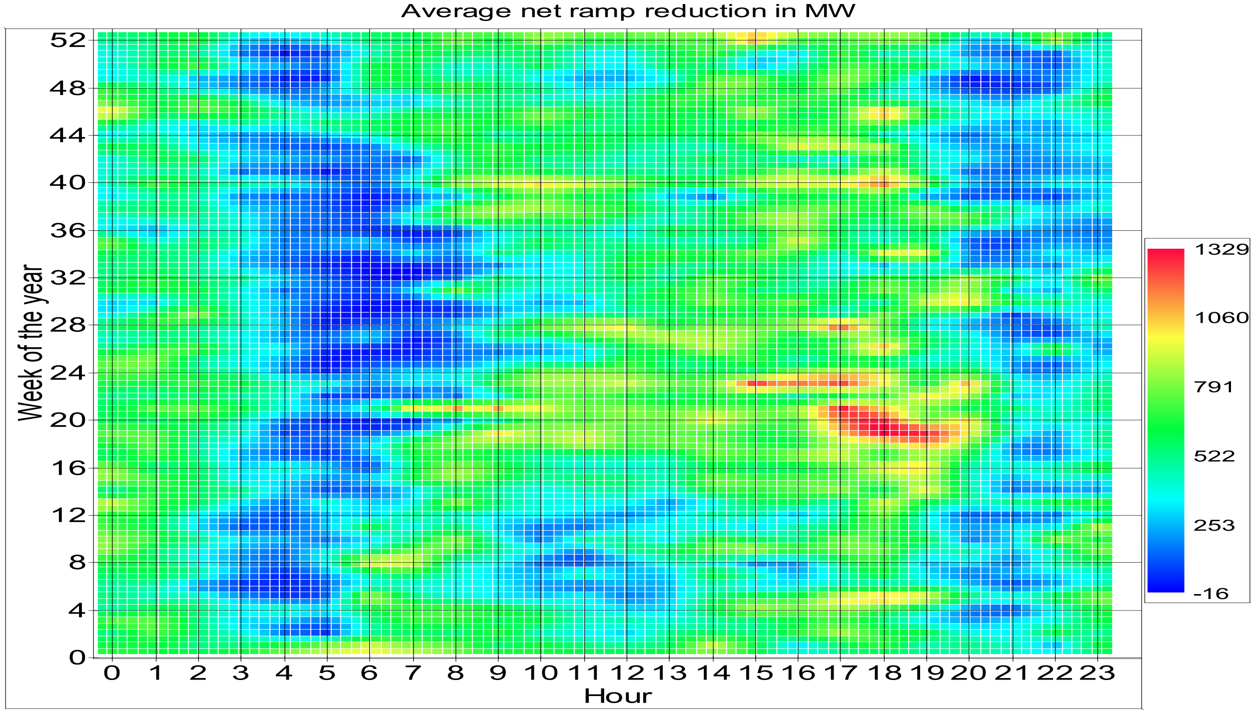
Average Timing of Net Ramps Reduction in Footprint EIM w/o BPA
Hourly average over the weeks of the year
Average net ramp reduction in MW



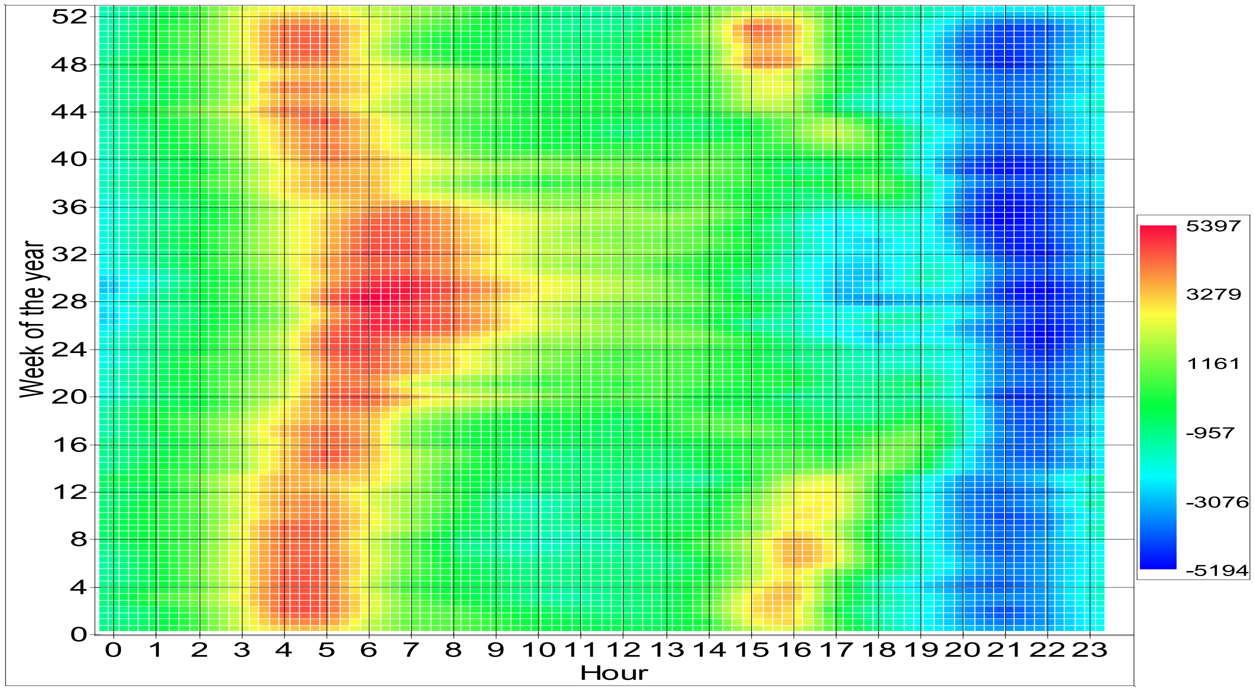
Average Timing of Net Ramps in Footprint EIM w/o WAPA
Hourly average over the weeks of the year
Average net ramp in MW



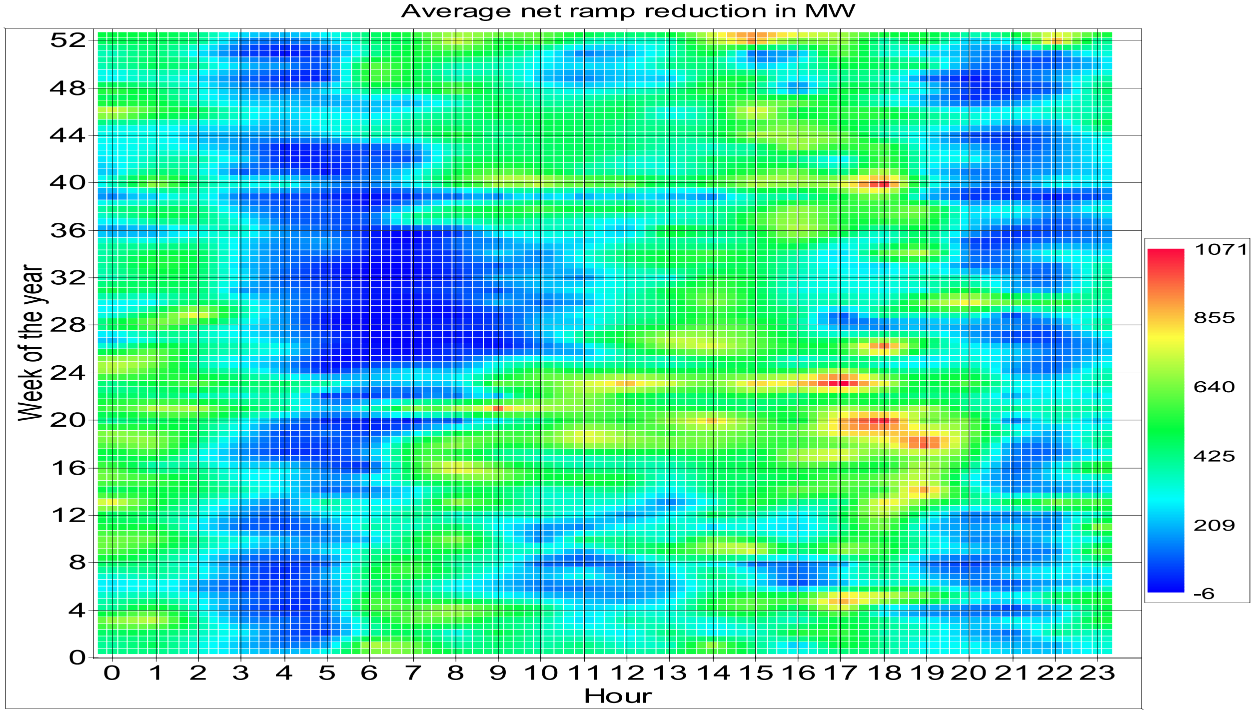
Average Timing of Net Ramps Reduction in Footprint EIM w/o WAPA
Hourly average over the weeks of the year
Average net ramp reduction in MW



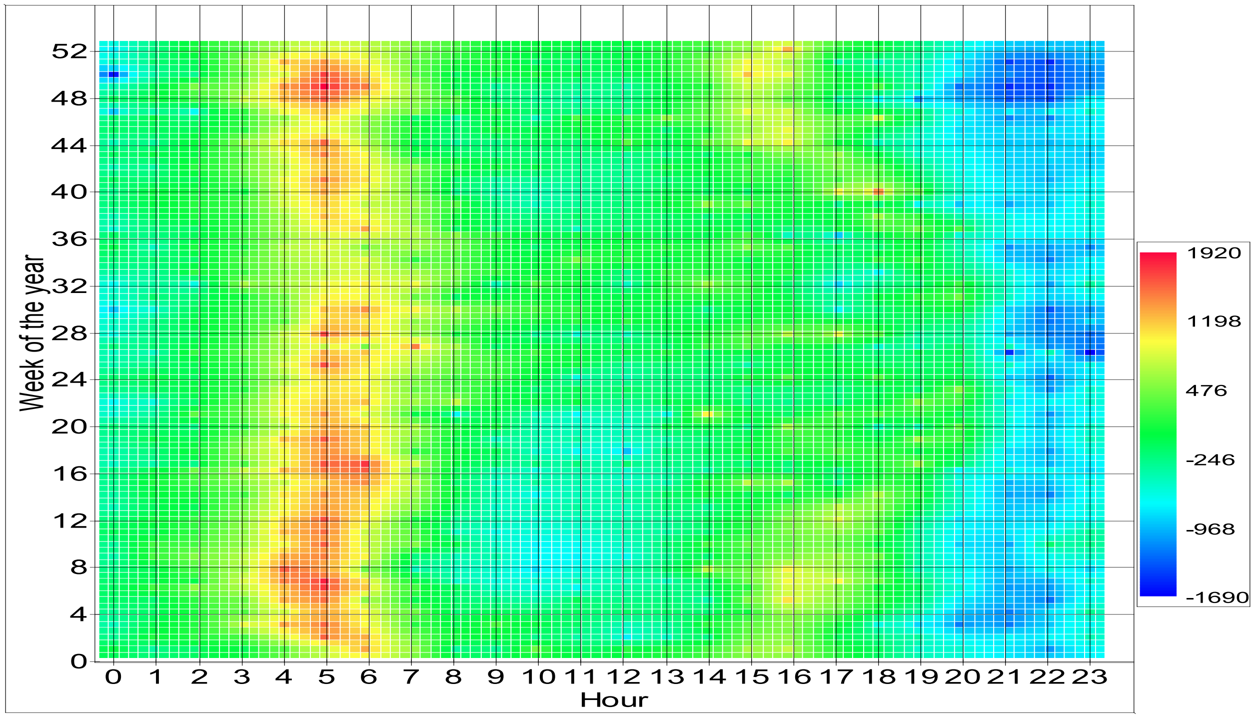
Average Timing of Net Ramps in Footprint EIM w/o BPA, WAPA
Hourly average over the weeks of the year
Average net ramp in MW



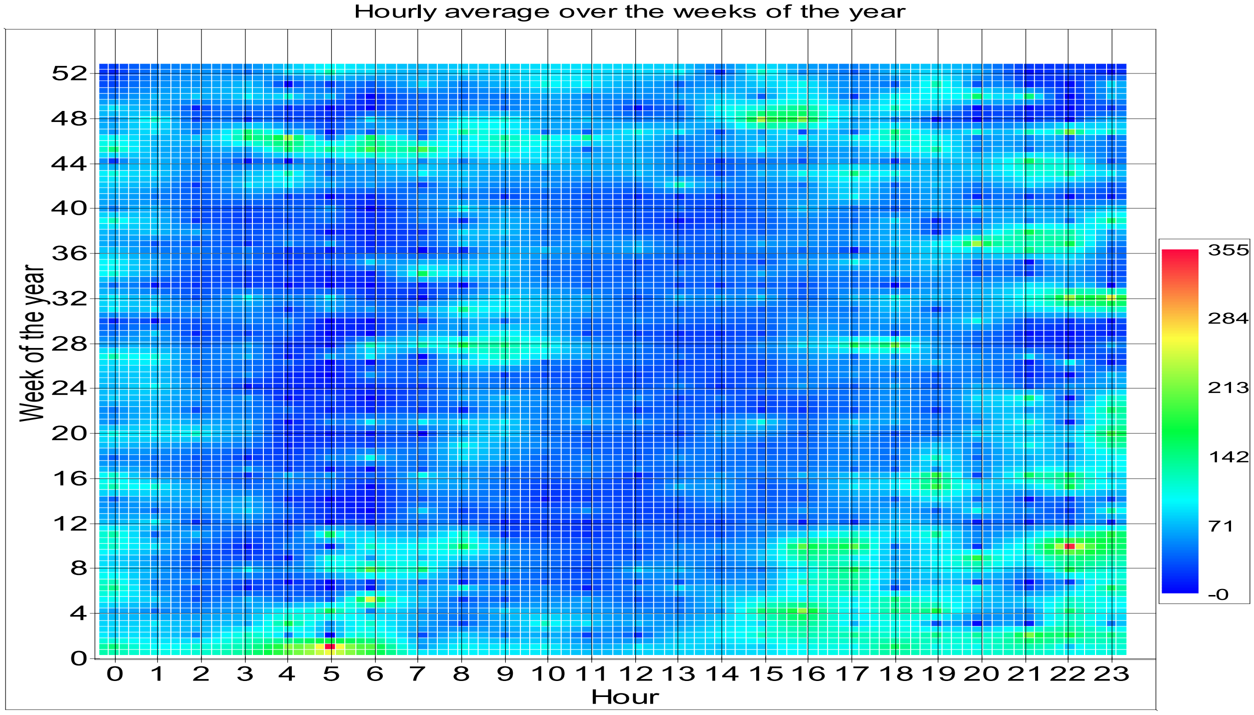
Average Timing of Net Ramps Reduction in Footprint EIM w/o BPA, WAPA
Hourly average over the weeks of the year
Average net ramp reduction in MW



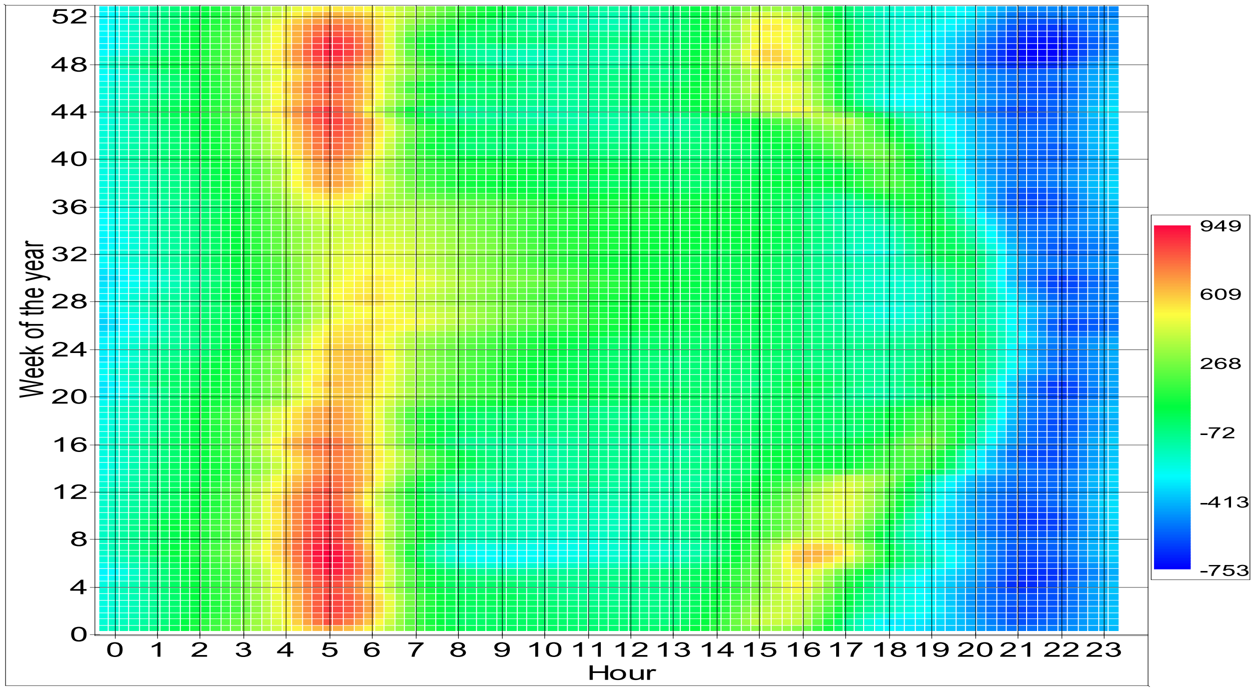
Average Timing of Net Ramps in Columbia Grid
Hourly average over the weeks of the year



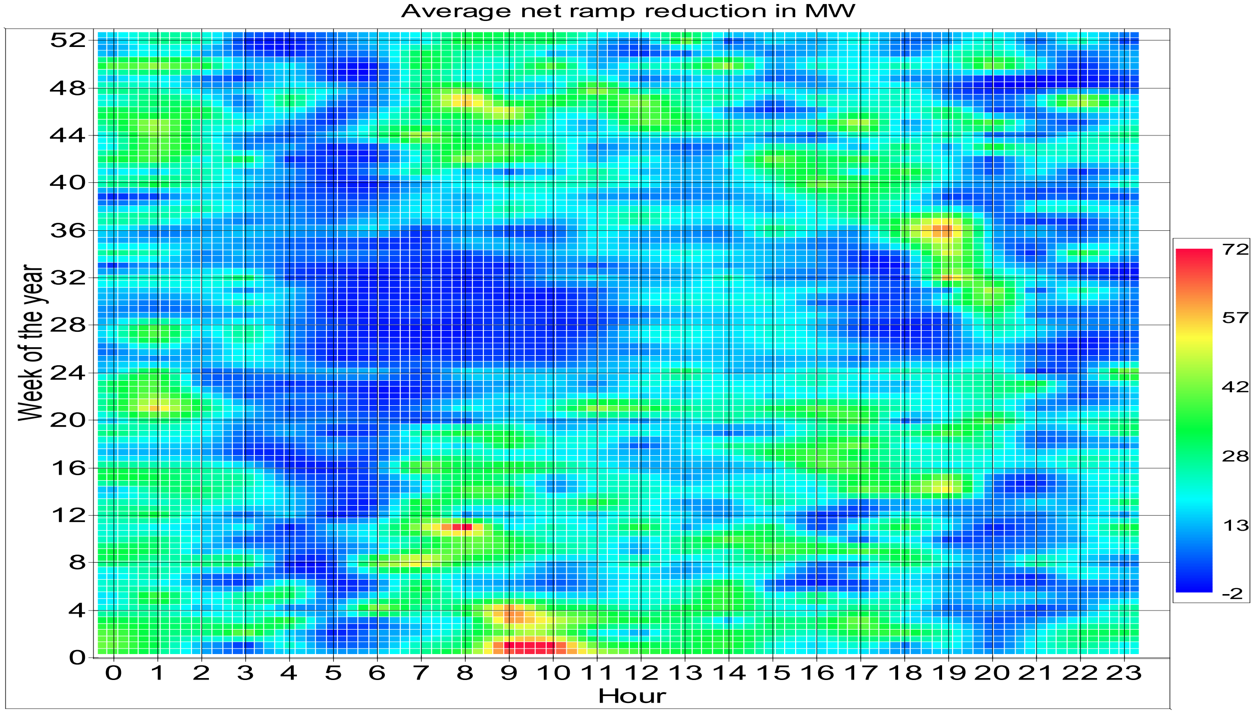
Average Timing of Net Ramp Reduction in Columbia Grid
Effect of WestConnect operating as an EIM versus BAU
Hourly average over the weeks of the year



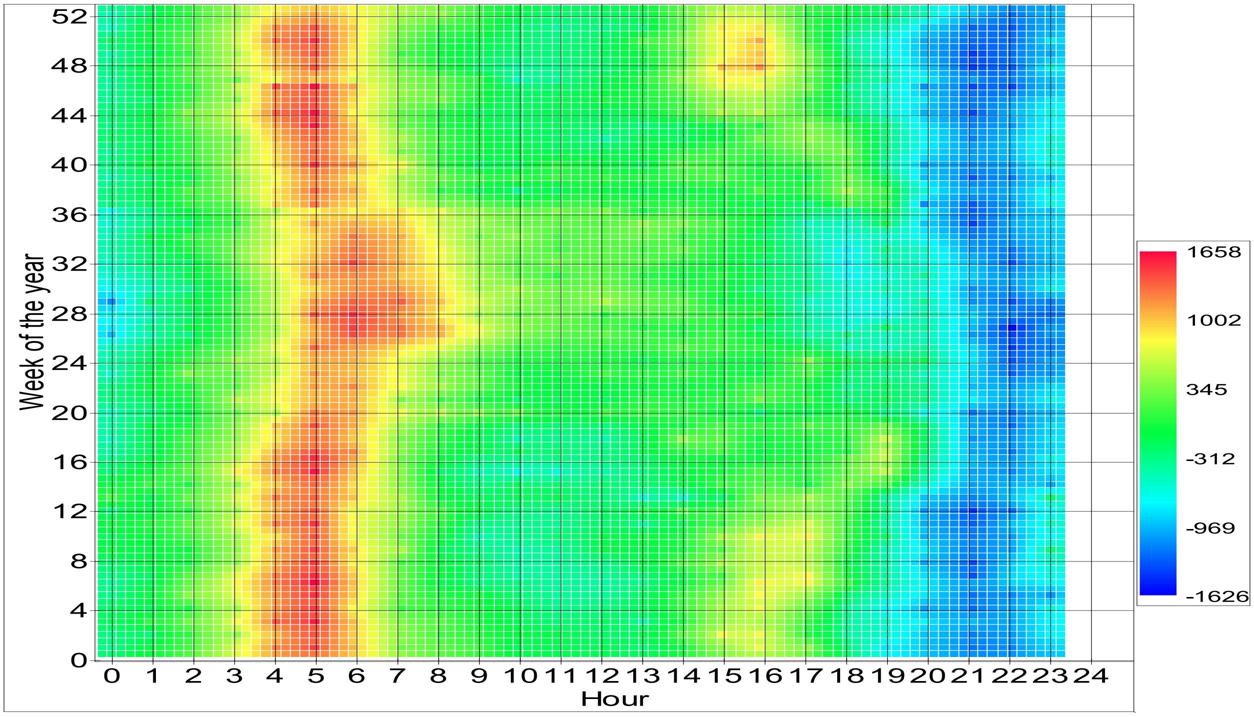
Average Timing of Net Ramps in Columbia Grid Regional EIM w/o BPA
Hourly average over the weeks of the year
Average net ramp in MW



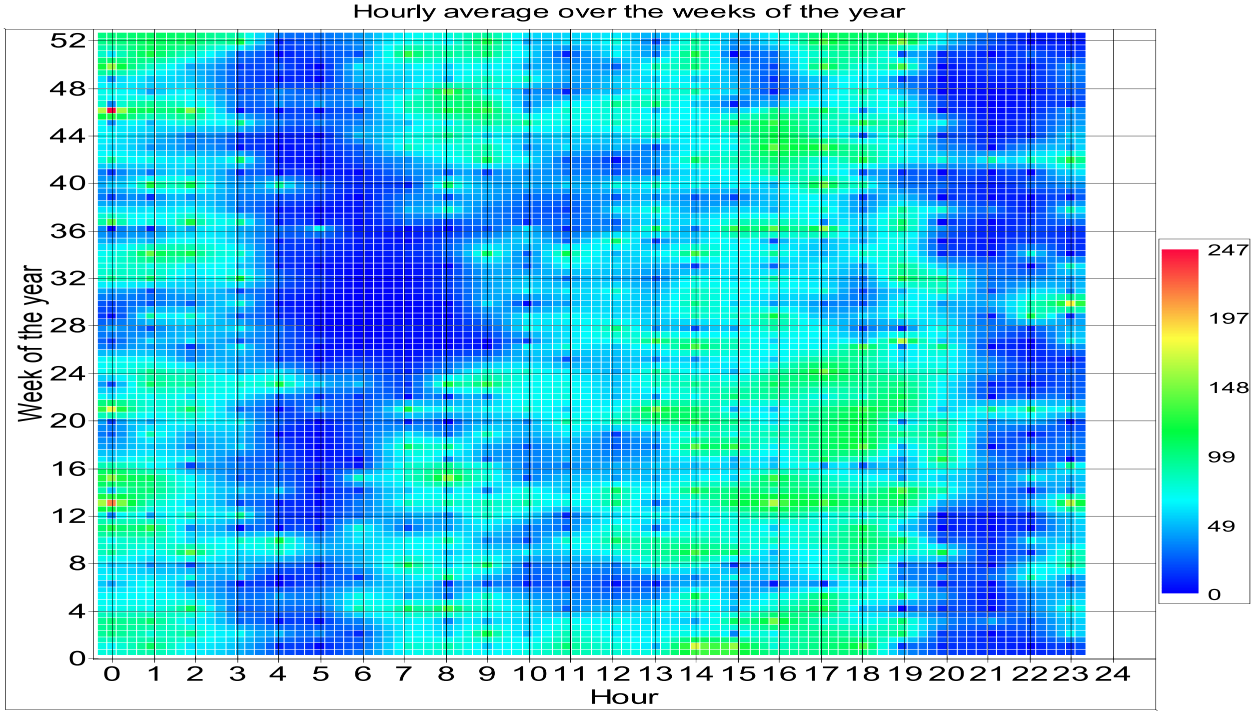
Average Timing of Net Ramps Reduction in Columbia Grid Regional EIM w/o BPA
Hourly average over the weeks of the year
Average net ramp reduction in MW

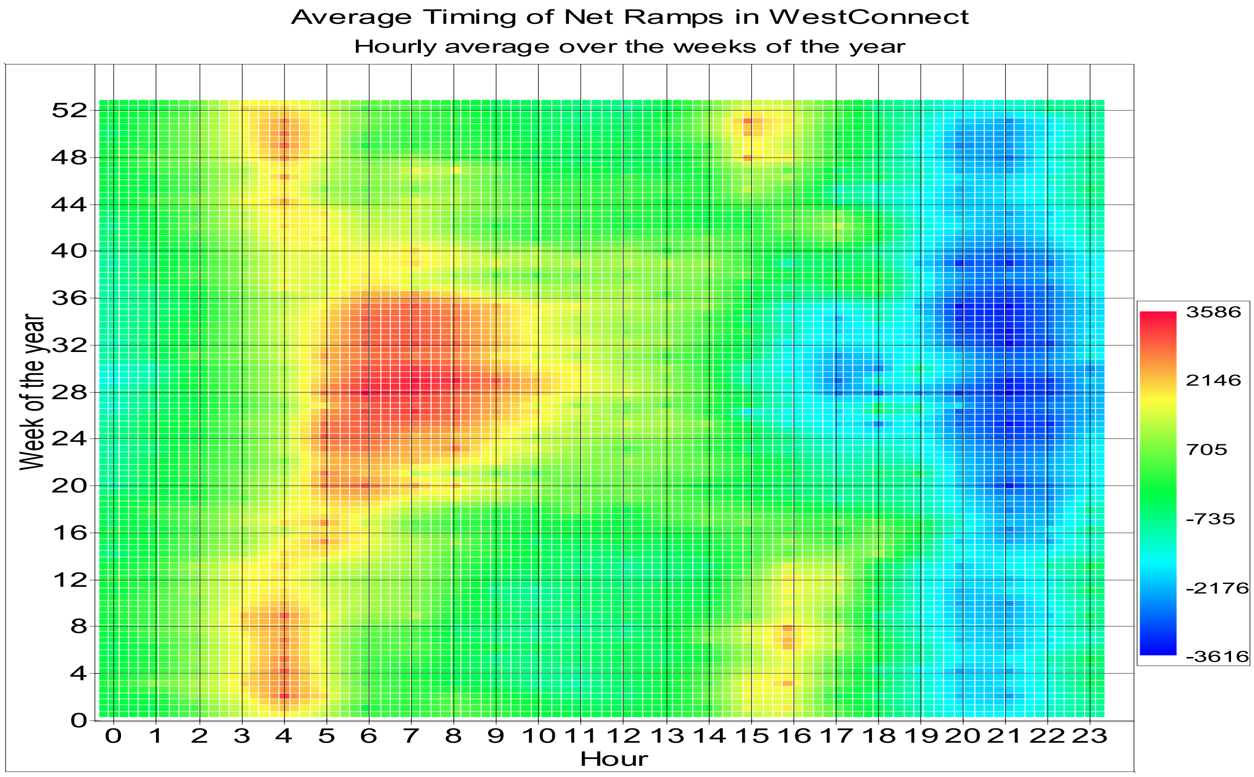


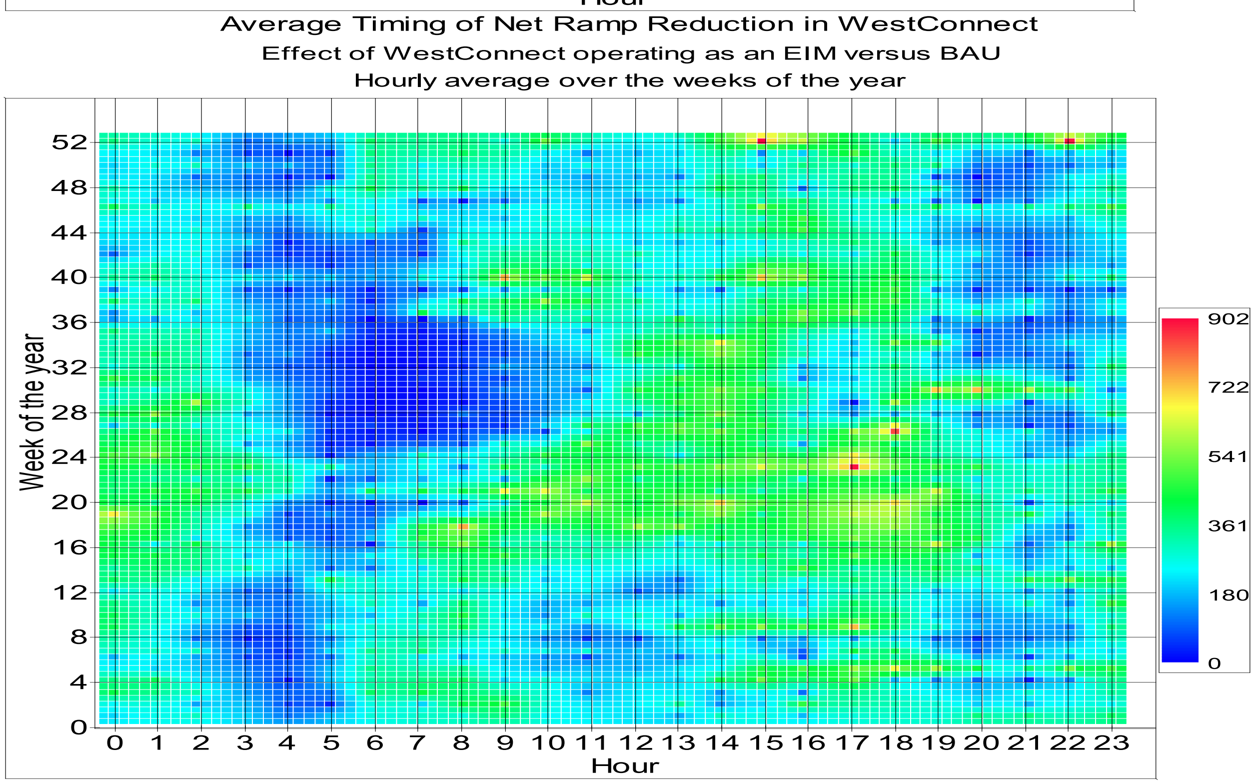
Average Timing of Net Ramps in NTTG
Hourly average over the weeks of the year



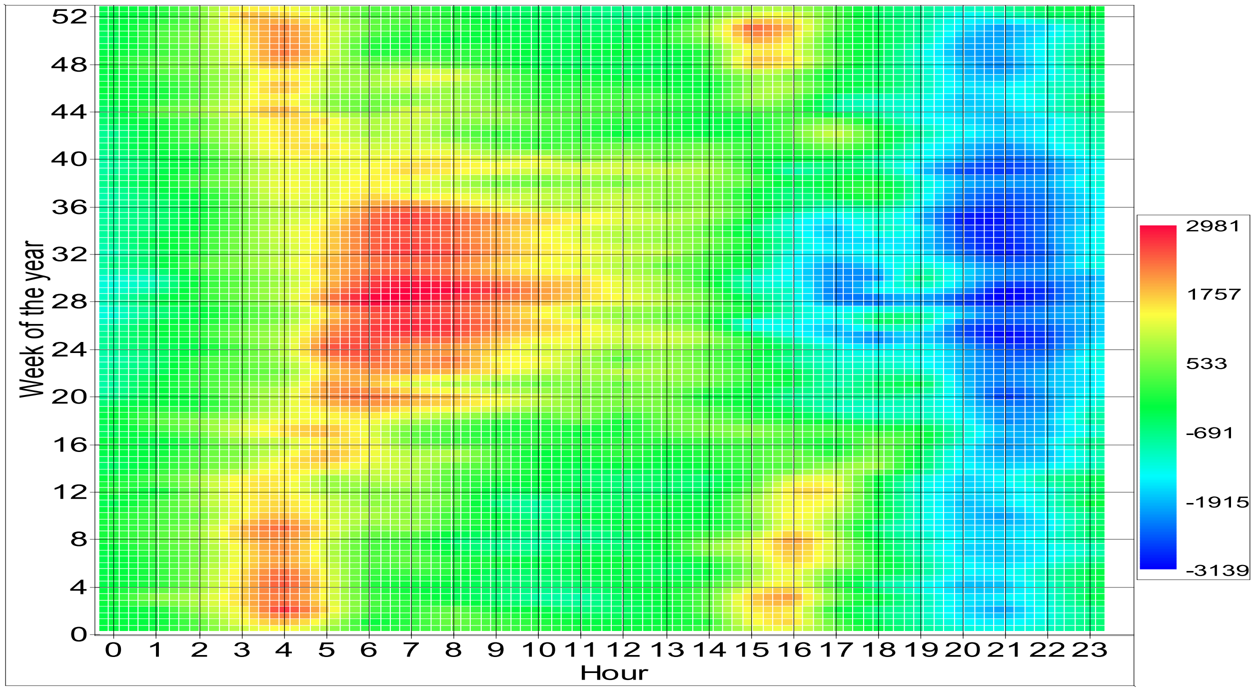
Average Timing of Net Ramp Reduction in NTTG
Effect of NTTG operating as an EIM versus BAU
Hourly average over the weeks of the year




Average Timing of Net Ramps in WestConnect
Hourly average over the weeks of the year
Week of the year
Hour
3586
2146
705
-735
-2176
-3616


Average Timing of Net Ramp Reduction in WestConnect
Effect of WestConnect operating as an EIM versus BAU
Hourly average over the weeks of the year
Week of the year
Hour
902
722
541
361
180
0

Average Timing of Net Ramps in WestConnect Regional EIM w/o WAPA
Hourly average over the weeks of the year
Average net ramp in MW



Average Timing of Net Ramps Reduction in WestConnect Regional EIM w/o WAPA
Hourly average over the weeks of the year
Average net ramp reduction in MW