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Impact of Balancing Areas Size, Obligation Sharing, and Ramping Capability on Wind Integration

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The Impact of Balancing Areas Size, Obligation Sharing, and Ramping Capability on Wind Integration

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Abstract

Balancing area reserve sharing[1] holds the promise of significantly reducing wind integration costs. It also reduces utility costs without wind. Some recent studies of integrating wind into large power systems indicate that wind integration costs may rise more smoothly than previously assumed, based on analysis of smaller power systems. The "hockey stick" pattern of dramatically increasing wind integration cost above some threshold wind penetration may not be as pronounced as expected. The existence and location of this dramatically increasing integration cost could have important implications regarding the cost of achieving 20% of all domestic electricity from wind. This paper examines wind integration costs as a function of balancing area size to determine if the larger system size helps mitigate wind integration cost increases. Using data from Minnesota, we show that ramping requirements can be reduced by balancing area consolidation. We also examine the ERCOT and NYISO sub-hourly energy markets to understand how they incentivize generators to respond to ramping signals without having to explicitly pay for the service. Because markets appear to have the ability of bringing out supply response in sub-hourly energy markets, and because existing thermal resources appear to have significant untapped ramping capability, we believe that a combination of fast energy markets and combined balancing area operations can increase the grid's ability to absorb higher wind penetrations without experiencing significant operational problems or costs.

[1] Balancing area obligation sharing involves the continuous sharing of ACE and imbalance obligations among two or more balancing areas in order to reduce regulation and load following requirements in meeting CPS 1 and 2. It is the continuous analogy to the current practice of sharing contingency response obligations within reserve sharing groups.

Introduction: Power Systems Operation and Wind

During the past several years, the use of wind energy has expanded around the world. In the United States, there were nearly 12 GW of wind capacity online in early 2007 (http://www.awea.org/projects/) and an additional 3 GW of wind is expected to be online by the end of 2007. The growth in actual and prospective wind energy facilities has in part stimulated a number of analyses of power system operations at the same time as additional experience with wind has helped grid operators become familiar with this relatively new energy source.

A significant focus of several wind integration analyses has been on the operational impact that wind has on the grid. These impacts arise from the variable nature of the wind resource and from the difficulty in accurately predicting wind energy hours or days in advance. Wind integration studies prior to 2006 have generally focused on the impact of wind on power system operations within existing balancing area boundaries. A recent study carried out for the Minnesota Public Utilities Commission by EnerNex (2006) examined the impact of a 20% wind penetration (based on energy) statewide, and recognized the interconnection benefits to the MISO energy markets. Miller and Jordon (2006) illustrated the benefits of balancing area consolidation using data from GE Energy (2005) for the New York State Energy Research Development Authority.

Because wind energy is primarily an energy source, the capacity value of wind will be a fraction of its rated nameplate capacity. In the extreme (and highly unlikely) event that wind has no capacity value, any system that is capable of operating in the absence of wind can continue to operate with wind. The installed non-wind generation would be capable of supplying needed capacity and energy during the times that it is needed. Although operational changes would be expected to arise with the addition of wind energy, the sufficiency of the pre-existing system would clearly still be adequate.

However, there has been recent concern about whether sufficient ramping capability exists to help manage the increasing variability that results from significant wind penetrations. Bonneville Power Administration (BPA) recently embarked on a study to determine the extent to which wind forecasts could help reduce wind integration costs. BPA also raised concern about the increased cost of dealing with wind ramp requirements at the Northwest Wind Integration Action Plan Technical Work Group Meeting, Aug 14, 2006. This concern has also been raised by other utilities and grid operators.

To help address the issue of ramping, we obtained data that could be used to calculate system ramping requirements both for individual balancing areas (formerly called control areas) and a combined, integrated balancing area. We used wind data from the Minnesota PUC's 20% Wind Integration Study (EnerNex, 2006), which was simulated by WindLogics to represent a geographically dispersed wind scenario for the study. Because of proprietary concerns, we were unable to secure load data from the utilities, nor were we able to obtain data for the non-wind generation. Instead, we used data from Platts' Basecase to extract hourly load data by balancing authority, and thermal generation data.

In some of our previous work we utilized Platts' hourly thermal generation data to estimate the ability of a balancing authority to provide ramping (Kirby & Milligan, 2005). The Platts data is derived from EPA filings that detail hourly emissions of all thermal power plants in the U.S. The data set shows actual thermal generation on an hourly basis for all thermal units in the footprint. Because this is actual data from 2004, our study year, it is important to note that the thermal units were committed and dispatched for a system with limited wind generation, and caution must be used in interpreting these data. However, our approach was to calculate the actual ramping capability of each thermal unit in MN, based on *actual, observed* data. Specific ramping capability for each generator are very likely to be larger, perhaps significantly so, than what we were able to observe in our data. In addition, any non-thermal generating source, such as hydro and nuclear, were not part of the database. Although nuclear units do not provide any significant ramping capability, hydro generation does.

Because our work was limited to an analysis of hourly data, we are confident that we significantly understate the benefits of combined reserve sharing or balancing area operations. Miller and Jordan (2006) showed that, as measured by standard deviation of load and wind variability, the benefits of combined operations were greater for the 5-minute time slice as compared to the hourly period. The penetration of wind in the NY study was 10%, based on wind rated capacity to system peak load. In contrast, our MN data set is a much higher penetration. To accentuate wind's impact on the system, we used the Platts load data, as reported in 2004, without scaling to the higher load level that was used as the basis of the MN study. Our wind penetration is therefore approximately 30% based on energy, and approximately 50% based on capacity. Our system representation shows an annual combined peak load of 11,378 MW with rated wind capacity of 5,688 MW.

Our analysis first examined the impact that wind has on balancing area ramp requirements, and compared the need for ramping under two scenarios: (1) balancing areas continue with separate operation, obtaining all needed ramping from within the area, and (2) the state of MN operates as a single balancing area. This second scenario was the basis for the MN 20% Wind Integration Study. Contrary to the MN study, we ignore any interaction with the MISO energy market or with generating units that are outside the MN footprint. This puts the entire ramping burden on generators that are within the balancing area. First we describe the demand for ramping capability with wind. We then provide an analysis of the supply of existing ramping capability, compares it to the demand, and discusses how sub-hourly energy markets provide and price ramping services.

Ramping Requirements for Load and Wind

It is well known that larger balancing areas can more easily manage variability. A recent analysis by Miller & Jordon (2006) showed the benefit of aggregation in New York. The analysis was based on data used for a wind integration study, and illustrates the benefit of combining the transmission zones in the state. The benefits of consolidating loads, but without wind, are modest in the hourly time frame, but are more significant in the 5-

minute time frame. Consolidation with 3,000 MW of wind added to the system was more beneficial in both time frames.

Our analysis differs from the NY analysis because we focus on ramping characteristics, both with and without wind. Our analysis first examines the demand, or need for, ramping based on load and wind characteristics. We calculate the ramping needs for MN with and without balancing area consolidation, and look at load separately from wind. Although our concern is less with the impact that wind has on ramping requirements, we show data that illustrates how ramping requirements change with wind.

Minnesota is divided into four balancing areas for our analysis: Great River Energy, Minnesota Power Company, Northern States Power, and Otter Tail Power. Figure 1 shows the approximate balancing areas.

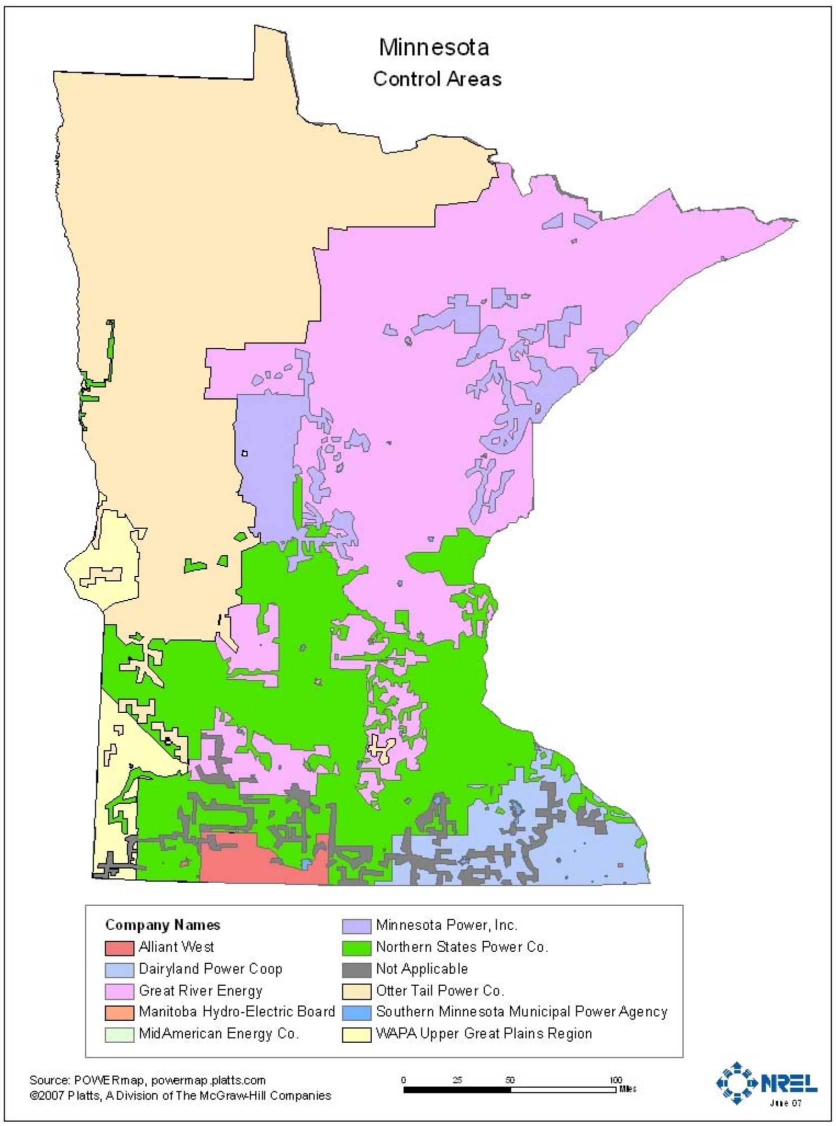

Figure 1. Balancing areas in Minnesota.

Ramping requirements have some degree of statistical independence, depending on the time frame. For relatively long time frames such as one hour, this independence is somewhat limited for load because of the prominent daily load cycle. During the morning load pickup, the general trend of load is increasing, which requires positive ramping from units that are on economic dispatch. Likewise, during the evening load drop off, the decrease in load requires negative ramping from the dispatch stack. For neighboring balancing areas, the morning load pickup and evening load drop off will likely be fairly correlated. This means that during those hours, balancing area consolidation benefits for load ramping alone may be minimal.

Figure 2 illustrates the benefit of balancing area consolidation with wind added to the system. The figure is based on data we used for this project, selected to illustrate how benefits of combined operations work. The upper panel of the graph shows one day of hourly ramp requirements for wind and load together, based on separate balancing area operations. The upper trace (solid blue) shows the total up-ramp requirements for the day. The green trace shows the hourly down-ramp requirements for the same period, assuming separate operations. The graph clearly illustrates that there are hours when some balancing areas require up-ramp capability at the same time that other areas require down-ramp capability. During these hours, more physical and economic efficiency can be achieved by offsetting the positive and negative ramping requirements, to the extent possible. This results in the combined balancing area ramp requirement, which is superimposed in yellow on the upper panel of the graph. The reduction in required ramping that can be achieved by combining operations is shown in the middle panel of the graph, and is called the ramp penalty.

To better quantify the benefits of combined operations, we develop a series of definitions and metrics. The *dominant ramp* is the maximum of the up-ramp and down-ramp for a given hour. The dominant ramp has the same sign as the required ramp for combined operations. In Figure 2 we can see that the dominant ramp is positive until 1:00 PM, remaining negative for the remainder of the day. The *secondary ramp* is the ramp that is in the opposite direction as the dominant ramp. We define the *ramp penalty* as the difference between the dominant ramps required by separate systems operation and combined operation.

Excess ramping is a symmetrical positive and negative ramp. For example, in Figure 2 at 5:00 AM there is a positive ramp of about 1,000 MW at the same time there is a negative ramp of about 500 MW. If the balancing area were to combine, the dominant ramp of 1,000 MW could be reduced to 500 MW. This reduction in the dominant ramp is the ramp penalty for that hour. During this hour there is a reduction of the dominant ramp of 500 MW and an elimination of the secondary ramp of -500 MW. The excess ramp is therefore in both directions, and appears in the lower panel of Figure 2.

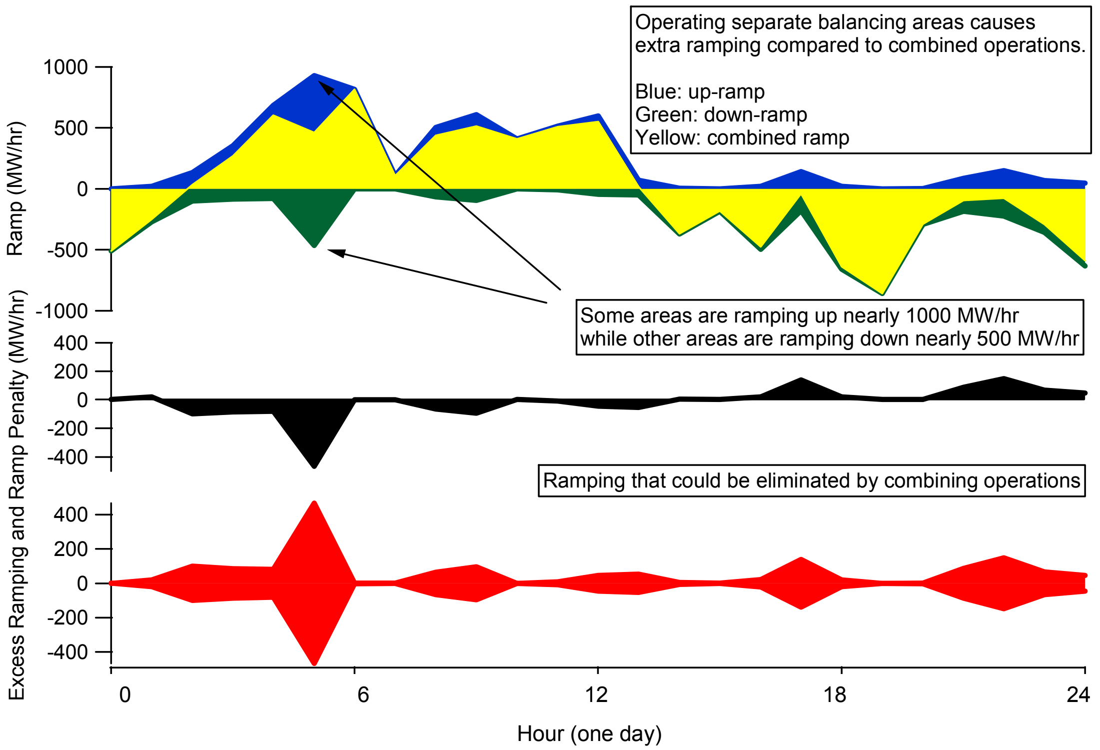

Figure 2. Potential benefits of combined balancing area operations.

The general trend of the ramp penalty shows that during the early morning load pickup, the combined wind and load ramp requirement is increasing generally, but some areas are experiencing a need for down-ramp capability during that time. The combined system generally needs up-ramping during the morning, and down ramping during the evening. But as the graph makes clear, there are individual needs for down-ramp capability during the morning, and up-ramp capability during the evening. Combining operations across the balancing areas will reduce overall ramping needs.

The next section describes the benefits of combined operations in the absence of wind.

Load Ramping Requirements: Benefits of Combined Operations

In the 1-hour time frame, the benefit of combining balancing area operations is less than that experienced in the sub-hourly time frame because of the relatively high degree of correlation between hourly load and ramp requirements. Figure 3 shows the combined load in the upper panel, and the required ramping in the lower panel.

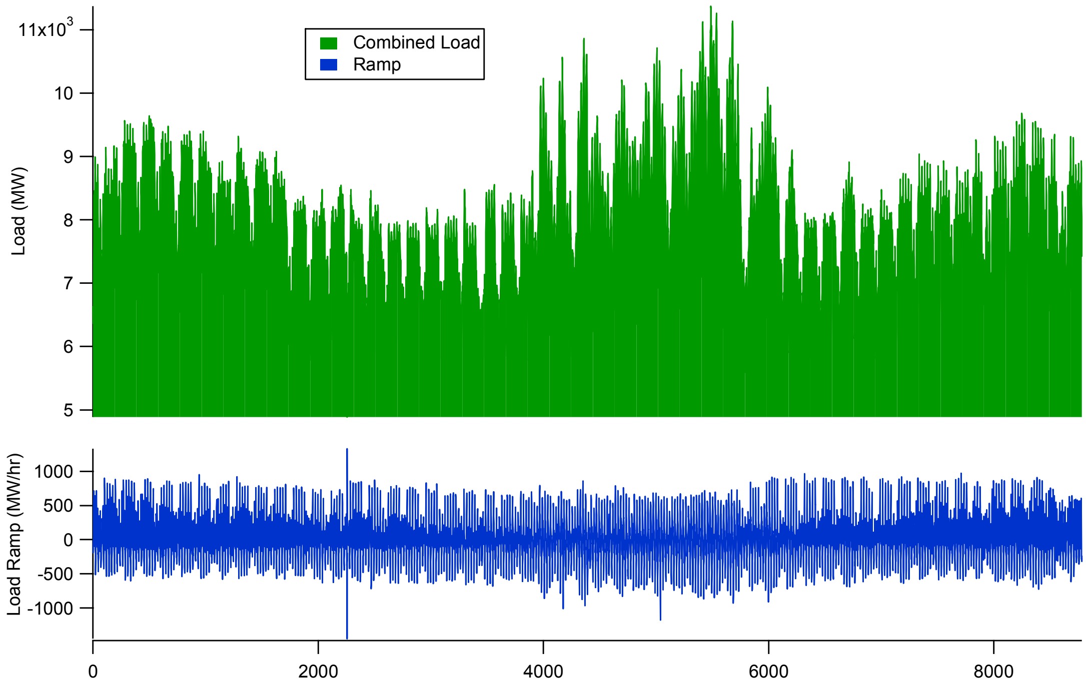

Figure 3. Combined Minnesota loads and ramping requirements.

To calculate the benefits of combined operations, the ramping requirements for each balancing area were first calculated separately. Up ramp requirements are not netted with down ramp requirements because each area must supply only its own loads in this scenario. Figure 4 shows the up-ramp and down-ramp requirements in the upper panel of the graph, assuming that each balancing area operates independently. Superimposed on this is the ramp penalty that is imposed by foregoing joint operations, using the same calculation as illustrated in Figure 2.The ramp penalty is also shown in the middle panel of Figure 4 for clarity.

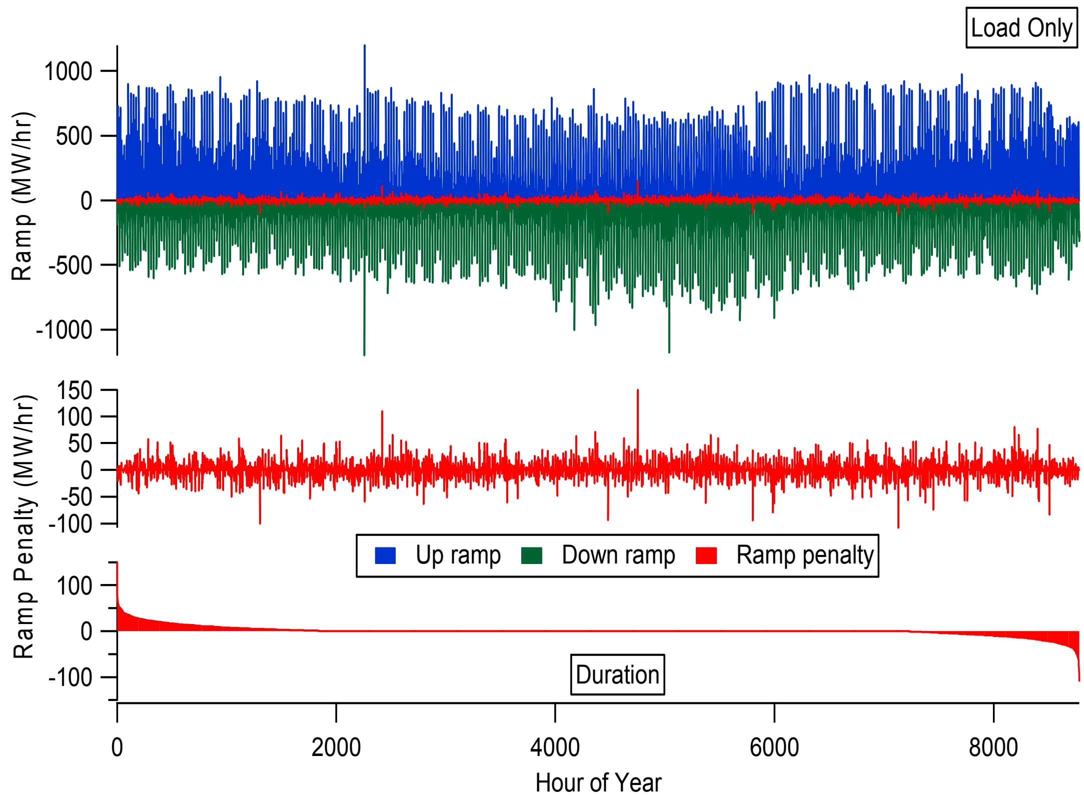

Figure 4. Ramping requirements and penalty, load only.

Another way to view the ramp penalty is as a duration curve. The bottom panel of Figure 4 shows the ramp penalty duration curve and is based on the data represented in the middle panel.

We can also compare the ramp penalty with the excess ramp chronologically and as duration curves. Figure 5 shows that the excess ramping is nearly always non-zero, although it is small for many hours of the year.

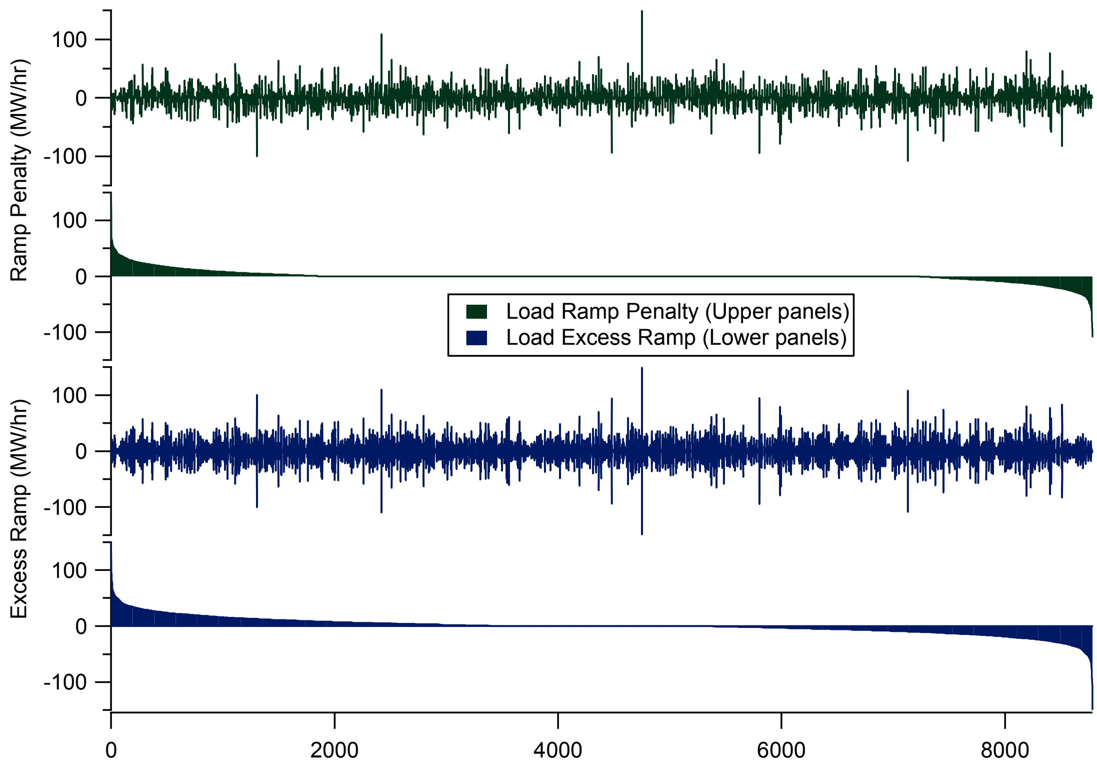

Figure 5. Ramp penalty and excess ramp, load only.

It is clear that there are some ramping benefits that occur in the hourly time frame, but this benefit is not large. Based on the analysis of Miller & Jordan, we expect that the benefit would be larger in a faster time scale that shows less correlation across balancing areas. We know that the benefit is substantial in the minute-to-minute regulation time frame, with regulation requirement rising only with the square-root-of-the-sum-of-the-squares of the individual areas requirements.

Wind Ramping Behavior: Benefits of Combined Operations

To obtain some insight into the combined behavior of wind plants across the region, this section illustrates how the ramping behavior of wind is a function of the footprint of the wind resource and the size of the balancing area. It is important to realize that the individual or combined movements of *wind* do not need to be matched by the remaining generation on the system. Instead, the system operator must take action to balance the aggregate load with aggregate generation. The required operator responses to variations in wind would be carried out in the context of the overall system, which is analyzed in the following section.

Regional wind resources' ramping behavior is damped compared to individual sites (Wan, 2004). Figure 6 is based on a comparison of wind that is separated by balancing area, and shows the sum of the individual up-ramps and down-ramps of the wind alone. The blue and green in the upper panel represent the separate up-ramp and down-ramp characteristics of wind, and the red trace illustrates the ramp penalty that occurs if the wind ramps are viewed within each balancing area. The middle panel zooms in on the chronological ramp penalty, and the bottom panel shows the duration curve for the ramp penalty.

It is clear that wind aggregation has a more dramatic impact on ramping than load aggregation. Figure 6 shows that the maximum up-ramp penalty is 482 MW, and the maximum down-ramp penalty is -382 MW. The average ramp penalty is approximately zero, which is expected, and implies that the impact of this ramp is a capacity impact, not an energy impact. This issue is discussed in more detail in a later section of this paper.

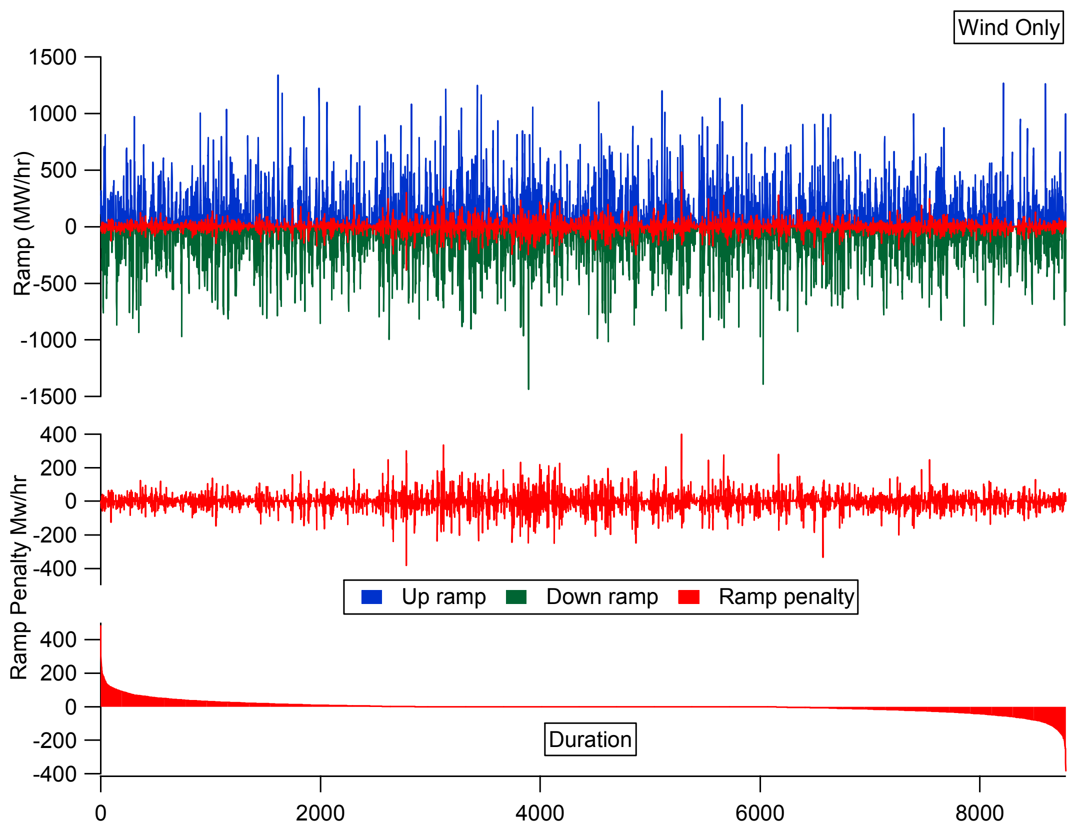

Figure 6. Wind plant hourly ramp behavior and ramp penalty for separate balancing areas.

The ramp duration penalty curve, shown in the bottom panel of Figure 6, shows the most significant impact occurs at the tails of the distribution. Based on this data set, the maximum combined wind-only ramp is 1340 MW/hr, and the maximum ramp penalty is 482 MW/hr.

It is also useful to examine the excess ramp results. Figure 7 is similar to Figure 5, except that it shows the wind-only excess ramp and ramp penalty. The scale of the excess ramp for wind is about four times greater than for load alone. Comparing the two duration curves, we see that excess wind ramps are more prevalent than the reduction in primary ramp, as shown by the ramp penalty duration curve. However, it is important to note that the wind-only behavior, although interesting, does not provide an estimate of what the system needs are.

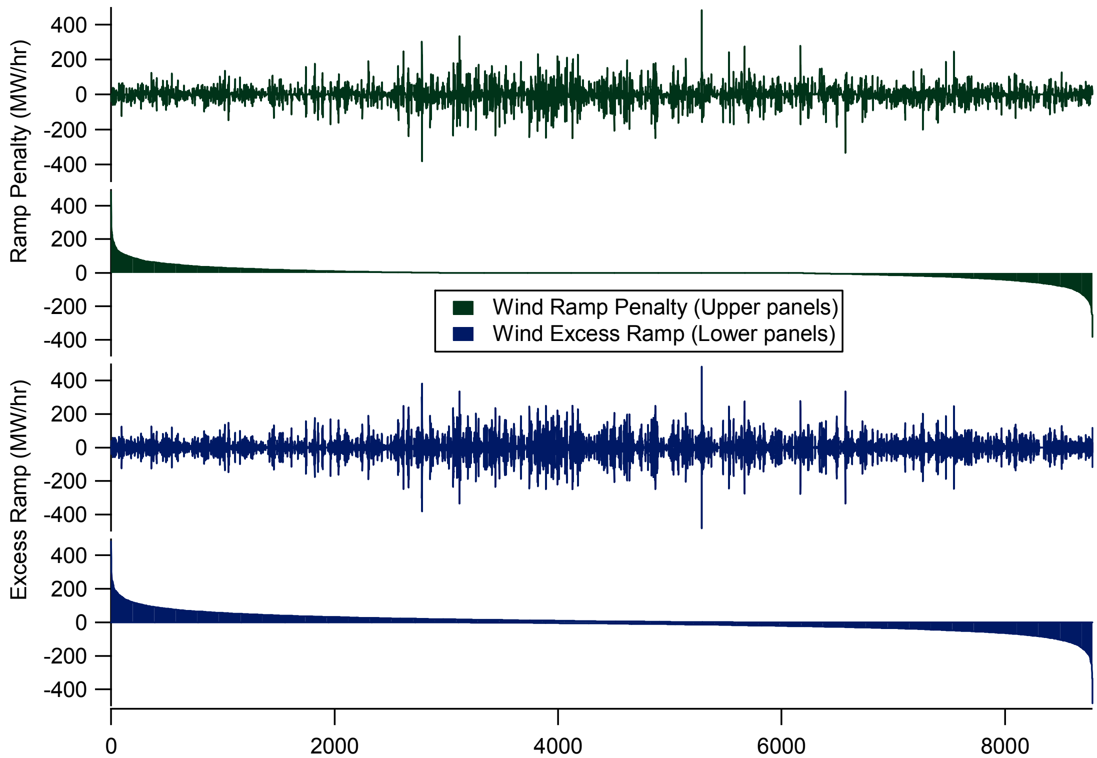

Figure 7. Ramp penalty and excess ramp, wind only.

Load and Wind Ramping Requirements: Benefits of Combined Operations

To run the grid effectively and reliably, the system operator must balance aggregate loads and aggregate resources within statistical tolerances. In an hourly time frame, this implies that the load, less wind generation, must be matched by conventional resources (ignoring interchanges for simplicity). Figure 8 is similar to the previous figures, and shows the net load and wind up-ramp requirements, down-ramp requirements (both assuming separate balancing-area operations), and the resulting ramp penalty. It is clear from comparing Figure 8 with Figure 4 and Figure 6 that combined wind and load have similar magnitude ramping requirements as the ramping requirements of wind alone. It is also clear that combined operations will have a significant impact on the tails of the ramp duration curve.

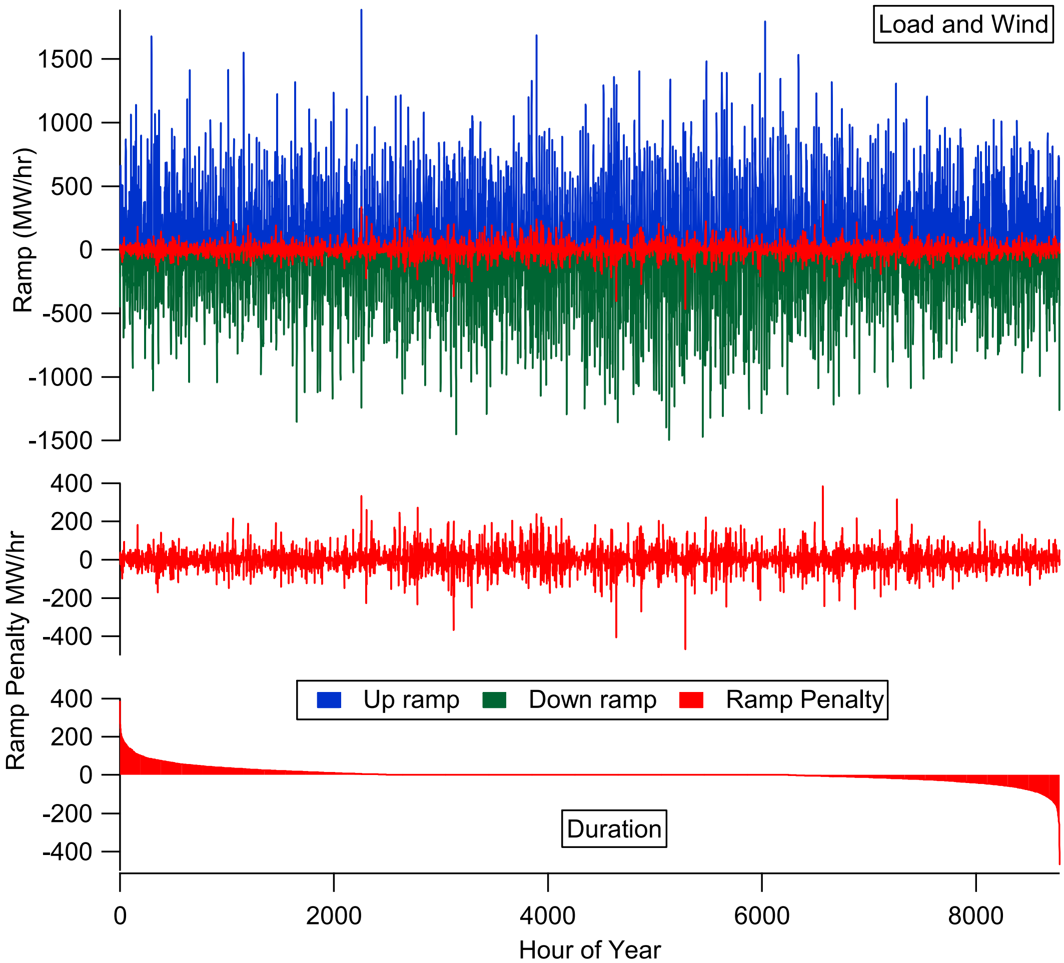

Figure 8. Ramp penalty and duration curve, load and wind.

Figure 9 compares the ramp penalty with the excess ramp requirement for the load with wind case. The scale of the ramp penalty and excess ramp is similar to the wind-only case. It is clear that balancing area consolidation offers the promise of significantly reducing hourly ramp requirements in systems with high wind penetration.

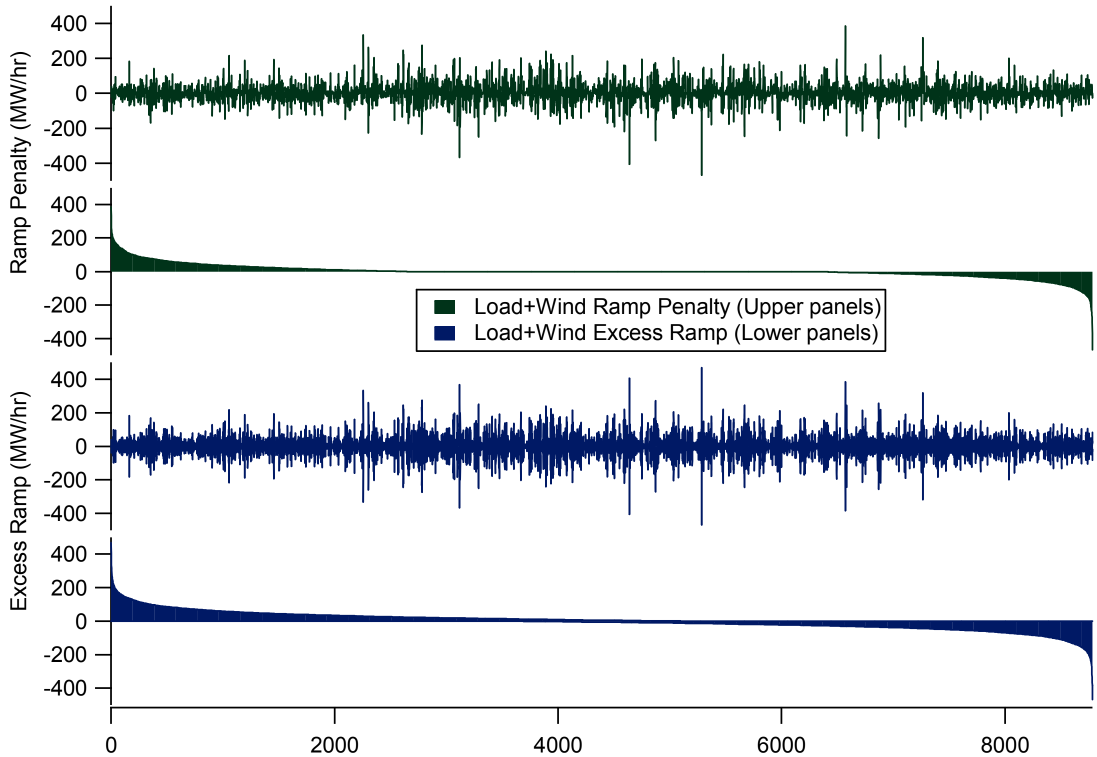

Figure 9. Ramp penalty and excess ramp, load and wind.

Seasonal Ramp Penalties

Because of the seasonal differences in load and wind, we repeated the analysis for each of the four seasons. Based on load characteristics, we separated the seasons as indicated in Table 1.

Table 1. Seasonal Definitions

Season	Start Date
Spring	March 15
Summer	June 15
Fall	September 15
Winter	November 15

The seasonal graphs, Figure 10 through Figure 13, illustrate each seasons' chronological ramp penalty (load and wind) and duration in the upper panels, followed by the chronological excess ramp and excess ramp duration curves in the bottom panels.

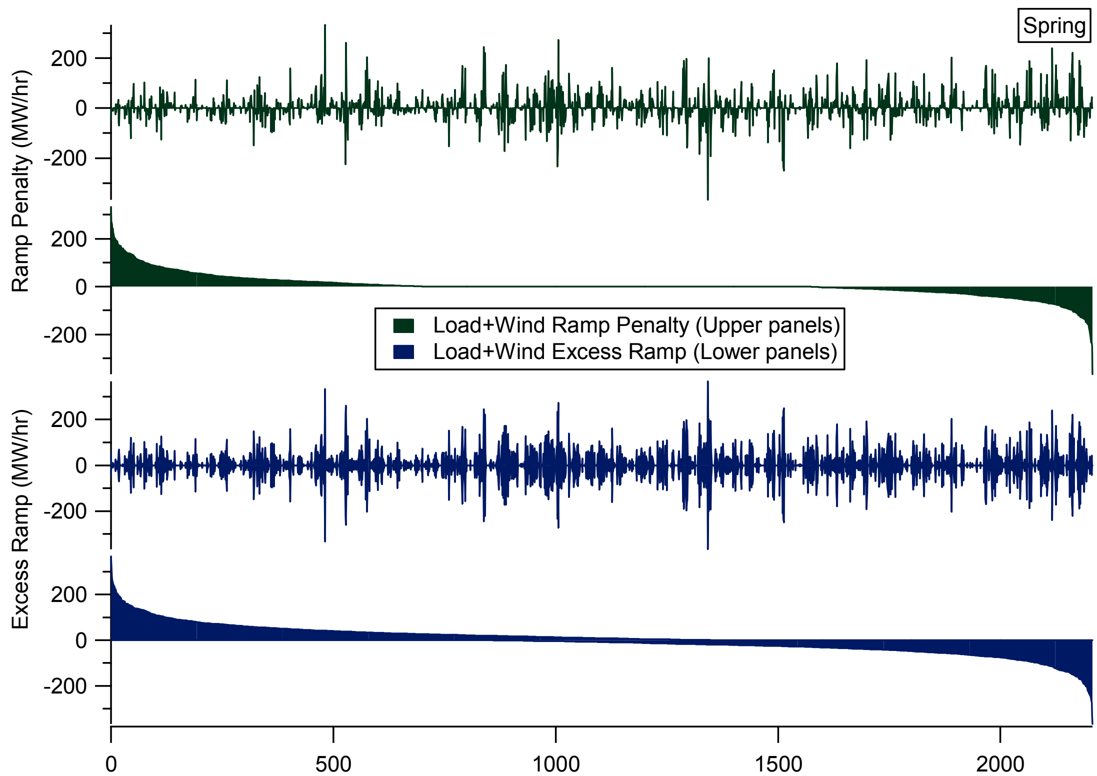

Figure 10. Spring ramp penalty and excess ramp, load and wind.

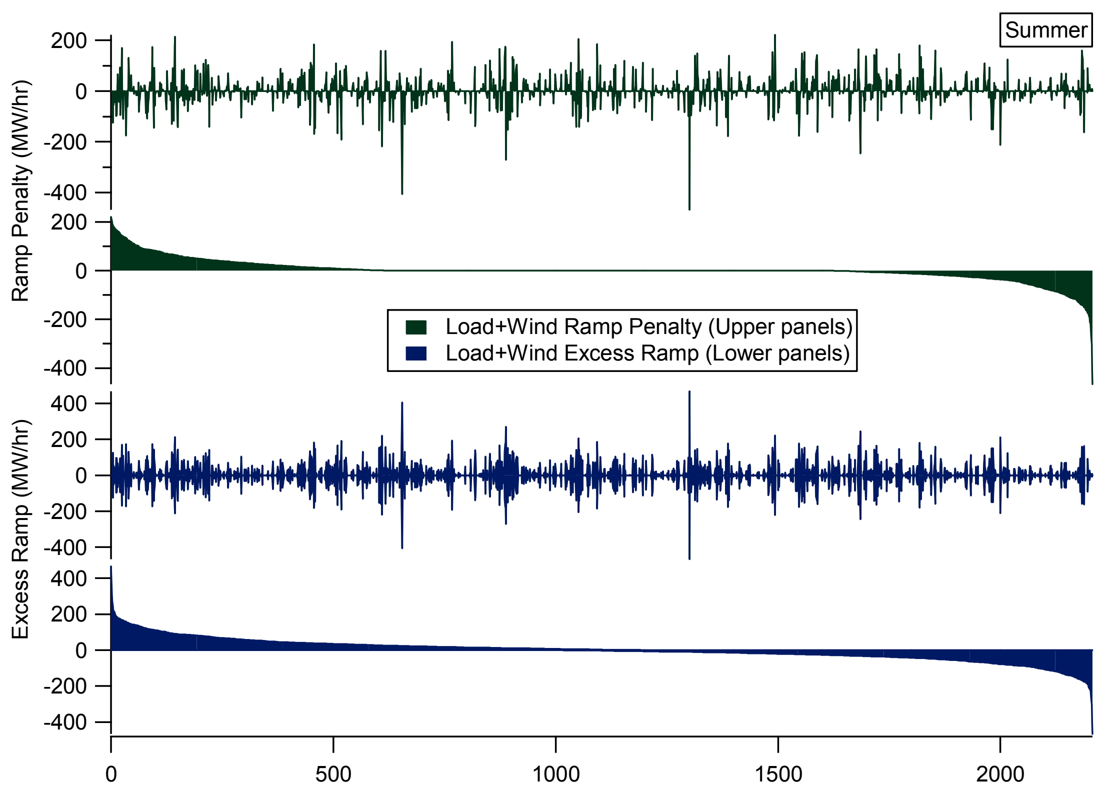

Figure 11. Summer ramp penalty and excess ramp, load and wind.

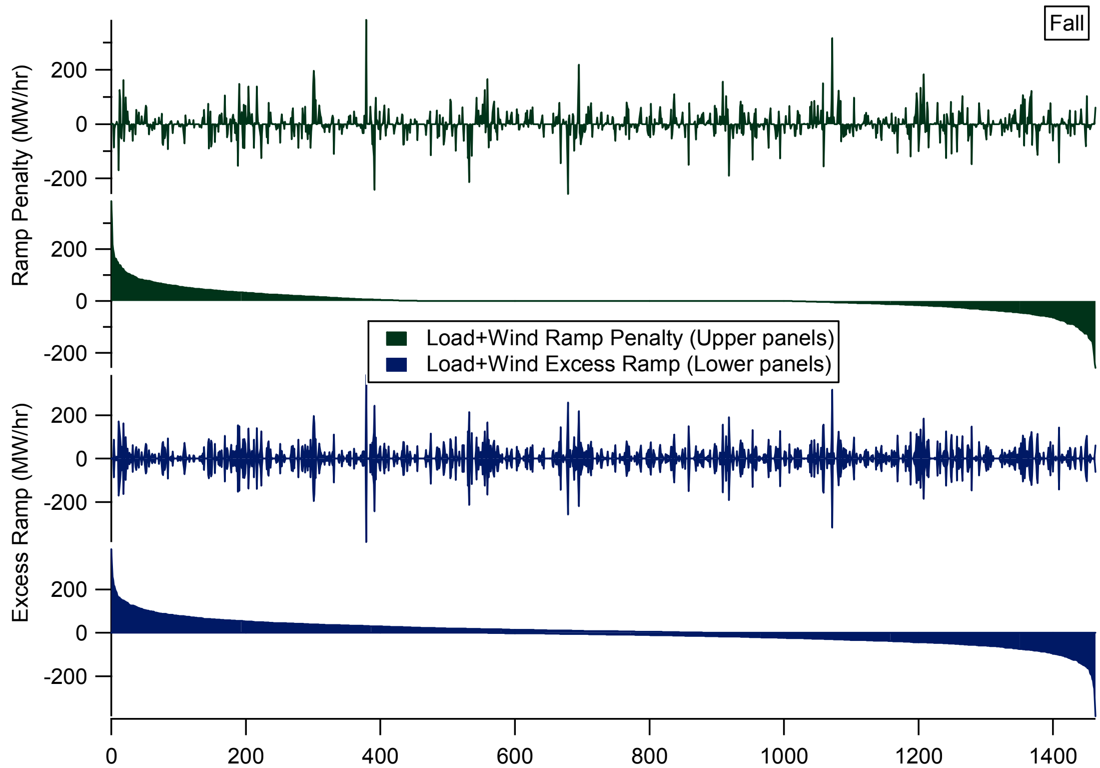

Figure 12. Fall ramp penalty and excess ramp, load and wind

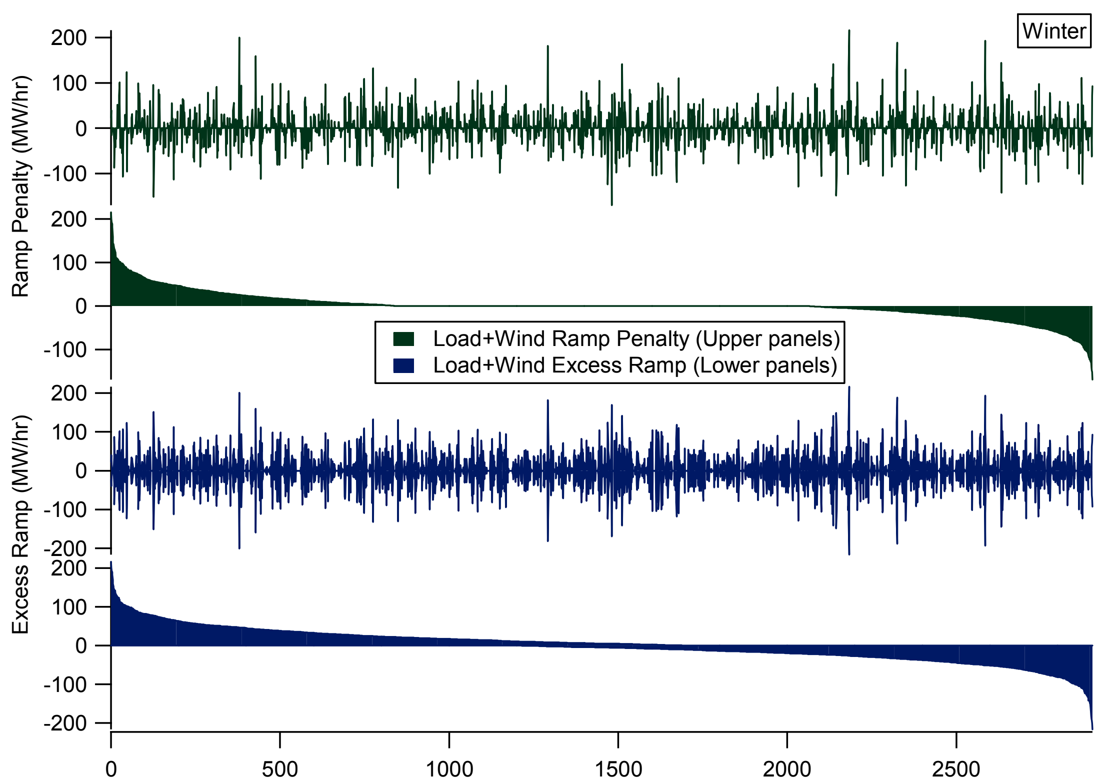

Figure 13. Winter ramp penalty and excess ramp, load and wind.

The tails of the excess ramp duration curves by season indicate a difference in the benefits of consolidation. Maximum excess positive ramps are 467 MW for summer, 367 MW for spring, 384 MW for fall, and 216 MW for winter.

Discussion of the Benefits of Combined Operations

To measure the benefits of combined balancing area operations, it is often useful to use the standard deviation ("sigma") as a metric to describe how variation can be mitigated. One example of this is Miller and Jordon (2006). However, sigma is not appropriate for ramping behavior. To illustrate with a simple example, suppose that a balancing area ramps continuously at 100 MW/hr for a 6-hour period. The standard deviation of this ramp is zero. Alternatively, if 3 ramps were 100 MW/hr, and the other 3 ramps were 0, then the standard deviation would be approximately 55 MW. Clearly, a higher sigma may be associated with *less* ramping, and therefore sigma is not suitable. Alternatively, we can quantify the total up-ramp and down-ramp in terms of MW-hr (not the same as MW/hr), which measures the ramping capacity during the period of interest.

Figure 14 collects results from the previous sections and illustrates the impact of combined balancing area operations on load alone, wind alone, and load with wind. As seen in the more detailed graphs above, combined operation has a more significant impact when there is wind on the system. The maximum hourly ramp for combined system operation with wind is 1,887 MW/hr, which can be compared to the maximum excess ramp of 467 MW/hr. it is clear that combined operations hold the promise of a significant reduction in system ramping requirements.

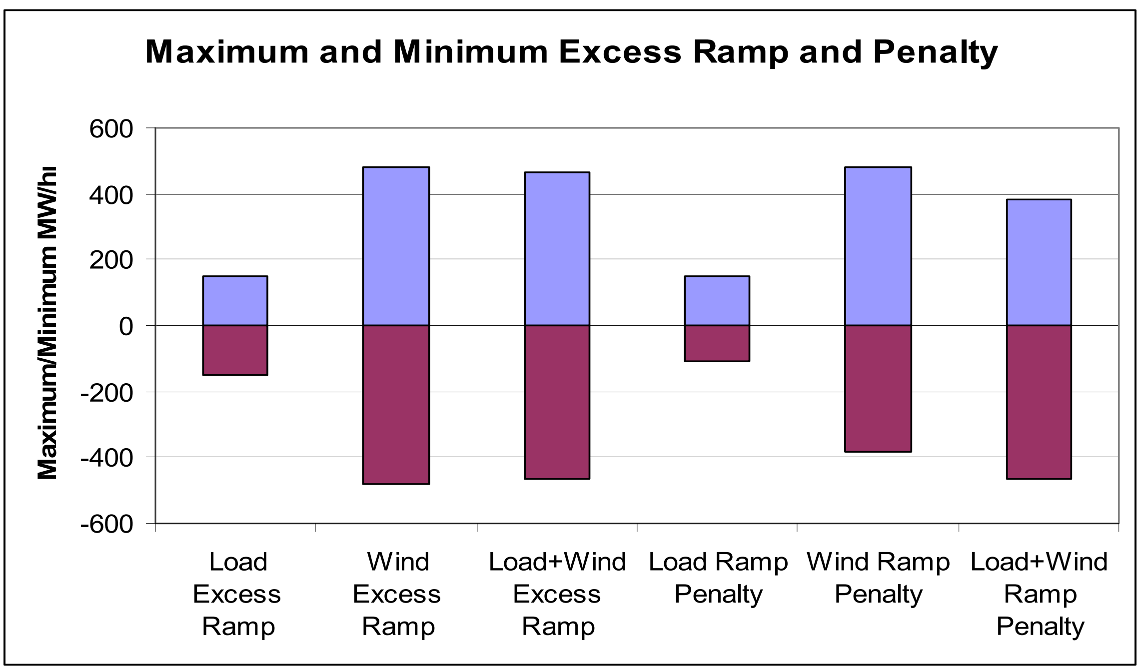

Figure 14. Up-ramp and down-ramp penalty and excess ramp required from separate operations, maximum and minimum.

To get an idea of the benefit over the entire year, Figure 15 shows the total excess ramp and penalty in MW-hr for load alone, wind alone, and load with wind. The graph illustrates a significant reduction in ramping requirements can be achieved by combining operations.

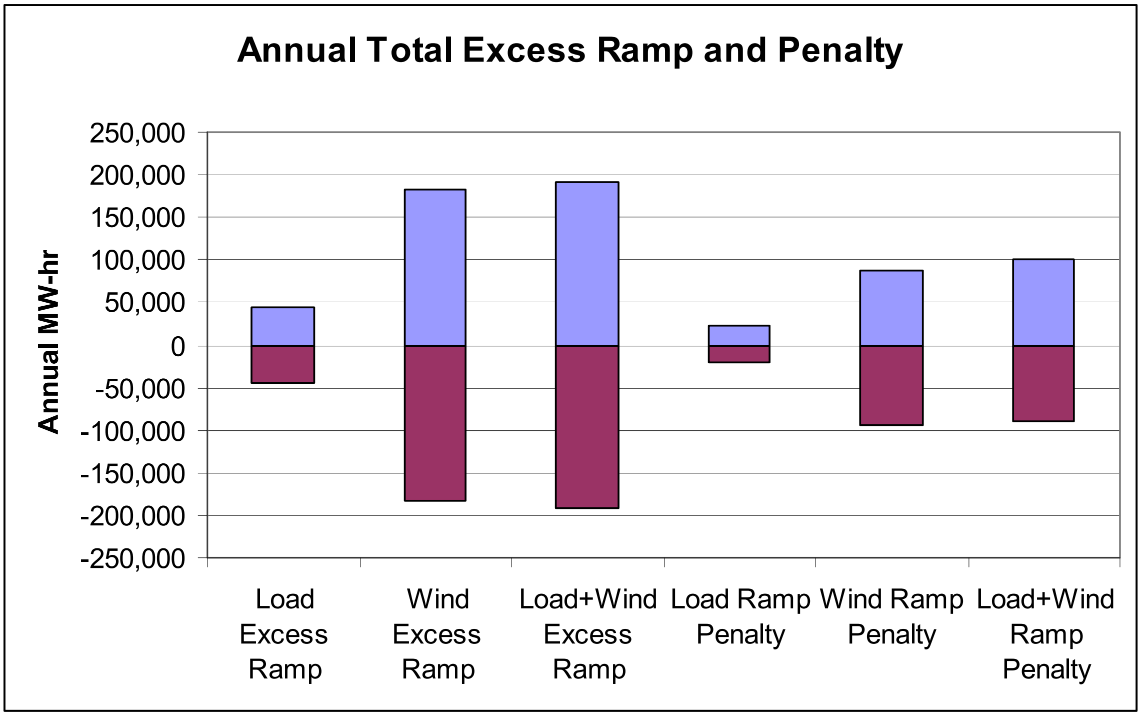

Figure 15. Total excess ramp and penalty from separate operations.

Figure 16 illustrates the ramping penalty by season for the load and wind combined case only. Figure 17 shows the percentage of hours of each season that experience an excess ramp with separate balancing area operations.

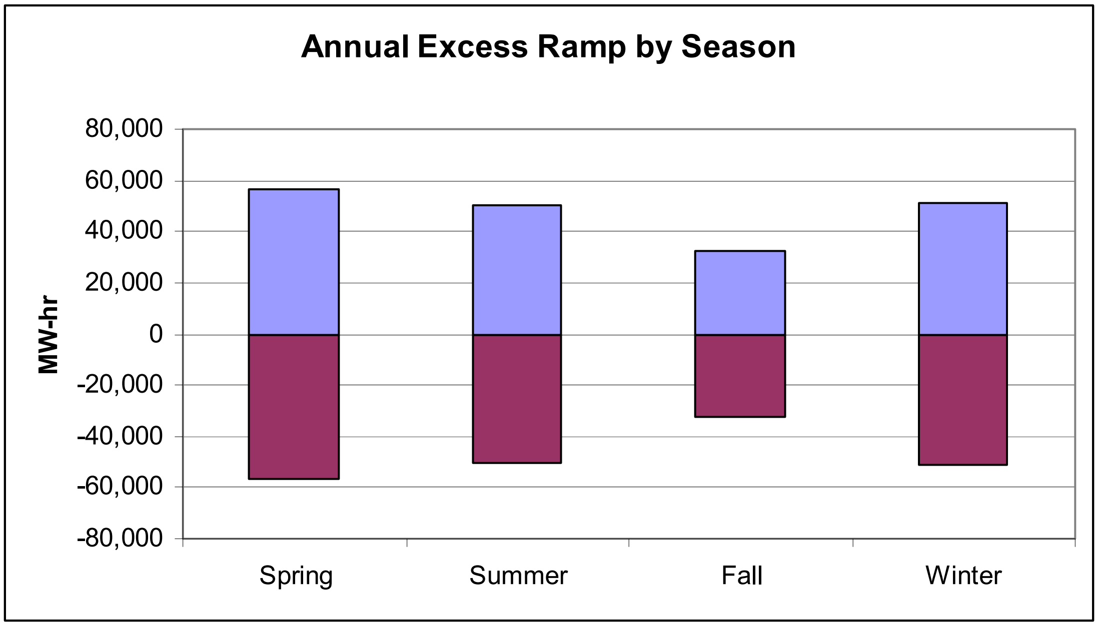

Figure 16. Seasonal excess ramp and penalty for load and wind.

The ramping benefits from combined operation result from events that are not highly correlated. In the hourly time frame, there can be significant correlation among loads that are within the same time zone and that are subject to similar weather effects. It is well known that the correlation between loads will decline over progressively smaller time scales. In the regulation time scale (typically seconds to minutes), loads are generally uncorrelated, which is why regulation impacts tend to add geometrically.

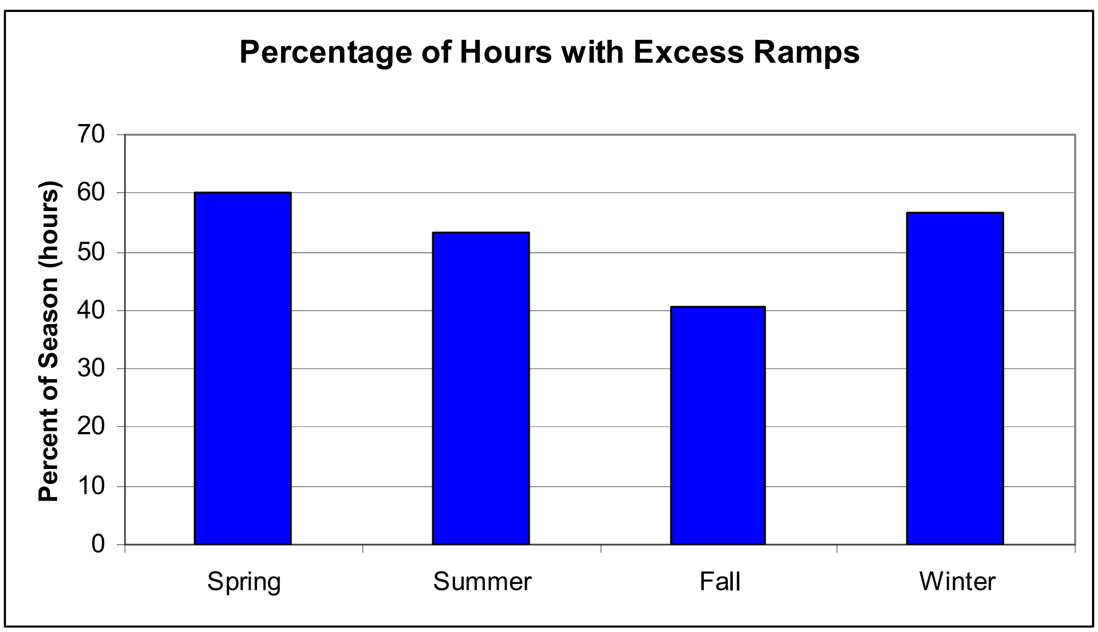

Figure 17. Percentage of hours of each season that experience excess ramping with separate balancing area operations, load and wind.

To obtain a better sense of the excess ramping requirements in the context of overall ramping requirements, Figure 18 shows that the excess ramping is frequently at least 5% of the annual maximum ramp requirements for the combined system. Another way to view the excess ramp is as a percentage of the average up-ramp and down-ramp requirements. The graph shows that in most hours, the excess ramp is less than average, but in a few cases it exceeds 300%, both in the positive and negative directions.

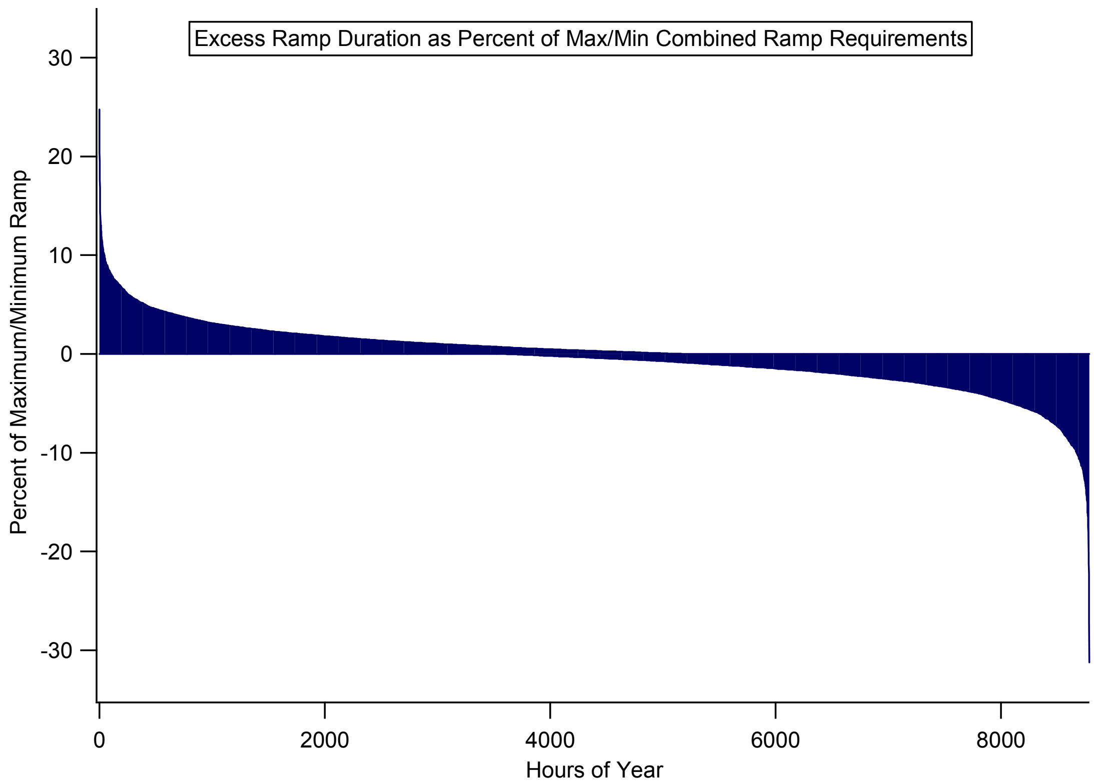

Figure 18. Duration of excess ramp requirements as a percentage of maximum and minimum ramps from combined operation.

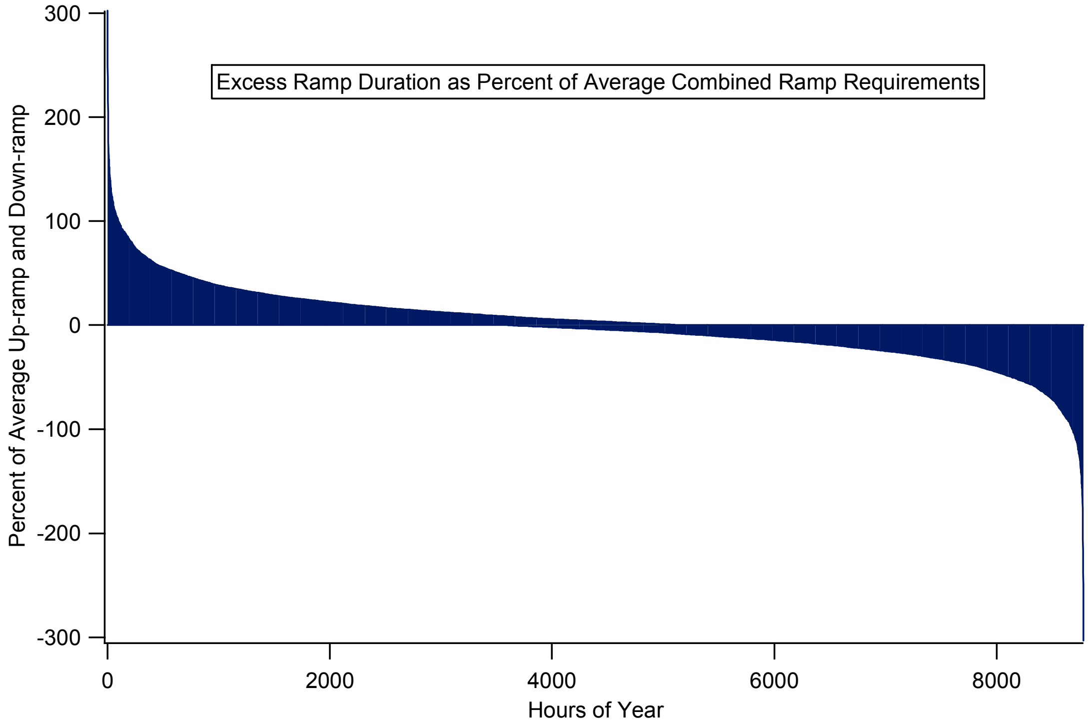

Figure 19. Duration of excess ramp requirements as a percentage of the average up-ramp and down-ramp requirements from combined operations.

Wind generation in the hourly time scale may be correlated if the wind sites are nearby and if there is similar geography and underlying weather impacts. As the distance between wind sites increases, there tends to be less coincident correlation, and there may be more lagged correlation, depending on the wind regimes and weather drivers.

Combining correlated loads or wind will not have as much benefit as combining uncorrelated load or wind. Table 2 shows the cross-correlations between the 14 wind plant locations used in this study. Some wind site pairings have low correlation (approximately 0.21 - 0.40) and others are more highly correlated (for example, wind2 and wind4).

Table 2. Correlation between wind locations.

	wind1	*wind2*	*wind3*	*wind4*	*wind5*	*wind6*	*wind7*	*wind8*	*wind9*	*wind10*	*wind11*	*wind12*	*wind13*	*wind14*
wind1	1													
wind2	0.61	1												
wind3	0.31	0.68	1											
wind4	0.59	0.88	0.62	1										
wind5	0.34	0.68	0.84	0.68	1									
wind6	0.64	0.75	0.54	0.87	0.63	1								
wind7	0.52	0.74	0.63	0.80	0.74	0.85	1							
wind8	0.64	0.64	0.47	0.75	0.55	0.92	0.79	1						
wind9	0.52	0.62	0.50	0.71	0.60	0.83	0.88	0.88	1					
wind10	0.57	0.38	0.25	0.45	0.29	0.60	0.45	0.73	0.59	1				
wind11	0.62	0.46	0.31	0.54	0.36	0.70	0.56	0.83	0.69	0.94	1			
wind12	0.56	0.54	0.39	0.63	0.47	0.78	0.73	0.90	0.89	0.77	0.85	1		
wind13	0.50	0.55	0.43	0.65	0.52	0.78	0.78	0.87	0.95	0.66	0.75	0.94	1	
wind14	0.21	0.48	0.63	0.53	0.73	0.51	0.62	0.45	0.55	0.22	0.28	0.42	0.50	1

Table 3 shows the correlation between the separate balancing areas for loads only. Loads are generally highly correlated in this region, with the exception of MNP's correlation with NSP. The impact of wind on this correlation matrix is seen in Table 4, which shows the correlation between net loads (load minus wind) in the balancing areas. In some cases, wind actually increases the correlation between balancing areas, and in other cases, this correlation decreases with the addition of wind.

Table 3. Correlation between loads.

	NSP	*MNP*	*GRE*	*OTP*
NSP	1			
MNP	0.48	1		
GRE	0.83	0.67	1	
OTP	0.65	0.69	0.85	1

Table 4. Correlation between load with wind.

	NSP	*MNP*	*GRE*	*OTP*
NSP	1			
MNP	0.73	1		
GRE	0.91	0.73	1	
OTP	0.62	0.59	0.57	1

Although we were unable to obtain sub-hourly data for this analysis, we make some observations on the likely impact of aggregation on the intra-hourly balancing requirements and benefits of combined operations. In our analyses of other data sources, and based on the results of wind integration studies, it is apparent that correlation tends to decrease at faster time frames. This implies that combined operations would likely result in more benefits than in the hourly case.

The ramping penalty for separate balancing area operations is a capacity service. This is because the energy requirements from the separate balancing areas add linearly. There is therefore no difference in energy requirements when the separate operations case is compared to the combined case. The ramping penalty represents capacity that must be provided separately by balancing areas, but is not required under the combined case. That this is a capacity service can be verified by integrating the excess ramp and the ramp penalty – the result is zero in both cases.

The analysis in this part of the paper has focused exclusively on the *requirements* for hourly ramping. So far we have not examined the ability of the generation fleet to *provide* ramping. That is a separate question, and is addressed below.

February 24, 2007 – An Interesting Wind Day for ERCOT

February 24, 2007 provides an excellent example of the benefits and limitations of aggregation for wind. Wind production was fairly high throughout ERCOT that morning.

Aggregate wind production was over 2000 MW at 9 a.m.; about 70% of the total 2900 MW state wind capacity. A strong weather pattern increased winds further throughout the western part of the state forcing many wind turbines to shut down as the morning progressed. Individual wind plants can be seen shutting down in Figure 20.

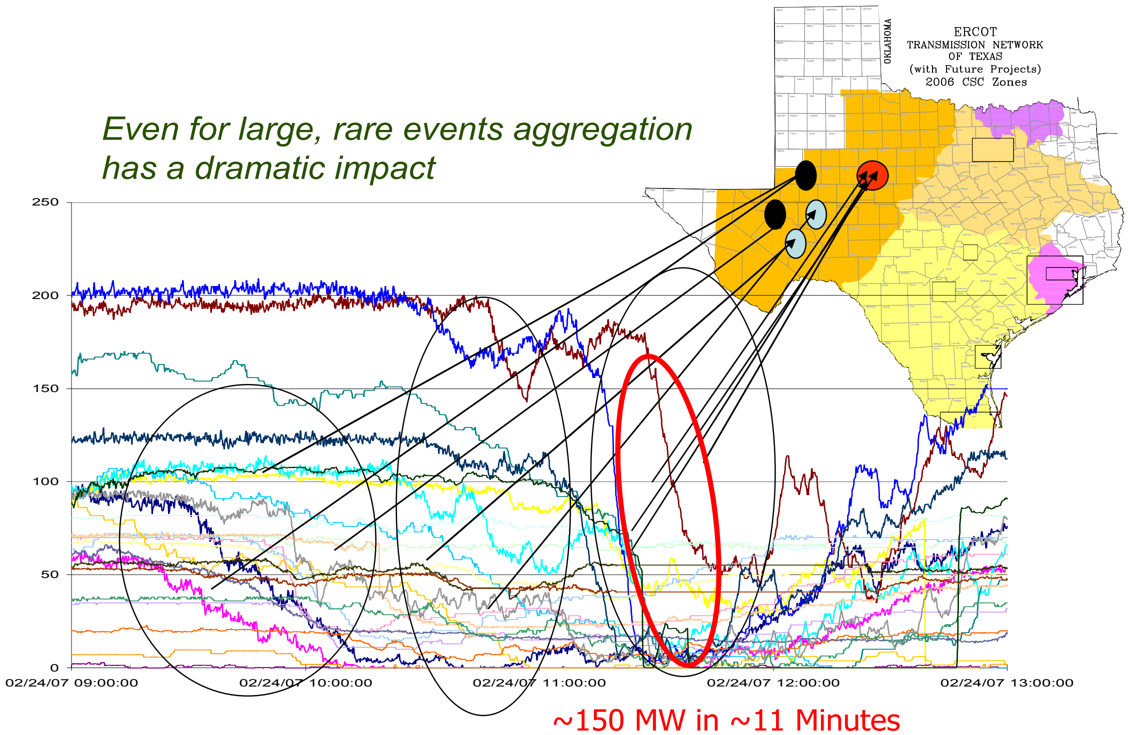

Figure 20. A strong weather pattern increased winds on the morning of February 24, 2007 throughout western Texas, forcing many wind turbines to shut down. Figure supplied by Stuart Nelson.

One 200-MW wind plant dropped 150 MW, 75% of its name plate capacity, in 11 minutes; a fairly dramatic ramping event. Given this single plant behavior, power system planners and operators are legitimately concerned with the possible ramping impact of large amounts of wind on their system. Fortunately aggregation helps.

Clearly this single plant behavior, dropping 75% in 11 minutes, is a much slower than what is exhibited by a single turbine which will drop from full output to zero nearly instantaneously. Looking at the aggregate behavior of all ERCOT wind plants (Figure 21) it can be seen that aggregation continued to slow even the extreme wind event as it is scaled up to cover much of Texas.

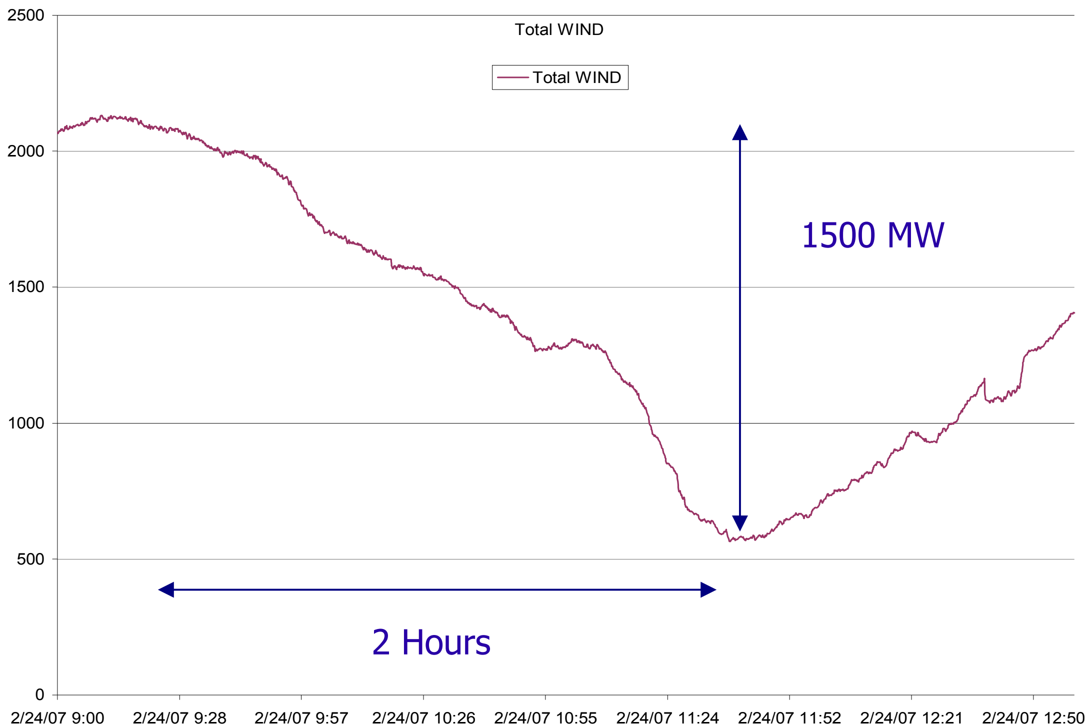

Figure 21. Aggregate wind plant behavior exhibits a slower response.

The total wind fleet dropped ten times as much generation, ~1500 MW, but it took ten times as long, ~120 minutes. This is a dramatic drop in production, to be sure, but it is not extremely fast. It was certainly not a contingency event, and therefore, was not eligible to rely upon contingency reserves. This is a large ramping event

If this event is typical, increasing the size of the wind fleet will increase the size of potential large ramping events, but it will not increase the ramp rate as dramatically. The power system must be capable of responding to the loss of wind, but the resources need not be spinning. Fast-start resources would be adequate to cover infrequent large wind events.

It is also likely that large ramping events like that experienced by ERCOT on 2/24/2007 could be forecast at least some time in advance. Figure 22 shows (to those that can interpret such pictures) a dust cloud caused by high winds moving towards the wind turbine plants. If forecasting tools could give system operators warning that such an event was likely, they might be able to redispatch both the wind and conventional generation fleets to better respond to the wind ramp when it materialized. This would be similar to the way system operators redispatch the power system as lightning approaches or in preparation for geomagnetic storms.

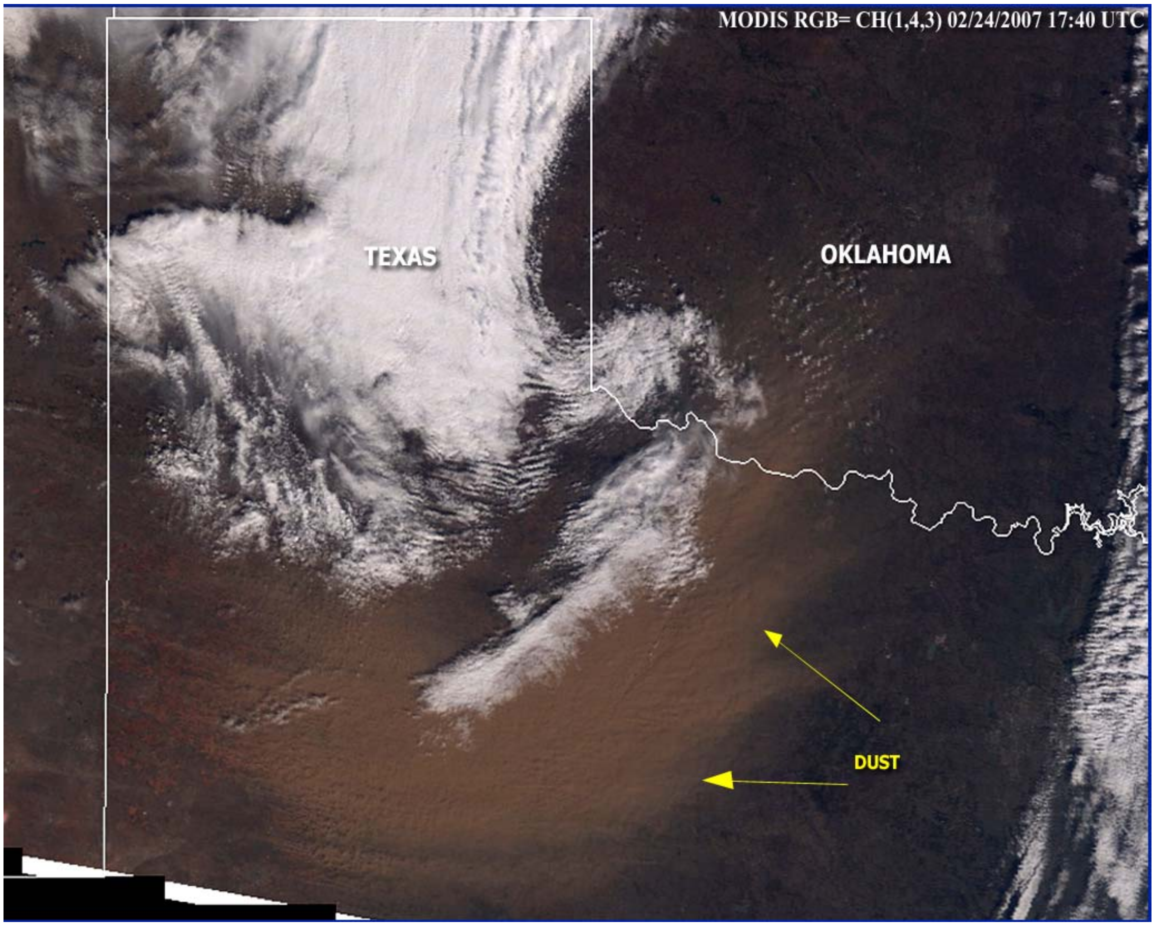

Figure 22. Wind Logics interprets this satellite photograph as showing high winds lofting dust.

Balancing Area Ramping Capability

We have seen how balancing area size influences the ramping requirements of the aggregated wind fleet; geographic diversity greatly reduces the wind ramping impact. We have also seen how aggregating wind with load further reduces the ramping requirements of the aggregation. These are genuine physical reductions in integration requirements. We turn now to briefly look at the supply of ramping capability. The work offered here extends previous work we presented at WindPower 2005 and 2006 (Kirby and Milligan, 2005 and 2006) where we introduced a method for determining a balancing authority's ramping capability for every hour of the year. We also discussed how ramping can be either a very low-cost byproduct of fast energy markets, or it can be a very expensive additional service, depending on the characteristics of the balancing area's generation fleet.

Ramping: Low-Cost Energy Market Byproduct or Expensive Service?

We are going to argue that in many cases there is an abundance of ramping capability inherently available from the conventional generation fleet. Market rules may or may not provide access to that capability, but it is physically there. This can be quantified on an hourly basis for any given balancing authority. Why ramping (or load following) is often essentially free can be seen through the example presented in Figure 23. This typical daily load curve shows four classes of generators serving the load. Nearly 20,000 MW can be served from the lowest cost baseload generators that can run continuously and need no maneuvering capability to meet their energy obligations.

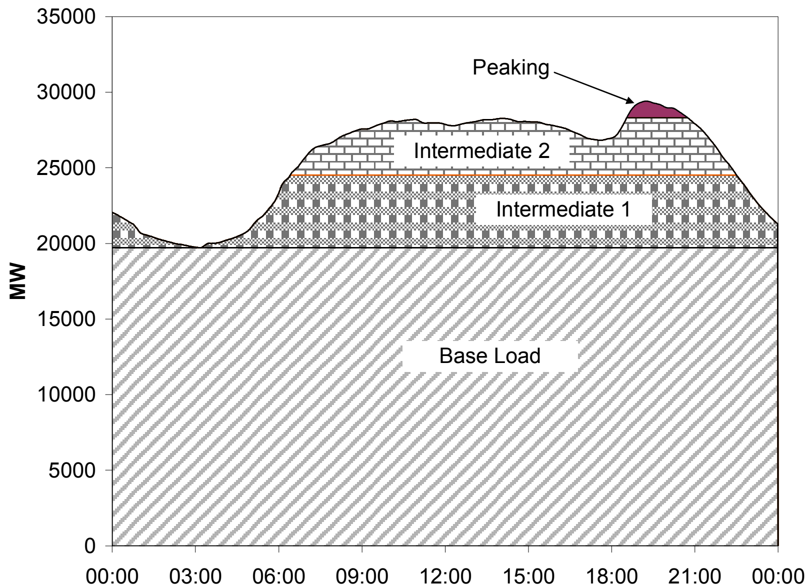

Figure 23. Participation in energy markets requires maneuverability for all but base load units.

The remaining generators (Intermediate 1, Intermediate 2, and Peaking) must have maneuvering capability simply to be in the energy market. Their output is not needed all day, so they must have the ability to cycle on and off in order to sell into the hourly energy market. If they could not cycle or follow load, they would not be selected to supply energy at all. They would have to compete with the baseload generators that do not cycle, but which have lower costs. These last generators must be flexible concerning their output levels and run times, not because of load following requirements, but simply to be able to sell energy into a variable market. Flexibility would be needed even if the load was known in advance (it is still different from day to day). Flexibility would be needed even if the load made perfect step changes hourly (both run time and level would still vary). Inflexible units such as nuclear plants simply could not serve this part of the load or sell energy into this market.

When a utility or an IPP considers building a generator, it has to decide which part of the market it wishes to serve. If it wants to serve the baseload market, it will build a generator with low operating cost so that it is always on. It will have high efficiency and low fuel costs. Capital cost can be higher because the cost is spread over many hours. The generator need not have much maneuvering capability. If the utility or IPP decides it can't compete with existing baseload generators, and wants to serve the intermediate or peaking market instead, the generator will have to be lower capital cost because there are fewer hours to spread that cost over. It can have a lower efficiency or a higher fuel cost because power prices will be higher. It must be maneuverable to be able to enter and leave the energy market as prices rise and fall with rising and falling load.

The basic question of whether we need a ramping service or just fast energy markets can be looked at somewhat differently now. Do the generators that are built to meet the intermediate and peaking energy markets (higher operating cost, lower capital cost) inherently have enough response capability to meet the system's ramping needs? If so, there is little point in creating or paying for a ramping service, or dispatching specific generators to provide it. Integrating wind generation, with its increased ramping requirements, may not be too expensive.

First we will examine the opposite case. What if the marginal generators do not have sufficient ramping capability? Figure 24 presents a hypothetical example where a fast energy market, which normally provides load following as a byproduct, may have

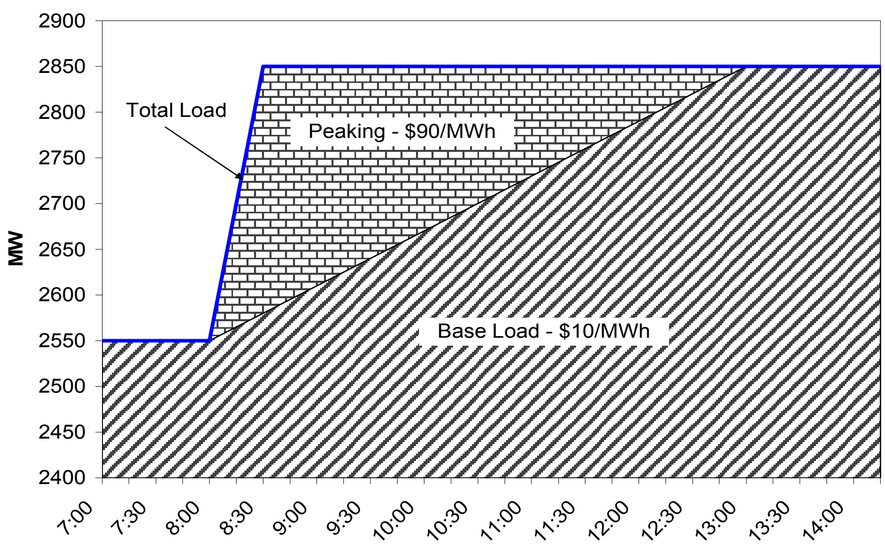

Figure 24. In this simple example load following is required from an expensive peaking generator but energy is only an incidental product.

difficulty providing ramp capacity under some conditions. Prior to 8:00 a.m., this example system is serving the 2,550 MW load with over 3,000 MW of base-load generation and therefore clearing all energy at $10/MWh. At 8:00 a.m., a 300 MW ramp starts which the base load generation can not follow. There is ample base load capacity; it simply can not ramp fast enough. Peaking generation (the only other generation in this example system) is started to meet the ramp needs. The peak generator stays on until the base load generation can ramp up. With no explicit ramping service, the price rises for the *entire* energy market (all 2,850 MW) from $10/MWh to $90/MWh for 5 hours just to follow a 30-minute 300-MW ramp. In this case, it might be better to create a separate ramping or load following service and pay the peak generator for its response, rather than distorting the price of the entire energy market.

It is very important to determine if ramping requirements can be served at a low cost as a byproduct of the sub-hourly energy market, or if ramping requirements impose a high cost because dedicated resources must be used. Wind integration studies that *assume* the need for dedicated ramping resources will calculate much higher integration costs than ones that tap actual system ramping capability. We analyzed demonstrated thermal ramping capability from a public database and compared it to the system balancing requirements for alternative balancing area configurations.

Individual Generator and Fleet Ramping Capability in Minnesota

We used the method we first developed in 2005 to determine individual thermal generator and aggregate ramping capability that was available each hour of the analysis year.[2] Because generator ramping capability is not publicly available, we derived both the unit capability and the hourly availability from hourly public generator output data. For each generator, we analyzed a year of hourly generator output data to determine the maximum output, minimum non-zero operating output, and MW/min ramping capability. We were careful to avoid hours immediately before or after startup or shutdown, when false ramp rates and minimum loads are in the data. These estimates of generator capability are conservative. They only consider capability that was used during the year, and they can not detect faster ramp rates that are not sustained for a full hour. Only thermal generators are considered, so ramping capability from hydro is ignored. Generators that are located outside of the four control areas were also not considered. Individual generator capabilities were summed each hour to determine the total balancing area thermal fleet capability.

Figure 25 presents a histogram of the fleet ramping capability compared with the ramping requirements of the load, and the load aggregated with wind generation. Two things are immediately obvious. First, thermal ramping capability generally greatly exceeds load and wind requirements. Second, load and wind up and down ramping requirements are largely symmetric, but the generator ramping capability is not. There is much more down ramp capability than up ramp capability. This is not surprising. Most generators tend to get dispatched near full load so they have more capability to move down than up in normal operations.

The daily pattern of thermal generating fleet ramping-capability is shown in Figure 26. The daily load shape is perceptible, but it does not dominate. That is, average up ramp capability is greater during the night than during the day, but it never approaches zero.

[2] Hourly generator output data is published as an EPA requirement. It is only available for fossil-fuel burning generators.

Down ramping capability is always large. The thermal generation fleet always has the capability to respond to nearly 3,000 MW/hour of wind increase.

Implications for Wind Integration

Thermal units in this system have ample ramping capacity to accommodate load and wind for the vast majority of hours. This does not disagree with operator recollections of specific instances when wind ramping caused problems. Instead, it suggests that ramping is not normally an economic problem. The lack of symmetry indicates that wind up-ramps are much less of a concern than wind down ramps. Of course, if the wind is already blowing, it has freed up generating capacity that is in theory available if the wind stops. This does not guarantee that there will be sufficient ramping capability, or that the generation is even on line and available to respond.

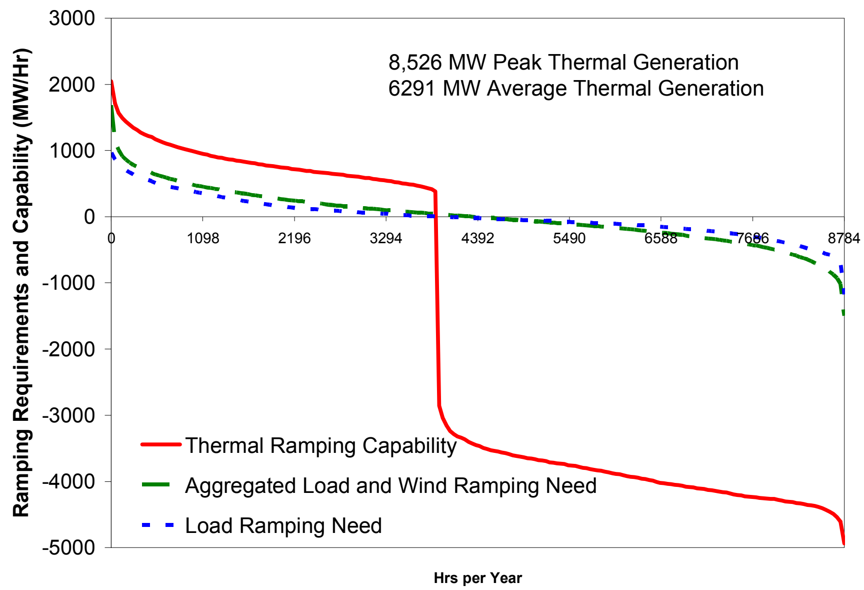

Figure 25. Thermal ramping capabilities exceed load and wind ramping requirements.

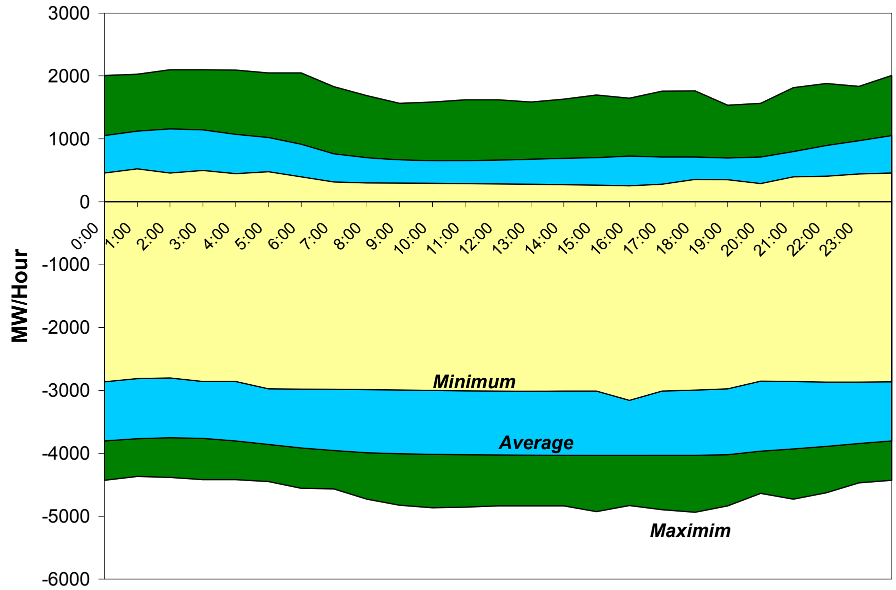

Figure 26. Hourly system ramping capability reflects the daily load pattern, but the daily pattern does not dominate. The plot reflects a full year of hourly data.

Access to the sub-hourly ramping capability of the generators that are in the energy market is critical. Market structures that artificially limit generator movement artificially deny the system a vital reliability resource, and force the expensive procurement of alternative maneuverability. This greatly increases wind integration costs and provides no benefits. Though available generator ramping capability adds linearly as larger groups are aggregated together, the load and wind ramping requirements do not. Consequently, the probability that excess ramping capacity is available increases as the balancing region increases in size. This can be accomplished by combining Balancing Areas or by facilitating sub-hourly transactions between individual Balancing Areas.

Physical access to the generation is critical as well. Transmission constraints complicate the situation by subdividing the generation pool and disaggregating the ramping resource. We made no attempt in this analysis to account for transmission constraints.

Obtaining Load Following From Real-Time Energy Markets: ERCOT and NYISO

The fact that excess ramping capability exists within the generation fleet does not itself guarantee that generators are willing to maneuver without significant compensation. An examination of sub-hourly energy markets shows that the energy markets themselves do provide such an incentive, and they do it without incurring costs to customers. ERCOT, PJM, NYISO, ISONE, MISO, and CAISO all operate sub-hourly energy markets which are capable of responding to wind variability and forecast error. We examined a year of sub-hourly price data from both ERCOT and NYISO.

Examination of price data from the ERCOT 15-minute real-time market provides insights into how load following can be extracted from sub-hourly energy markets at little or no cost. ERCOT 15-minute real-time energy market price-data was examined for all of 2006 to determine if there is a cost associated with obtaining sub-hourly response from generators. Clearly, obtaining minute-to-minute response is costly since regulation is always the most expensive ancillary service, with prices that remain high even at night. Presumably, then, 15-minute response would be more expensive than hourly response. ERCOT data provides some surprising results. [3]

Regulation markets specifically procure maneuvering capacity from generators. When a generator sells a MW of capacity to the regulation market for an hour the generator gives the system operator the right to move the generator's real-power output anywhere within the sold range in whatever manner the system operator desires. Generators participating in sub hourly energy markets, on the other hand, do not sell control; they simply respond to energy price signals. Further, prices seldom got to zero or negative. This means that a generator's response incentive in any given sub-hourly interval depends on the generator's production cost; some generators will have an incentive to respond, and others will not. Any are free to maintain a constant output and accept the hourly average price if their maneuvering cost is too high. Studying a year of 15-minute price data, we found that the ERCOT 15-minute market provides a significant response incentive with the high and low prices for each interval in the hour differing by $13.64/MWh on average. The market is continuously sending the 15-minute market a strong price signal to move up or down.

Figure 27 presents a simplified one hour example. Market prices are shown in the upper part of the graph. The 15-minute market price varies every interval between $55/MWh and $75/MWh. Clearly, any generator with a production cost below $55/MWh will provide full output continuously, and will have no incentive to maneuver because it is making a profit during every interval.

Things are more interesting for a generator with a production cost above $55/MWh. The lower portion of Figure 27 shows the profit that a generator with a $60/MWh production cost would receive from the two behaviors in the market. The generator would earn a $5/MWh profit if it maintained a constant output ($65/MWh average price - $60/MWh production cost). It would earn $7.50/MWh profit ($75/MWh price - $60/MWh production cost = $15/MWh profit for half of the time and $0/MWh for the other half of the time), $2.50/MWh more, if it responded to the 15-minute price signal and curtailed production during the intervals that the price was below its production cost (we have a *very* flexible generator in this simplified illustrative example).

[3] Price data is from ERCOT North region, but similar results were obtained from other ERCOT regions.

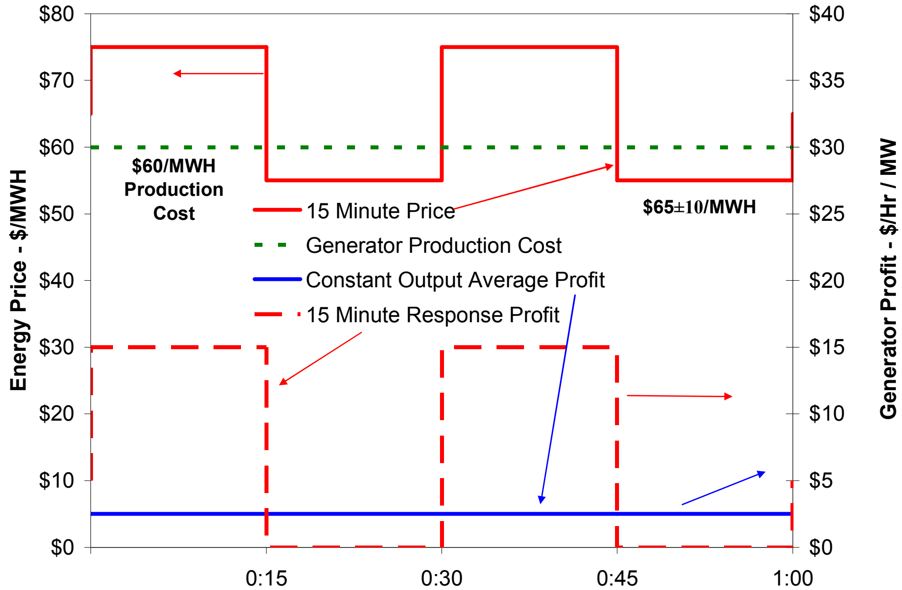

Figure 27. A simplified one-hour example shows there is an incentive for some generators to respond to 15-minute price signals.

The 15-minute market provides an economic incentive for generators with marginal costs that are close to the market clearing price to respond. Figure 28 shows how the incentive to respond (green solid curve) changes as a function of generator production cost, peaking when the production cost is equal to the market prices. Note that while the incentive to respond rises as generator production cost rises, the actual profit the generator receives for either behavior declines (blue dashed and red dotted curves).

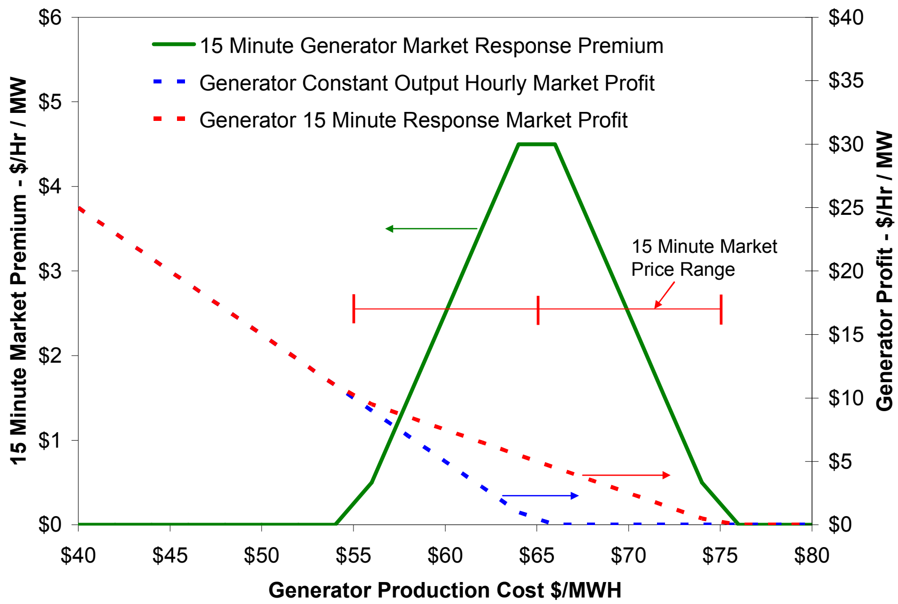

Figure 28. The sub-hourly response incentive is a function of the generator's marginal production cost.

Figure 29 presents results from examining potential generator profits from responding to the actual ERCOT 15-minute price signals vs. providing constant output throughout the hour for all of 2006. The incentive to respond is higher for high-cost generators, both in absolute dollars and as a percentage of their total profit.

NYISO

The NYISO market structure adds an interesting complication; NYISO operates both 5-minute and hourly real-time markets:

- $55.51/MWh average day-ahead hourly price[4]
- $52.01/MWh average real-time 5-minute price
- $3.50/MWh average fast-market participation penalty[5]

The average energy price for all of 2006 was $3.50/MWh *higher* in the day-ahead hourly market than in the 5-minute real-time market. This price difference reflects the difference in value of day-ahead commitment vs. the real-time transaction as well as any difference associated with the faster 5-minute response. This appears to say that there is no overall cost to the power system associated with obtaining 5-minute response from generators; in fact, the faster market clears at a lower price on average.

[4] Price data is for NYISO 2006 reference bus. Actual locations incur costs (or payments) for losses and congestion. Examining locational prices in the 11 NYISO zones produced similar results.
[5] This price difference also reflects the difference in value of day-ahead commitment vs. the real-time transaction.

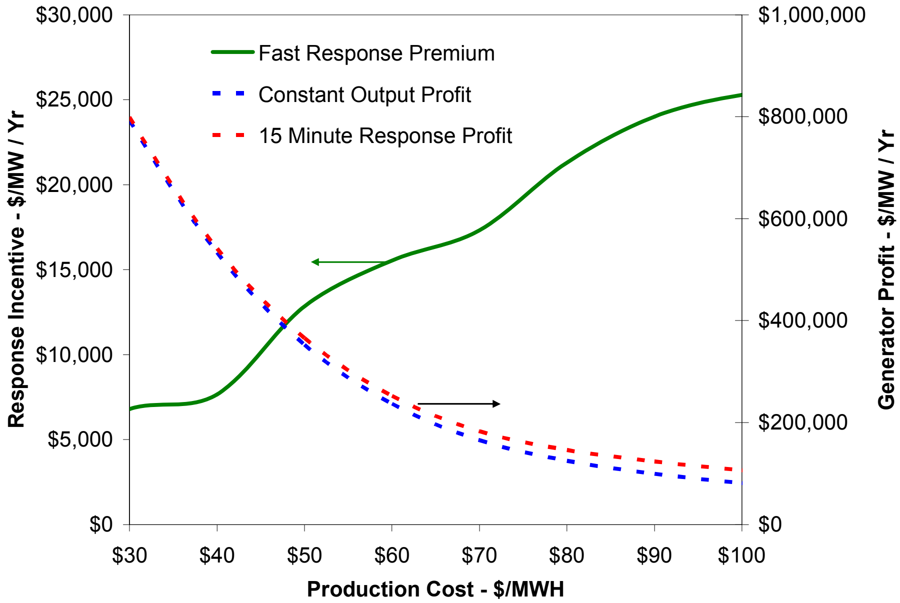

Figure 29. Price data from the 2006 ERCOT 15-minute market shows that a generator's incentive to respond increases as the generator's production cost increases.

Given that the hourly market yields a higher average price than the 5-minute market, and given that any unit capable of responding to the 5-minute market is capable of responding to the hourly market (but the opposite is not necessarily true), one wonders why any generator would choose to participate in the 5-minute market instead of the hourly market? One answer lies in a more detailed look at the two markets.

While the annual average prices for the two markets are fairly close, prices during individual 5-minute intervals differ significantly (the same effect explored with the ERCOT data). The annual average of the price difference *absolute value* during each 5-minute interval is $17.41/MWh. The NYISO market is continuously sending the 5-minute market a very strong price signal to move up or down with respect to the hourly market.

Figure 30 presents a simplified example for the NYISO market which is similar to the ERCOT example. The difference is that the NYISO market still provides a response incentive even though the hourly price is higher than the average 5-minute price. Figure 31 shows that the response incentive is negative for generators with a production cost below $48, but is positive for higher cost generators. Finally, Figure 32 presents the incentive results for the full year. A generator with a production cost above about $40/MWh[6] has an incentive to respond to the 5-minute market price signals. Of course, any actual generator will move between the two markets throughout the year as price signals dictate.

[6] The price where the response incentive starts is higher at locations with losses and congestion costs, but the concept is the same.

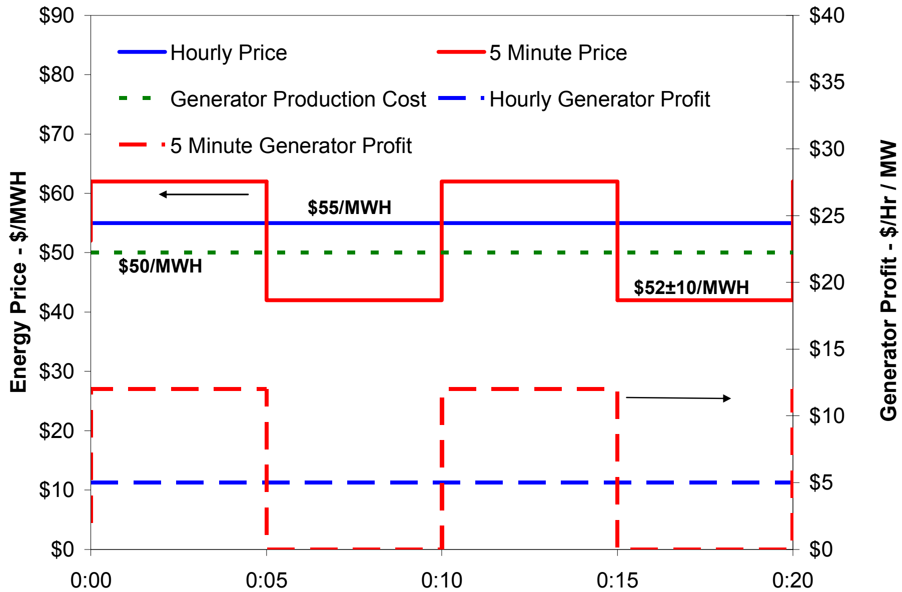

Figure 30. A simplified one-hour example shows there is an incentive for some generators to respond to 5-minute price signals.

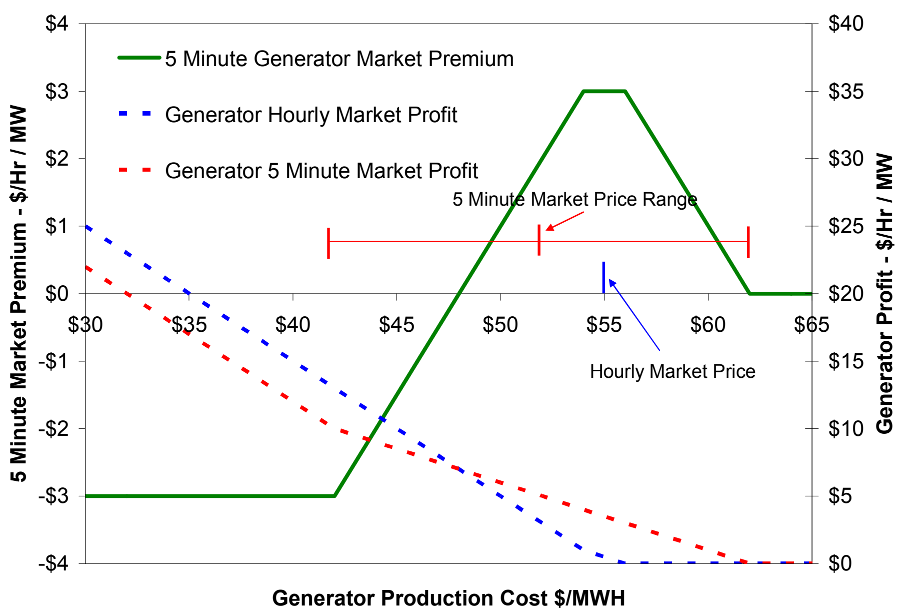

Figure 31. The sub-hourly response incentive is a function of the generator's marginal production cost.

The net result is that regions that operate sub-hourly energy markets inherently provide economic incentives to specific generators to voluntarily provide intra-hour response and they can do this at no added cost. While minute-to-minute regulation is inherently an expensive ancillary service, intra-hour load following need not be.

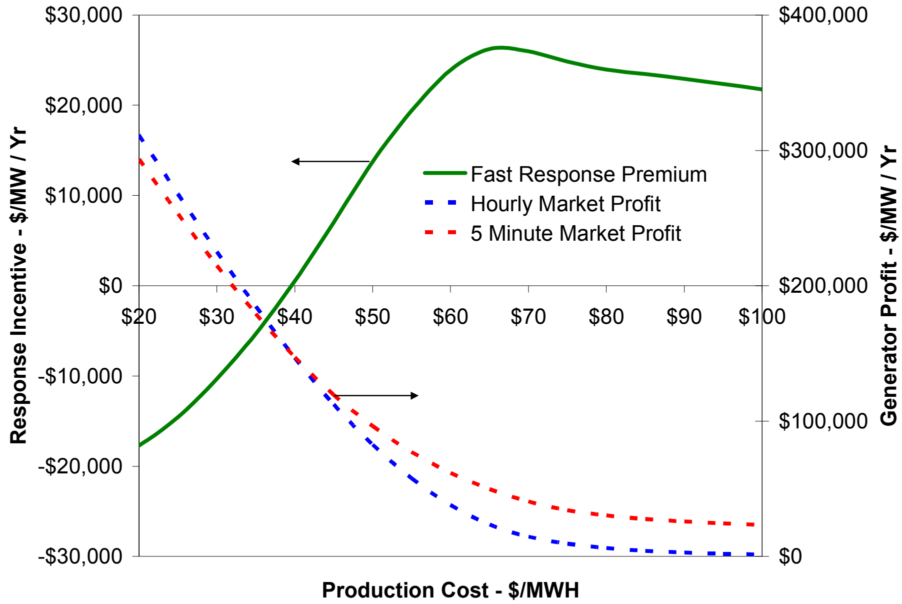

Figure 32. Price data from NYISO 5-minute and hourly 2006 markets shows that generators with production costs around $40/MWh have an ncentive to respond.

Forecasting Errors, Ramping Requirements and Unit Commitment

The unit commitment process is the multi-day equivalent of the hourly and sub-hourly economic dispatch. It assesses system requirements at least a day ahead (longer for generators with long startup times) to determine the least-cost mix of generation to have available for each interval of the next several days. This is necessary because some generators require significant time to start up. It is also necessary to consider the inter-temporal constraints so that the least-cost, on-peak generation mix is also able to economically turn down far enough to operate during off-peak hours. Selecting generators for the least-cost energy supply is the primary consideration, but the unit commitment process must also assure that the selected mix has enough ramping capability to meet the aggregated balancing area's needs each hour.

Forecasting error is important as well. A unit commitment that precisely matched tomorrows' expected conditions might prove to be an expensive mistake if the load was a few percent higher and not enough cheap generation was made available. It can also be expensive to over-commit generation that is not needed. The optimal unit commitment process must consider a range of future conditions and select a robust solution.

Adding wind to the balancing area complicates the unit commitment process. Energy requirements, ramping requirements, and forecast error amounts all change. A robust unit commitment solution is even more important to deal with the greater uncertainty. In calculating the increased unit commitment cost it is important to correctly select the base case. The base case must include the load uncertainty for the comparison to be valid. Wind and load forecast errors will not add linearly. Evidence from the Minnesota 20% Wind study shows that wind forecast errors from four sites are generally uncorrelated on an hourly basis. The aggregate forecast error is reduced by 38% for the combined sites, as compared to individual sites.

The unit commitment problem is numerically more complex in a large balancing area because of the larger number of generators, but the economic commitment solutions are more robust, less volatile, and lower cost. This is because each individual generator is a smaller percentage of the total system requirements. This gives the unit commitment algorithm more flexibility in achieving a finer resolution solution. Load and wind forecasts are more accurate for larger balancing areas as well. Recent information from Germany characterizes the RMS wind day-ahead forecast errors as follows: single wind farm 10% - 20%, Single Control Area (250 square miles) 7.5% - 10%, and all control areas in Germany (400 x 500 miles) 5% - 6.5%.

Relevance to Wind Integration Studies and Implication for High Wind Penetration

Several wind integration studies have been done in the U.S. during the past few years. These analyses focus on the physical requirements of wind integration, and generally also calculate the wind integration cost based on these requirements. Table 5 shows some results from recent studies (Smith et. al., 2007). Of the integration studies in Table 5, all but one study finds that load following costs are very low. That one is from a region that does not have sub-hourly energy markets.

In two studies of California (Shiu, 2006 and Miller et. al 2007), load following cost was estimated to be approximately zero because of the depth of the dispatch stack. California has a robust energy market which runs every five minutes. The analyses concluded that this market provides sufficient flexibility to provide load following services, and by implication, ramping, because of the fast energy market and large resource stack. As our analysis has shown, fast energy markets can often provide sufficient ramping capability at little or no cost. When the currently running resource mix does not have the ability to ramp quickly enough, a high-cost quick-start unit may be necessary, and this can set the energy price in the market.

Table 5. Wind Integration Results

Date	Study	Wind Capacity Penetration (%)	Regulation Cost ($/MWh)	Load Following Cost ($/MWh)	Unit Commitment Cost ($/MWh)	Gas Supply Cost ($/MWh)	Total Operating Cost Impact ($/MWh)
May '03	Xcel-UWIG	3.5	0	0.41	1.44	na	1.85
Sep '04	Xcel-MNDOC	15	0.23	na	4.37	na	4.60
June '06	CA RPS Multi-year	4	0.45*	trace	na	na	0.45
Feb '07	GE/Pier/CAIAP	20	0-0.69	trace	na***	na	0-0.69***
June '03	We Energies	4	1.12	0.09	0.69	na	1.90
June '03	We Energies	29	1.02	0.15	1.75	na	2.92
2005	PacifiCorp	20	0	1.6	3.0	na	4.60
April '06	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
April '06	Xcel-PSCo	15	0.20	na	3.32	1.45	4.97
Dec '06	MN 20%	31**					4.41**

* 3-year average; total is non-market cost
** highest integration cost of 3 years; 30.7% capacity penetration corresponding to 25% energy penetration; 24.7% capacity penetration at 20% energy penetration
*** found $4.37/MWh reduction in UC cost when wind forecasting is used in UC decision

It is widely accepted that the wind integration cost will generally increase with wind penetration. Existing studies have shown that to be true, as indicated in Table 5. There has been additional speculation that "at some point," integrating larger wind penetrations will be difficult and costly. This hypothesis is sometimes known as the hockey stick hypothesis, and says that wind integration cost will increase sharply at some critical penetration rate.

Few, if any, integration studies have successfully identified this point of sharply increased integration cost at penetrations studied so far. In this paper, we have demonstrated that this potential high integration cost could occur if the least-cost energy-producing generators did not have enough ramping capability to meet the aggregate system needs. In that case, faster responding, more expensive generation would have to be brought on line. If this happened very many hours each year, it could be very expensive as it would raise the market clearing price of energy for all buyers and sellers. This could occur if there was not enough physical ramping capability in the energy market generation fleet, or if the market structure did not allow generators to respond to sub-hourly energy market signals.

At the same time, we have shown that ramping requirements can be reduced by balancing area consolidation. Because markets appear to have the ability of bringing out supply response in sub-hourly energy markets, and because existing thermal resources appear to have significant untapped ramping capability, we believe that a combination of fast energy markets and combined Balancing Area operations can increase the grid's ability to absorb higher wind penetrations without experiencing significant operational problems or costs.

Conclusions

Increasing the size of balancing areas, or collectively sharing the balancing obligation among a group of balancing areas (much as is done now for contingency events with reserve sharing groups), holds the promise of significantly reducing wind integration costs. It also reduces utility costs without wind. Some recent studies of integrating wind into large power systems seem to indicate that wind integration costs may rise more smoothly than previously assumed, based on analysis of smaller power systems. The "hockey stick" pattern of dramatically increasing wind integration cost above some threshold wind penetration may not be as pronounced as expected. This paper provides some explanation as to why costs may rise more uniformly than previously assumed.

We have shown that ramping requirements can be reduced by balancing area consolidation. Because markets appear to have the ability of bringing out supply response in sub-hourly energy markets, and because existing thermal resources appear to have significant untapped ramping capability, we believe that a combination of fast energy markets and combined balancing area operations can increase the grid's ability to absorb higher wind penetrations without experiencing significant operational problems or costs.

Based on the hourly data used for this analysis, we showed that balancing area consolidation will reduce the ramping requirements for load, wind, and load with wind. Our results show that the ramping penalty associated with operating independent balancing areas increases significantly when there is significant wind on the system, particularly with the extremely high penetration represented by our data set. Because of the declining correlation between wind and load for faster time frames, the aggregation benefit is expected to increase for faster load following time frames. This can be verified by reviewing results from wind integration studies that evaluate the regulation time frame, and is supported by Miller & Jordan's analysis of the NYISO system.

Balancing areas that operate sub-hourly markets can obtain ramping capability from the generators supplying energy at little or no cost. The critical questions are: does the on-line generating fleet have sufficient physical maneuvering capability and does the market structure provide access to it? Sub-hourly energy markets provide economic incentives for generators to respond when needed. Insufficient ramping capability will manifest itself as a need to dispatch generators out of economic merit order and may (depending on the market rules) increase the market clearing price of energy. Market monitors will be able to determine if this is happening so that it can be remedied. One remedy would be to initiate a specific load following or ramping service, similar to regulation, but over a longer time frame. To date, no balancing area that we are aware of has initiated a load following service.

Our study of both the ERCOT and NYISO sub-hourly energy markets shows that these markets provide strong economic signals to the marginal units to provide ramping response without increasing the average cost of energy. Individual generators are free to respond or to accept the average price and hold a flat hourly output, whichever is more economic for their operation. They can increase their profit considerably, however, if they are able to follow the fast energy price signals.

Generator ramping capability data is not publicly available, but a conservative estimate of that capability can be deduced from hourly energy reports. Examining the output of all thermal generators in Minnesota for a year allowed us to calculate each unit's demonstrated hourly ramping capability, as well as the excess ramping capability that was on line for each hour of the year. The thermal fleet always has dramatically more downward ramping capability than the aggregate system requires. This is not surprising because thermal generators are typically dispatched near full load. This means that the fleet has ample ramping capacity to accommodate unexpected increases in wind generation as long as there is no transmission congestion that blocks access.

The thermal generation fleet also has significant up-ramp capability, generally, over two times what is required for both load and wind. Of course, adding wind to the system displaces thermal generation and frees up that generation to respond to drops in wind as long as the unit commitment continues to keep the generation on line. More detailed simulations are required (and are done as part of wind integration studies) to determine if there is a unit commitment cost associated with assuring the appropriate unit commitment.

In summary, increasing the effective size of balancing areas, either through consolidation or through sharing of balancing obligations, reduces the cost of wind integration. Sub-hourly energy markets provide incentives and rewards for generators to respond to ramping needs. Together, these two effects greatly reduce the cost of integrating wind and mitigate the expected dramatic increase in integration costs as wind penetration levels increase.

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14. ABSTRACT *(Maximum 200 Words)*
Balancing area reserve sharing holds the promise of significantly reducing wind integration costs. It also reduces utility costs without wind. Some recent studies of integrating wind into large power systems indicate that wind integration costs may rise more smoothly than previously assumed, based on analysis of smaller power systems. The "hockey stick" pattern of dramatically increasing wind integration cost above some threshold wind penetration may not be as pronounced as expected. The existence and location of this dramatically increasing integration cost could have important implications regarding the cost of achieving 20% of all domestic electricity from wind. This paper examines wind integration costs as a function of balancing area size to determine if the larger system size helps mitigate wind integration cost increases. Using data from Minnesota, we show that ramping requirements can be reduced by balancing area consolidation. We also examine the ERCOT and NYISO sub-hourly energy markets to understand how they incentivize generators to respond to ramping signals without having to explicitly pay for the service.

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Wind; utility; utilities; integration; system integration; balancing area; wind costs; integration costs; electrical grid; grid; load management; electrical loads

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