Session: Utility Issues: Wind Integration with Utility Operations and Markets

A Method and Case Study for Estimating The Ramping Capability of a Control Area or Balancing Authority and Implications for Moderate or High Wind Penetration

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In several regions of the United States there has been a significant increase in wind generation capability over the past several years. Increasing and volatile natural gas prices have made wind energy even more attractive, and recent renewable portfolio standards will also result in additional wind development. As the penetration rate of wind capacity increases, grid operators and planners are increasingly concerned about accommodating the increased variability that wind contributes to the system.

In this paper we examine the distinction between regulation, load following, hourly energy, and energy imbalance to understand how restructured power systems accommodate and value inter-hour ramps. The individual services are defined and the underlying cost components for each service are identified. We use data from two restructured markets, California and PJM, and from WAPA's Rocky Mountain control area to determine expected load-following capability in each region. Our approach is to examine the load-following capability that currently exists using data from existing generators in the region. We then examine the levels of wind penetration that can be accommodated with this capability using recently collected wind farm data. We discuss how load-following costs are captured in restructured markets, what resources are available to meet these requirements, why there are no explicit load-following tariffs, and the societal importance of being able to access generator ramping capability. Finally, the implications for wind plants and wind integration costs are examined.

Introduction

Wind power plants are becoming much more common in the United States and around the world. As a result of this expansion of wind generation, grid operators, utilities, regulators, and customers are increasingly interested in the impact on electricity costs and operations. The recent studies that have addressed this issue generally divide wind's impact into several time scales that correspond to operational practice. Because the grid is an extremely large machine, the logical framework for analyzing the impacts of wind begins with an analysis of the physical impacts. From there, the cost of those impacts can be calculated.

This paper focuses on the load-following time frame, which generally encompasses periods ranging from 10-minutes up to a few hours. In this time frame, slow-start thermal generation that has already been committed (started) so that sufficient resources are available to supply the expected load plus a reserve obligation can be maneuvered to accommodate fluctuations in wind and load. Combustion turbines or other fast-start units could be started in this time frame though that capability is not considered in this paper (hourly availability data is not public). Our analysis examines the thermal generation load-following capability that exists in three control areas based on publicly available data. We then examine various wind generation scenarios to determine whether the control areas have sufficient load-following capability to accommodate wind. We believe that this method, which is not as detailed as a full unit commitment and economic dispatch study, is useful in gaining a conceptual understanding of the factors driving load-following costs. It may also be useful as a screening tool prior to investing the time and effort in a more thorough study.

Balancing Generation and Load: Regulation, Load Following, Energy Markets, and Energy Imbalance

Load and generation must be continuously balanced on a nearly instantaneous basis in an electric power system. This is one of the characteristics that makes supplying electricity different from providing any other public good such as natural gas, water, telephone service, or air traffic control. It is a physical requirement that does not depend on the market structure. How load and generation are balanced does depend, in part, on the structure of the electricity markets. One benefit of interconnecting multiple control areas is that balancing load and generation within a single control area does not have to be perfect. The North American Electric Reliability Council (NERC) has established rules governing how well each control area must balance load and generation. Control Performance Standards 1 and 2 (CPS1&2) establish statistical limits on how well each control area must balance minute-to-minute fluctuations. Inadvertent interchange accounts track longer term differences. In all cases the total system remains in balance (otherwise blackouts occur). When one control area fails to balance its load with its generation, generation in another control area provides the balance.

The balancing of aggregate load with aggregate generation is accomplished through several services that are distinguished by the time frame over which they operate.

Regulation and load following (which, in competitive spot markets, are provided by the intra-hour workings of the real-time energy market) are the two services required to continuously balance generation and load under normal conditions (Kirby and Hirst 2000). Figure 1 shows the morning ramp-up decomposed into base energy, load following, and regulation. Starting at a base energy of 3566 megawatts (MW), the smooth load-following ramp (blue) is shown rising to 4035 MW. Regulation (red) consists of the rapid fluctuations in load around the underlying trend, shown here on an expanded scale to the right with a ±55 MW range. Combined, the three elements serve a total load (green) that ranges from 3539 MW to 4079 MW during the 3 hours depicted.

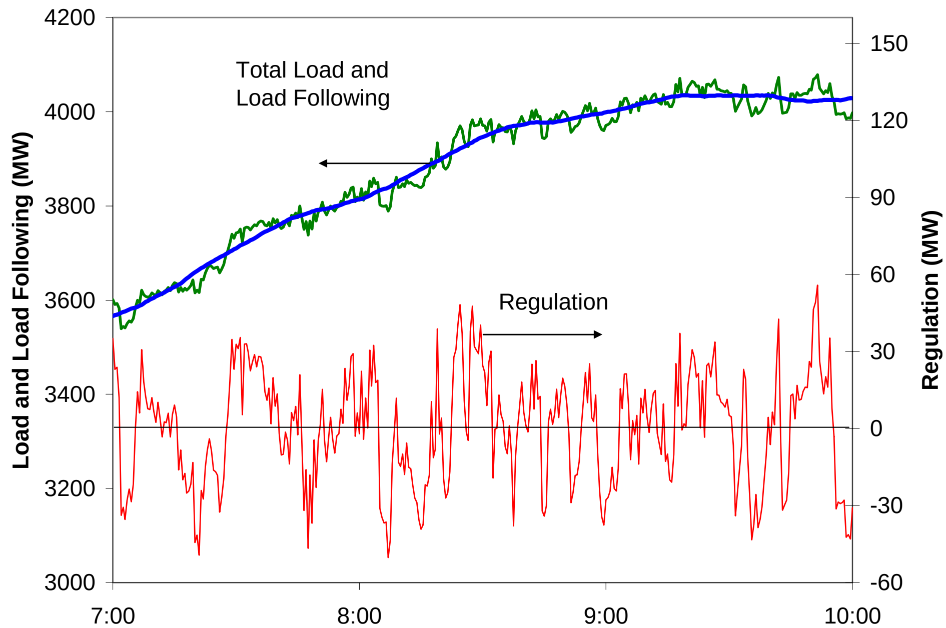

Figure 1 Regulation compensates for the minute-to-minute fluctuations in total system load. Load following compensates for the inter- and intra-hour ramps.

In the PJM region, New York, New England, and Ontario, regulation is defined as the a 5-min ramping capability of a generator. In Texas it is a 15-min service, and in Alberta and California it is a 10-min service.

Load following and regulation ensure that, under normal operating conditions, a control area is able to balance generation and load. Regulation is the use of on-line generation, storage, or load that is equipped with automatic generation control (AGC) and that can change output quickly (MW/min) to track the moment-to-moment fluctuations in customer loads and to correct for the unintended fluctuations in generation. A typical large fossil fired thermal generator may be able to ramp 1% of its capacity in 1 minute. Smaller units and combustion turbines can typically ramp faster. Hydro units typically have very fast and accurate ramping capability. Load following is the use of on-line generation, storage, or load equipment to track the intra- and inter-hour changes in customer loads. The two differ only in the time frame over which they operate.

Control areas are not able and not required to perfectly match generation and load. NERC has established the Control Performance Standard (CPS) to determine the amount of imbalance that is permissible for reliability purposes. CPS1 measures the relationship between the control area's area control error (ACE)[1] and the interconnection frequency on a 1-min average basis. CPS1 values can be either "good" or "bad." When frequency is above its reference value, undergeneration benefits the interconnection by lowering frequency and leads to a good CPS1 value. Overgeneration at such times, however, would further increase frequency and lead to a bad CPS1 value. CPS1, although recorded every minute, is evaluated and reported on an annual basis. NERC sets minimum CPS1 requirements that each control area must exceed each year.

CPS2, a monthly performance standard, sets control-area-specific limits on the maximum average ACE for every 10-min period. Control areas are permitted to exceed the CPS2 limit no more than 10% of the time. This 90% requirement means that a control area can have no more than 14.4 CPS2 violations per day, on average, during any month.

Regulation is the most expensive ancillary service, as shown in Table 1. Interestingly, control area operators do not need to specifically procure load following; it is obtained from the short-term energy market with generators responding to real-time energy prices. Regulation, however, requires faster response than can be obtained from units responding to market signals alone. Instead, generators (and potentially storage and/or responsive load) offer capacity that can be controlled by the system operator's AGC system to balance the power system.

Table 1 Average ancillary service prices (per megawatt-hour) from several markets.

	New York	**PJM**	**California**	**ISO-NE**	**Alberta**
Regulation	$28.32	$38.94	$36.43[a]	$38.80	$35
Spinning reserve	3.04	—	3.89	—	30
Supplemental reserve	1.51	—	1.57	—	17
Replacement reserve	1.23	—	0.86	—	—

Note: When available, 2003 prices are presented; otherwise, prices are from 2002.
[a] California purchases up and down regulation separately. The combined price is shown here for comparison.

In the remainder of this paper we attempt to shed light on why services that are so similar can be valued so differently. More specifically, we look at the generation mix available to three control areas to see whether there are reasons that load following should be so inexpensive. We also develop a simple method to quantify the ramping capability of a control area and discuss the implications for wind energy.

[1] The area control error is the difference between scheduled and actual net interchange with a bias included to help maintain scheduled system frequency.

Analysis Method and Data Sources

We obtained hourly load and generator data from BaseCase, version 8.0.1. BaseCase is a product of Platts. The hourly generation data is available only for units that are subject to filing reports to the Environmental Protection Agency (EPA) for the Continuous Emissions Monitoring System (CEMS). This includes thermal generators, but hydro and nuclear units do not file and are therefore not represented in the database. Certain other generators are not required to file with CEMS, including some co-generation and some low-emission gas units. For the purposes of this study, the implication is that there is some existing generation in the control area that we can't capture. Therefore, the hourly ramping capability that we calculate for the control area will be understated.

We extracted data for three control areas: PJM, California (CAISO), and WAPA's Rocky Mountain Region. Some generators in the WAPA region also participate in other control areas, so our extraction was able to identify and pro-rate the generation metered in the control area of interest. Results are presented in Table 2.

The datasets were all from 2002. Data from WAPA included generation capacity ranging from more than 400 MW to less than 1 MW. Total peak load was 3,027 MW. It was served from hydro generation with a capacity of 700 MW and 30 thermal generators with a capacity of 2,912 MW. Although the hydro system has significant ramping capability, the hourly output for hydro plants was not available and it was not possible to include that in our estimates of system ramping capability. This lack of data results in the analysis methodology seriously under estimating the system ramping capability in some cases. Wind impacts are, consequently, overstated.

CAISO peak load was 42,352 MW. We obtained hourly data from 133 thermal generators with a total capacity of 24,232 MW, which are included in our system ramping estimates. The 13,100 MW of hydro, 4,600 MW of nuclear, and 3,700 MW of other generation is not included in our ramping estimates.

In PJM we found 55,581 MW of peak load served by 45,517 MW of fossil fired generation in 375 units which are included in our ramping estimates for PJM. The 2,500 MW hydro, 13,500 MW of nuclear and 600 MW of other capability were not included in our ramping calculations.

This discussion of the datasets' limitation shows that our estimates of the control areas' ability to ramp are understated, perhaps significantly. The results of our calculations and discussion below should therefore be interpreted as a minimum floor on the ramping capability that is available from thermal resources, and that capability can be complemented by other generation that we were unable to measure.

Table 2 Energy requirements and generation mix for three control areas in 2002.

	CAISO	PJM	WAPA
Load			
Peak load (MW)	42,352	55,581	3,027
Average load (MW)	26,573	31,357	2,173
Measured Thermal Generation			
Number of generators	133	375	30
Total capacity (MW)	24,232	45,517	2,912
Highest coincident output (MW)	17,541	35,009	2,617
Largest unit capacity (MW)	761	907	410
Average unit capacity (MW)	182	121	97
Average unit output (MW)	41	44	64
Additional Generation			
Hydro (MW)	13,100	2,500	700
Nuclear (MW)	4,600	13,500	0
Other (MW)	3,700	600	11

Determining Individual Generator Ramping Capability

The first step in determining how much ramping capability is available and how much is needed is to determine the ramping capabilities of the individual generators. These capabilities are not publicly available, so we determined them by observing each generator's behavior. We analyzed a year of hourly generator output data to determine the maximum output, minimum non-zero operating output, and MW/min ramping capability for each generator. Generator maximum capability is simply the maximum hourly output the generator achieved during the year. Generator minimum capability and ramping capability are slightly harder to determine.

The minimum hourly output recorded in the data may be below the unit's actual sustained minimum operating capability. If the unit was turning on or off during the hour it would have spent part of the time at zero output, part of the time ramping on, and part operating stably. To better estimate the generator's minimum sustainable non-zero operating capability, we eliminate hours immediately after startup and immediately before shut down.

Each generator's ramping capability was determined by observing the maximum change in output between any 2 hours during the year. Upward and downward ramping were determined separately. As with the determination of the generator's minimum operating capability, hours immediately after startup and immediately before shutdown were excluded.

These estimates of generator capability are conservative. The generators may have greater capability that they simply did not have call to use during the year. Also, only hour-long ramps can be quantified. A 50 MW combustion turbine with a 20 MW minimum operating capability, for example, can be credited with a maximum 0.5 MW/min ramp rate, for example, regardless of the actual ramp rate capability. This is because the maximum change in output the unit can achieve is 30 MW and the evaluation interval is 60 minutes. The unit might be capable of ramping from 20 MW to 50 MW in under 10 minutes giving better than 3 MW/min ramp rate but the analysis methodology limits the calculated ramp rate to 1/6th that value. Conversely, this method does not capture other limitations such as temporary unit de-ratings or emissions limitations.

Knowing each generator's maximum and minimum operating capability and the up and down ramping capability allows us to determine the aggregate ramping capability available to the control area each hour of the year. System hourly MW/min ramping capability is the sum of the ramping capabilities of each generator that is on line that hour. Each generator's hourly ramping capability can be limited, for that hour, by the generator's current output and the maximum or minimum output capability. For example, a generator that is capable of 3 MW/min upward ramping would be limited to 0.2 MW/min if it had a maximum output capability of 200 MW and was operating at 188 MW during an hour (12 MW maximum ramp up / 60 minutes).

Table 3 summarizes the generator up and down ramping capabilities for the three control areas we studied. The small size (182, 121 and 97 MW for CAISO, PJM and WAPA respectively), and the even smaller operating range of most units limits the calculated ramping capability for ramps lasting less than an hour. Both CAISO and PJM have a few large units that are also relatively fast. Again, these limitations combined with the unavailability of hydro data understates, in some cases significantly, the system ramping capability and correspondingly overstates the potential impact of wind generation.

Table 3 Thermal generator ramping capabilities in MW/min.

Measured Thermal Generation (MW/min)	CAISO	PJM	WAPA
Fastest unit MW/min ramp capacity (up/down)	8.6/-7.8	9.1/-8.9	2.4/-2.4
Average unit MW/min ramp capacity (up/down)	1.6/-1.6	0.8/-0.8	0.6/-0.7
Total capacity (up/down)	215/-214	291/-306	17/-20
Total simultaneous capacity (up/down)	168/-175	160/-288	9/-19
Maximum used capability (up/down)	42/-66	54/-61	3/-6

Analyzing System Ramping Capabilities and Requirements

The ramping capability available to the control area is the sum of the individual generators' ramping capabilities. This aggregate capability varies from hour to hour as different generators come on and off and as their operating levels vary. Having determined the maximum and minimum output along with the ramping capabilities of each generator we were able to reexamine the year of load data and determine, for each hour, what the control area ramping requirements were and what excess ramping capability was available from the thermal generation. We only consider generation ramping capability that is in the same direction as the current load requirement. That is, up-bound ramping capability is evaluated when the load is ramping up and down-bound ramping capability is evaluated when the load is ramping down.

The last three lines of Table 3 present the total control area thermal ramping capabilities. As expected, the total capability of all the units exceeds the maximum capability that is ever actually available. There are two primary reasons for this. First, all the units are never on line at the same time. Second, some of the thermal units are typically operating near their full output so they have limited capability to ramp up. Interestingly, none of the control areas use the full thermal ramping capability.

Ramping Capability and Requirements in PJM, CA, and WAPA/RM

Thermal ramping capabilities typically exceed control area load ramping requirements for the three control areas we studied. Figure 2 presents histograms of both the generation capabilities and the load requirements. WAPA is a significantly smaller control area with lower ramping capabilities and needs. Consequently, the PJM and CAISO curves use a different scale than the WAPA curve. Results from all three control areas are plotted together, however, to show the similarities in the shapes and in the relative differences between the generation capabilities and the load requirements. Load ramping requirements from all three control areas are similar (other than the 20-to-1 scale factor difference between WAPA and CAISO/PJM). Ramp up capabilities are also similar. Ramp down capabilities show greater differences between the control areas. The California ISO control area tends to operate with many more generators partially loaded for many hours of the year. Generators are poised to move up or down and the generation ramping capabilities histogram is fairly symmetric. Both WAPA and PJM have more base loaded coal fired generators that tend to operate closer to full load. These systems have more ramp down capability from their thermal generators than ramp up capability. Still, thermal ramping capability exceeds load ramping requirements.

The histograms presented in Figure 2 do not show simultaneous requirements and capabilities. Figure 3 presents simultaneous load ramping requirements and thermal generation ramping capability as a ratio. Thermal ramping capability exceeds load requirements, in both the up and down directions, for all but 30, 100, and 260 hours for PJM, CAISO, and WAPA respectively. For most hours the thermal ramping capability far exceeds the load ramping requirements. The extremely high ratios of capability to requirements on the left side of the graph result from times when the load is not ramping much and are not overly significant. The excess capability represented for many hours in the middle of the graph, when the load is ramping moderately, are more important. The control areas never fell short of ramping capability; significant hydro and other ramping resources are available to each control area but are not captured in our data.

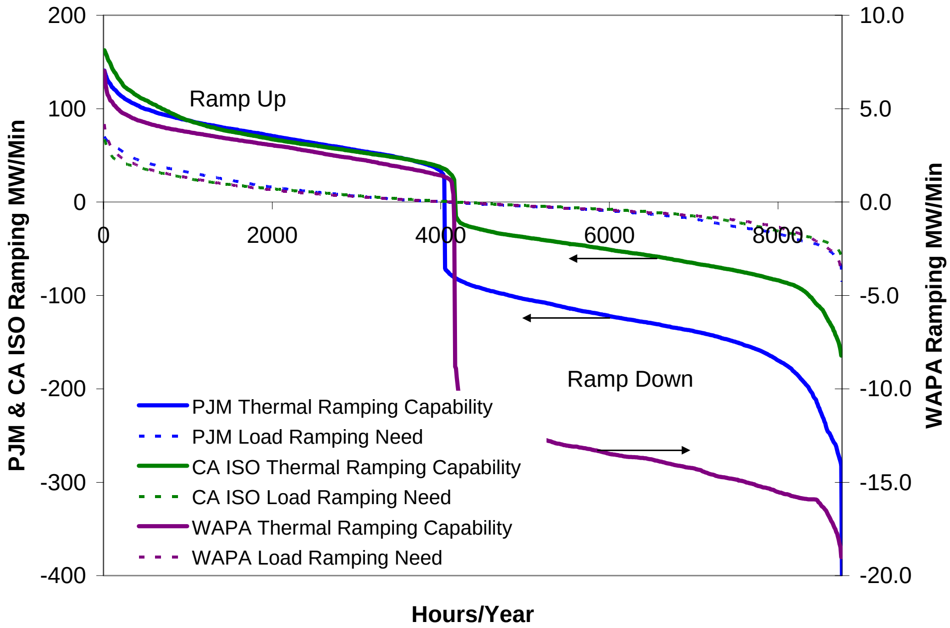

Figure 2 Thermal ramping capabilities typically exceed load ramping requirements in three control areas studied.

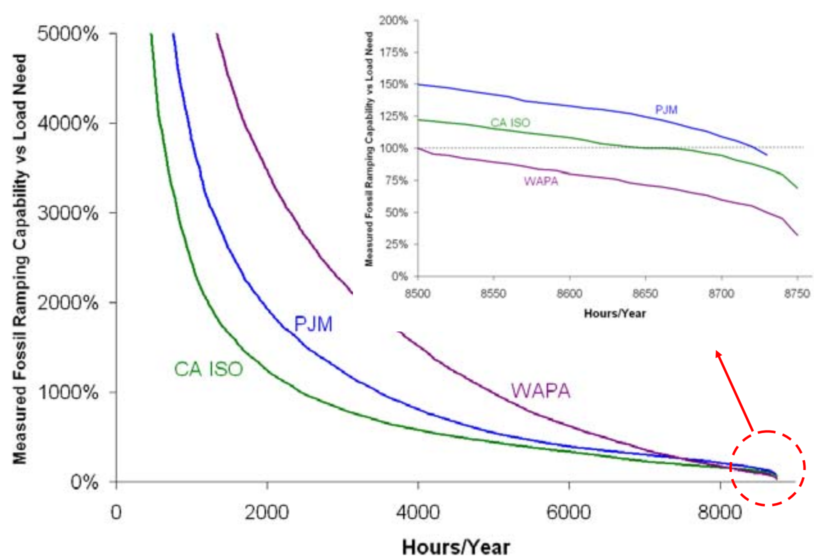

Figure 3 Thermal ramping capability exceeds load ramping requirements in all three control areas more than 97% of the time.

Adding Wind Ramping Requirements

Unfortunately we were unable to obtain wind generation data that corresponds to the load and generation. However, our main purpose is to demonstrate methods for evaluating the ramping that exists in a control area, and how that can be applied to help determine

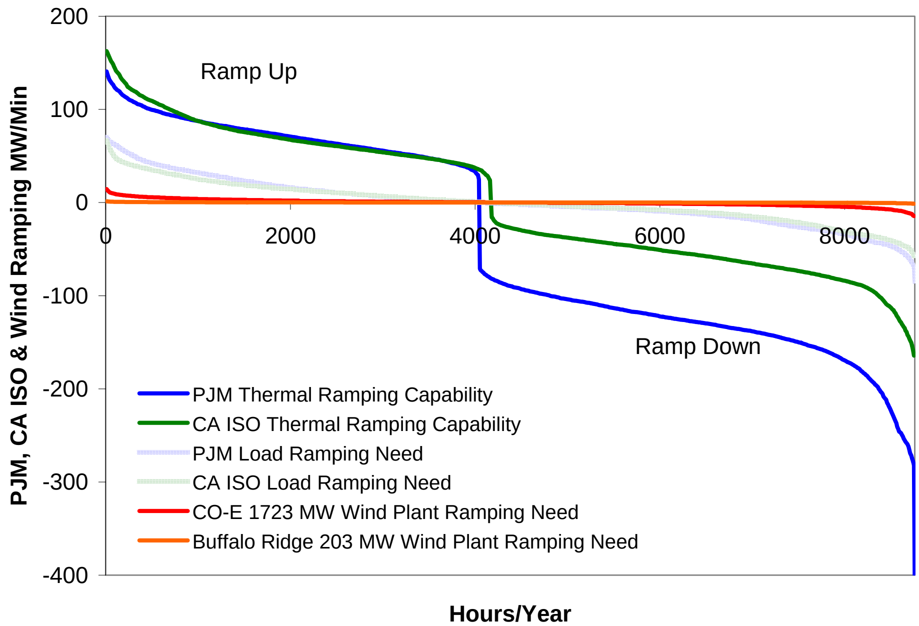

Figure 4 Ramping requirements for the 230 MW Buffalo Ridge and 1723 MW Colorado East wind plants are small in comparison to the load ramping requirements of PJM or CAISO.

whether a given size wind plant can be accommodated. We used two data sets to illustrate our method. The first came from the Buffalo Ridge Wind Plant in southwest Minnesota (Wan, 2001) The second is a hypothetical wind plant composite from Eastern Colorado, which was used in the recent RMATS study (RMATS, 2004). That data came from the Utility Wind Resource Assessment Program at the National Renewable Energy Laboratory. Hourly wind generation was calculated based on a modern 1.5 MW-class turbine. The resulting hypothetical wind plant is 1723 MW, representing a very large wind penetration for the WAPA control area.

Having determined the load ramping requirements and the ramping capability available from thermal generation we next examined the impact of adding significant wind. Figure 4 adds the ramping requirements of the 230 MW Buffalo Ridge wind plant and the 1723 MW Colorado East hypothetical wind plant to the thermal capabilities and load ramping requirements of PJM and CAISO previously presented in Figure 2. Clearly these wind plants would not present a significant additional ramping burden to either of these two large control areas.

The impact of additional wind would be expected to be much greater on the smaller western control area. Figures 5 and 6 confirm this speculation. The effect of adding the

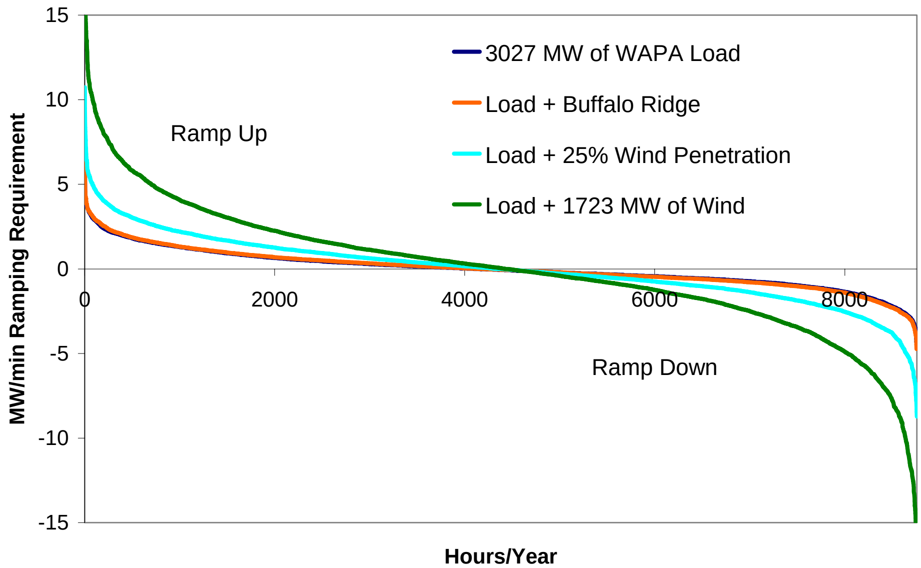

Figure 5 Adding the 230 MW Buffalo Ridge wind plant does not significantly raise the WAPA load ramping requirements, but adding 757 MW or 1723 MW of Colorado East wind plant does.

hour-to-hour wind ramping requirements to the WAPA hour-to-hour load are presented in Figure 5. The 230 MW Buffalo Ridge wind plant does not have a large impact and the orange curve showing the combination of Buffalo Ridge and the WAPA load essentially overlays the blue curve showing the WAPA load alone. The 1723 MW Colorado East wind plant significantly increases the ramping requirements, as shown by the green curve. We also scaled the Colorado East wind plant back to 757 MW (25% of the control area peak load) and show the results as the turquoise curve.

The WAPA thermal generation ramping capability is added to Figure 6. Clearly the 1723-MW Colorado East wind plant would present ramping problems for the WAPA thermal generation.

The wind/load requirements are not simultaneous with the thermal generation capabilities shown in the Figure 6 histograms. Figure 7 does present simultaneous results. Adding the 1723 MW Colorado East wind plant to the WAPA load would exceed the thermal generation ramping requirements 1655 hours in 2002. Restricting Colorado East to 757 MW would have reduced the number of hours when thermal generation could not meet the ramping requirements to 718 hours. With or without the Buffalo Ridge wind plant thermal generation can not meet the control area ramping requirements during 242 hours. It is important to remember that this analysis does not include the 700 MW of hydro generation that WAPA actually uses for ramping. It is also important to note that generation was not redispatched or recommitted when wind was added. It is also likely that additional ramping capability exists in neighboring control areas, which could increase the ability of the WAPA control area to absorb additional wind. Consequently these results are illustrative at best.

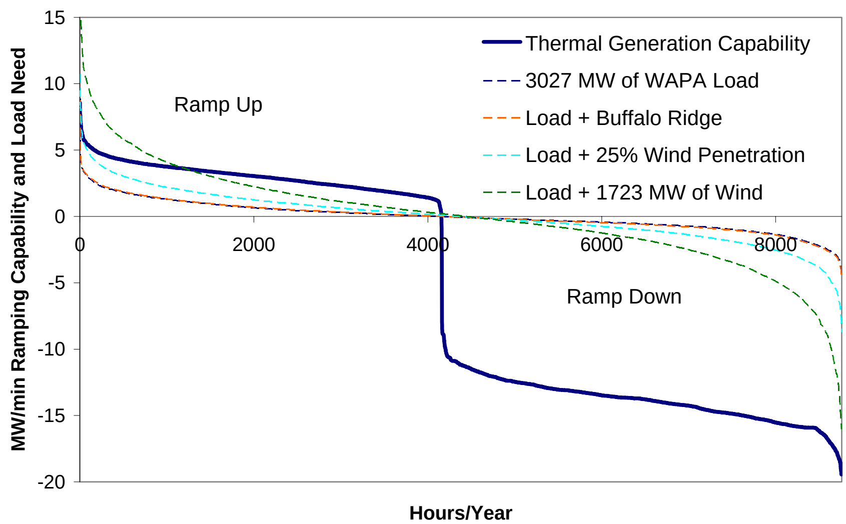

Figure 6 While significant thermal ramping capability exists in the WAPA control area up bound ramping capability would be challenged by the addition of 1723 MW of wind generation.

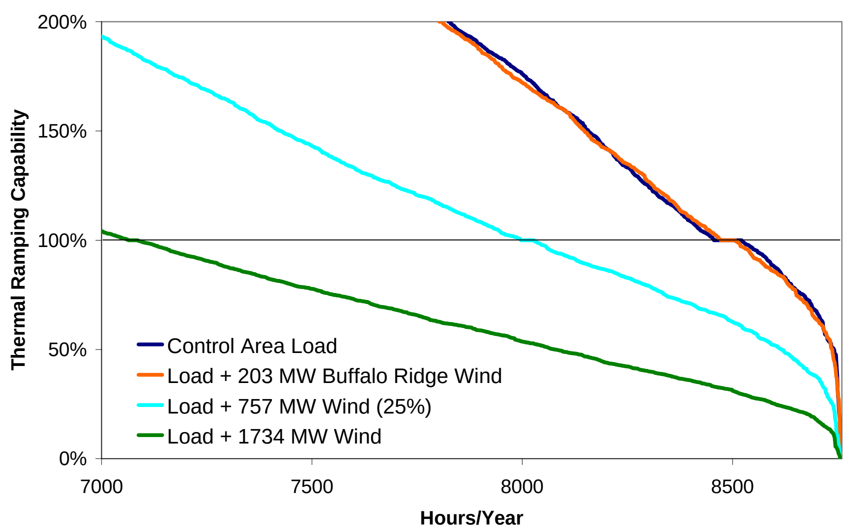

Figure 7 Thermal generation would have had insufficient ramping capability to accommodate the hypothetical Colorado East wind farm for 1655 hours in 2002.

Analysis Limitations

Although we have pointed out some of the limitations of this analysis, we would like to reiterate and expand on them here. The limitations can be separated into those involving incomplete data and those involving the specific algorithm we have used.

Because there are many generating resources that do not file with the EPA CEMS, our data set is incomplete. Our generator database does not include hydro, which can be a significant source of ramping capability. This most likely has the largest impact for WAPA, but it is also significant in CA. Certain gas and co-gen plants do not report to the CEMS. The relative impact of this omission in our data set is significant. Based on the reported measured output of generators in our database, measured generation provided 57% of the peak load in CA, 86% of the peak load in WAPA, and 63% of the peak load in PJM. Although the relative impact in the WAPA control area appears to be much smaller than in the other areas, WAPA is less than 10% of the size of the other two control areas, so the percentage does not tell the whole story.

Another data limitation is that the wind data is not from the same year as the load and generation data. We are also using wind from geographically remote locations relative to some of the control areas. We recognize that this limits the ability to interpret our quantitative results, but we believe that this approach can be useful to others.

The data can't tell us what the precise ramping capability is for the units we observed. Units that can move fast enough to reach rated capacity within an hour can't be accurately measured by our method. There may be units that can ramp quickly, but actual operation during 2002 did not call upon those units to ramp near their capability.

Limitations are also embedded in the approach. The method cannot distinguish between units that are committed and those that aren't. We ignore transmission constraints, and local issues such as volt-amps-reactive (VAR) or voltage- support requirements that may inhibit the ability of a unit to ramp during certain system conditions.

The method is not intended to be a substitute for rigorous methods that optimize unit commitment and economic dispatch such as the recent studies of wind integration impacts on the New York power system (Piwko 2005) or the Xcel power system (Zavadil 2004). In our study the added wind generation did not displace existing generation; we did not redispatch or (more importantly) recommit any of the generation. We did not have enough data about any of the generators to perform such a detailed analysis.

We feel the study still has value, however, because it provides a transparent view into the interactions between types of generation and the importance of generator ramping capability. This method allows the reader to get a feel for the size of the ramping resource that is already available from existing thermal generation. It allows a rough comparison of the size of that resource with the ramping needs of system load and wind.

Implications for Wind

Specific implications for wind generation in the regions studied must be tempered with the limitations of the available data sets. One key issue is that, because it was not possible to obtain coincident load, generation, and wind data, our quantitative conclusions are limited. However, some general conclusions can be drawn.

First, it is possible to calculate a lower bound to the ramping capability within a control area using public databases. Although in our experience some significant capabilities of the control area could not be estimated, we are confident that our estimates provide a lower-bound of the ramping capability in WAPA, CAISO, and PJM. In reality, more ramping capability exists than we were able to measure.

Second, it appears that there is a very large amount of ramping capability during most hours of the year in each region we studied. This ramping capability is a natural result of the resource mix that has developed in the area. Because each increase or decrease in wind generation does not need to be matched one-for-one by another generator, the ability of these regions to absorb moderate or even large quantities wind generation appears significant for most of the year.

All three control areas we studied appear to have significant ramping resources available from thermal generation that is partially loaded and physically able to respond. PJM and CAISO and most ISOs run energy markets that clear several times an hour, providing access to the ramping capabilities of the generators active in the energy markets. Control areas that do not have access to fluid intra-hour markets still have the physical capabilities of the generators but may not have *access* to that capability simply based on the hourly market structure. This lack of access denies the generators the ability to position themselves (ramp) to sell as much energy as customers want, forces the control area operator to use additional regulating resources instead, and forces consumers to pay for the inefficiency.

There may be significant opportunities for neighboring control areas to assist each other in the load-following time frame as well. This is partly a natural consequence of the ability of larger control areas to better manage variability, whether caused by load, wind, or a combination of both. It is also a consequence of additional capability being inherently available from a larger pool of generators.

Conclusions

Assessing the ramping capability of a control area with public data presents some challenges. Because some data are unreported, and because of the shortcomings of our method, it is not possible to obtain an accurate measure. However, having said that, we think that this type of analysis can be useful in several ways. The estimates provided by this approach provide a lower bound on the load-following capability in a control area. The approach is transparent, which makes it possible to more easily understand how the more complex methods embodied in production simulation models work. The approach could easily be extended to include data from non-CEMS-reporting resources. For entities that have access to such data, a more detailed analysis would be possible, and would provide a better estimate of the load-following capability of the control area. Combining such data with estimates of hourly wind energy production would allow for an assessment of the control area's ability to absorb significant penetrations of wind energy.

Our quantitative results are not complete. However, a few key observations emerge. Larger control areas have the ability to handle larger wind power plants. Although this may seem obvious, our method allows for a first cut at quantification. Second, the approach could easily be expanded to evaluate the ability of combined control areas, or institutional arrangements between control areas, to increase the region's ability to integrate larger quantities of wind energy.

Markets have developed that recognize the high cost and value of regulation. Similar markets have not developed for load following. Our analysis indicates that, at least for the control areas studied, there is significant ramping capability physically available most of the time from thermal generation. While regulation is a specific service a generator sells to a control area operator, ramping is what a generator does for free in order to position itself to make or discontinue the next energy sale. This points out the critical need to have mechanisms to access the ramping capabilities of generators. The ramping generator, the power system, and the other system customers benefit when generators have the freedom to respond. The alternative is to leave the available ramping capability of generators in the energy market idle and instead procure expensive regulation (while denying the maneuverable generators energy sales). Creating sub-hourly energy markets is one, but not the only, way to obtain access to this capability.

Our method generally underestimates, and in many cases significantly underestimates, control area ramping capability because it excludes hydro, fast start, and other non-reporting resources. It is quite possible, however, that a control area could have a generation mix that did not provide sufficient ramping capability to meet the load-following needs. In that case it would be necessary to find ways to pay for ramping (in order to draw resources into the market) and to charge users of the service for the costs they incur. First, however, it is necessary to determine if the system has excess ramping capability that only needs to be accessed.

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