BALANCING WIND DOWN RAMPS WITH DEMAND RESPONSE

The opportunity for load participation in ancillary service markets spurred by high wind penetration

Master's Project

Master of Environmental Management

Duke University, The Nicholas School of the Environment

By

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May 2012

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Master's Project submitted in partial fulfillment of the requirements for the Master of Environmental Management degree in the Nicholas School of the Environment, Duke University

Abstract

Large "down-ramps," inherent in the pronounced variability of wind power generation, are a threat to grid stability as the share of wind resources increases in power markets. Balancing Authorities face the challenge of how best to address the externalities that wind variability places on the grid. Our analysis assesses U.S. power markets that offer the greatest opportunities for demand response to act as a wind balancing resource. More specifically, this study evaluates market opportunities for third-party demand response aggregators to bid the capacity of responsive load into ancillary services markets to address these "down-ramp" events. This evaluation was performed through both the establishment of a qualitative framework and the creation of a quantitative, Microsoft Excel-based, model.

In the qualitative framework, we reviewed the existing wind integration literature to identify the critical characteristics of a balancing authority that are predictive of the local grid's relative capability to accommodate wind ramping behavior. In this framework, we additionally outline key qualities of loads that make them viable candidates for the demand response services required in the balancing of wind ramps. Lastly, we discuss several potential approaches for forecasting future wind penetration in a balancing authority. We have found that demand response for wind balancing can be a favorable emerging business opportunity in a power system at the confluence of these three aforementioned analyses: 1) the balancing authority's structure and other conditions lead to a limited ability to effectively respond to increasing wind penetration, and demand response is an eligible resource to participate in balancing markets, 2) the balancing authority has a sufficient concentration of load types that are viable and appropriate demand response candidates for the balancing of wind ramps and 3) there are expectations of high future wind penetration in the system.

For our quantitative analysis, we have developed a modeling tool designed to project the total size of the down ramps caused by various wind penetration levels in a given balancing authority. These projected down ramps are then related to the generation assets of the balancing authority to evaluate the efficacy with which wind ramps can be balanced with incumbent generation and to assess additional ancillary services required that could be met with demand response, among other sources.

Finally, the qualitative and quantitative evaluation frameworks we have developed are applied to a case study of the Southwestern Public Service (SPS) balancing authority in the Southwest Power Pool, where there is high wind penetration and an evolving ancillary services market. Ultimately, while we find SPS to be a very strong candidate for demand response-derived wind balancing on a number of metrics, through our quantitative analysis we nevertheless find that an abundance of installed generation capacity in the balancing authority somewhat mitigates the deleterious impact of large wind down ramps, and substantially higher wind penetrations must be achieved before SPS is truly constrained. However, demand response still may provide the least cost option for wind balancing even at lower wind penetrations. There are current policy and market barriers directly precluding load response in ancillary service markets in the Southwest Power Pool, however given policy changes happening at the national and regional levels, it appears this trend may be reversing in the near term.

The tool set we have developed here will allow third-party demand response providers to effectively and relatively quickly assess the relative merits of the business opportunity associated with attempting to sell demand response as a wind-balancing product in a given power system. In addition, the insights provided herein may illuminate several key considerations for a balancing authority seeking to address the efficacy with which wind down ramps can be balanced in future grid operations.

Acknowledgments

We would like to formally extend our gratitude to our master's project advisor, Dr. Lincoln Pratson (Director of the Nicholas School's Energy & Environment Program), for his guidance and support during this research effort. Dr. Pratson's advice and mentorship has been invaluable to us not only in the successful completion of this work, but throughout our time as students at the Nicholas School of the Environment.

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This Master's Project reflects a collaboration of all of the authors and fulfills the degree requirements of Duke University's, Nicholas School of the Environment, Masters of Environmental Management (MEM) program. While broadly contributing to the whole of the project, each author held primary responsibility to specific areas of research in order to provide the most comprehensive study.

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Executive Summary

The reliability imperative for balancing authorities requires constant matching of demand (load) and supply (generation). For instance, when a large amount of load on a power system "turns on" or when aggregate system demand spikes, system generation must increase in concert. Similarly, when a generation unit unexpectedly fails, balancing authorities must be prepared to correct for the shortfall in energy supply nearly instantaneously. At high wind penetration levels, an unexpected large decrease in available wind generation (a down ramp) shares a lot of similarities with this generator failure scenario[1]. To deal with these events of balancing generation and load on short time scales, balancing authorities employ the use of ancillary service markets[2].

Within ancillary services, maintaining the balance between generation and load has typically been performed by making adjustments to the generation side of the power system. Generation resources capable of responding within the appropriate time frames (from seconds to within an hour, depending on the particular ancillary service) are called upon to increase or reduce generation to match the movement of system load. Conceptually, however, matching generation and load can also be accomplished by directly controlling load through demand response. As this report will discuss, demand response participation in ancillary services markets is a growing trend. In many markets, increasing wind penetration levels are expected to require expansion of ancillary services, and demand response may prove to be one the most effective resources available to grid operators in meeting the demands of these changing market conditions.

In this analysis, we consider the impact that increasing wind penetration will have in U.S. electricity markets. In particular, we focus our analysis on the issue of large wind "down-ramps", and how grid operators respond when substantial production from wind energy in a balancing authority quickly and unexpectedly decreases. A review of the numerous analyses that have been performed on wind integration demonstrates that the specter of large wind down-ramps will require increased reliance on ancillary services. This report evaluates the opportunity available for demand response to participate in the growth of these ancillary service markets resulting from high levels of wind penetration. As part of this evaluation, we present both qualitative and quantitative frameworks that can serve as tools in assessing this market opportunity for a given balancing authority.

[1] For reasons we will discuss, wind down ramps also have some key differences compared to contingency events such as unexpected large generation unit failure

[2] In markets wholly operated by vertically integrated utilities rather than a separate grid operator such as an ISO or RTO, ancillary services may not exist in the "market" sense. However, functionally ancillary services most certainly exist - utilities simply take on the task of matching load and generation entirely themselves.

1.0 Introduction

In Section 1 of this analysis, we present background information on the three primary focus areas that are at the confluence of our project: the growth of wind energy in the United States, demand response, and ancillary service markets.

In Section 2, we introduce a qualitative framework through which the market opportunity for using demand response in ancillary service markets expands as a result of increases in wind installations.

In Section 3, we present an approach to quantitatively assess the impact of wind down-ramps in a given balancing authority under a set of increasing wind penetration scenarios. The model seeks to characterize wind ramping potential in the balancing authority on a number of key metrics It also evaluates the expected capability of existing generation infrastructure to be able to flexibly adjust generation to balance this wind ramping behavior. For a given area, the model determines the level of wind penetration at which existing infrastructure is inadequate for wind balancing as well as an estimate of the cost associated with performing this balancing service exclusively with generation.

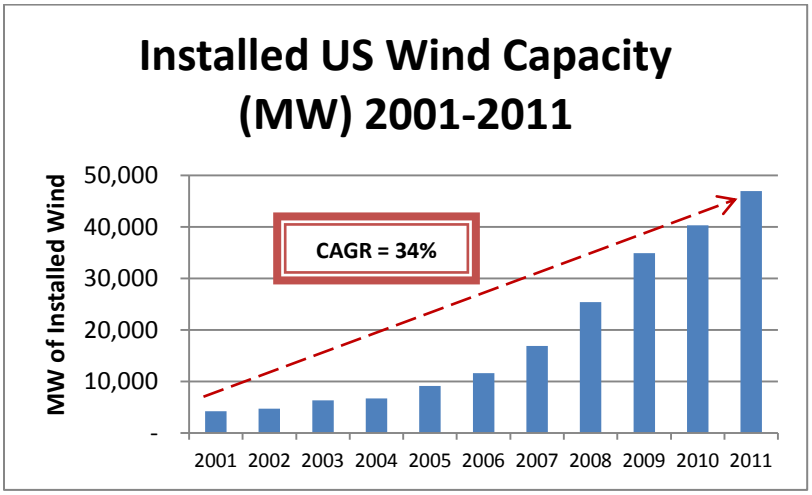
In Section 4, we apply both the qualitative framework developed in Section 2 and the quantitative model introduced in Section 3 to a case study of a balancing authority, Southwestern Public Service (SPS). In applying both our quantitative and qualitative tools to SPS, we are able to highlight the potential opportunities for demand response to participate in ancillary service markets driven by wind growth in the region, and are also able to illuminate several significant barriers to participation and other likely challenges in our case study market.

2.0 Background

2.1 Wind Market in the United States

Wind power has seen significant growth in U.S. electricity markets in the past decade. As shown in Figure 2.1 below, installed wind capacity has grown at a compound annual rate (CAGR) of approximately 34% between 2000 and 2011.

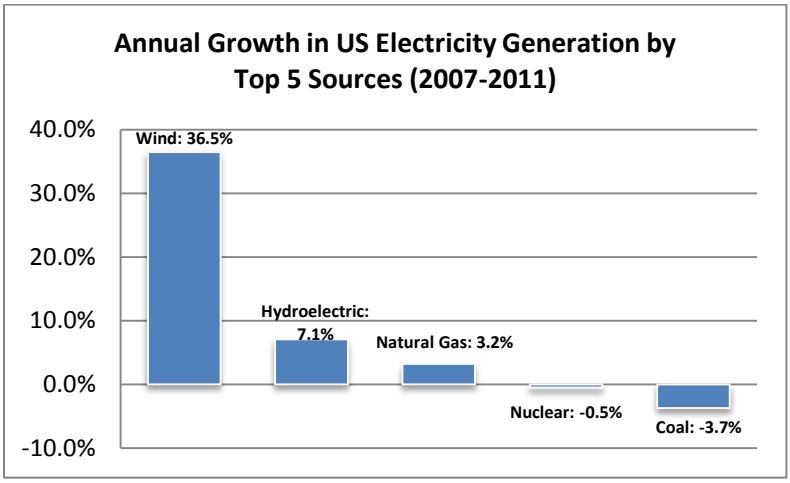
Figure 2.1 – Installed US Wind Capacity, 2001-2011



Data Source: AWEA

Growth in the wind industry has been stimulated by a variety of policy drivers, as well as the increasingly favorable economic attractiveness of building wind generation[i]. While some regions are endowed with combinations of superior wind resources and other favorable political conditions that have led to more rapid growth in wind installations than in others, particularly in recent years the impressive expansion of wind generation has occurred throughout the country. Through 2010, four U.S. states had achieved greater than 10% wind penetration (by installed capacity), and a total of 13 states derived at least 5% of their annual energy from wind generation[ii]. At the end of 2011, over 100 wind projects were under construction across 31 U.S. states and Puerto Rico, representing a total capacity of 8.3 GWs in new wind installations[iii]. Further emphasizing the recent growth trend in wind installations is a comparison of wind with the other leading generation sources for the U.S. electric system. As Figure 2.2 demonstrates, wind has vastly outpaced other technology types in recent years in terms of growth rates.

Figure 2.2 – Annual Growth in U.S. Electricity Generation by Top 5 Sources (2007-2011)



Data Source: EIA

Continuing such a similar pace of growth in the U.S. wind market going forward will not come without significant challenges and constraints. Policy uncertainty, specifically related to the production tax credit (PTC) and other economic incentives, is currently tempering the enthusiasm for continued market expansion[iv]. Unless substantial transmission infrastructure investments can be made to enable project development in the best wind sheds, insufficient transmission capacity in regions with the richest wind resources acts as an upper bound limit on wind development[v]. Introducing substantial quantities of energy from intermittent generation resources to power systems that have traditionally operated with large, centralized and dispatchable thermal plants can be a costly operational challenge for power grid managers. The topic of this paper, the use of and need for operative reserves to balance large wind down-ramps, is only one of suite of integration challenges grid operators face as wind becomes an increasingly significant contributor to a power market's generation portfolio.

There is reason, however, to be believe that wind will continue its notable growth trajectory, at least in the near term. Current state RPS policies alone are projected to drive average annual additions of new renewable energy capacity of 4 to 6 GW per year between 2011 and 2020, which is roughly equivalent to the quantity of renewable capacity added nationally in 2010 (of which the large majority of installed MWs were from wind)[vi]. Recent research has documented the levelized cost of electricity (LCOE) for newly installed wind energy to be at an all-time low. This same analysis projected that wind's LCOE between the 2012 and 2013 timeframe could be as much as 24-39% lower than the previous all-time low, assuming continued improvements in availability, O&M costs and financing rates[vii].

It is beyond the scope of this analysis to consider the U.S. wind industry's forward growth prospects, or to specifically project growth rates either nationally or on a regional basis. The focus of this report is rather to illuminate a particularly important issue that arises under increasing penetrations of wind generation, and to consider the implications of high wind penetrations for both grid operators as well as potential solutions with business models related to the wind integration challenge.

As wind and load fluctuate they place pressure on the dispatachable capabilities of a control area. Wind is often thought of as negative load because as wind power output decreases it impacts the grid's ability to meet demand, the same as an increase in load. Symmetrically, as wind power increases it decreases the required generation of a system's dispatchable generation, the same as a decrease in demand. It is when wind and load move in opposite directions that a control area's ability to match supply with demand is most diminished. Further, wind is both more variable and less predictable than load, and therefore constitutes a demand on the system that requires greater ancillary service support. As wind's market share grows, so does the magnitude of its impact on a system's stability. This is particularly true when wind power declines significantly within a short period of time because the only way to compensate is to either increase supply or decrease demand. Large wind increases, on the other hand can be compensated for through the curtailment of wind generation if need be.

A wind ramp, for the purpose of this study, is defined as a monotonic change in wind power generated. A monotonic change in wind is defined one or more step changes in power output of the same direction over a set of temporal step changes of recorded wind power generation.

There is extensive literature on the issue of wind energy integration[3]. As a variable and non-dispatchable resource, high levels of wind energy impose a number of distinct challenges for grid operators. This paper focuses specifically on the implications of one of these challenges, large wind down ramps, and one of the primary mechanisms by which grid operators deal with this challenge, the deployment of ancillary services.

[3] Readers are referred to a review of the publication library provided by the Utility Wind Integration Group (UWIG), available online at: http://www.uwig.org/opimpactsdocs.html. UWIG maintains an extensive database of utility and power market specific wind integration studies, as well as academic and industry literature on the complex and multifaceted topic of wind energy grid integration.

2.2 Ancillary Services

Balancing authorizes require ancillary services (see Figure 2.3 below) to help maintain a balance between supply and demand. FERC defines ancillary services as those 'necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."[viii] Ancillary services provide a range of functions – from regulation, which is a second to second load balancing service, to replacement or supplemental reserves, which replenish loads and begin responding within 30 to 60 minutes. Our study specifically focuses primarily on using demand response as operating reserves, which are made up of spinning and non-spinning reserves.

Figure 2.3 – Summary of Ancillary Services

Service	Response Time	Duration	Cycle Time
Regulating	Online resources that can respond immediately to system-operator requests for up and down movements		
	~1 minute	Minutes	Minutes
Spinning Reserve	Online generation, synchronized to the grid, that can increase output immediately in response to a major generator or transmission outage and can reach full output within 10 minutes		
	Seconds to <10 minutes	10-120 minutes	Hours to Days
Non-Spinning Reserve	Same as spinning but does not need to respond immediately; can be offline but must still be capable of reaching full output within 10 minutes		
	<10 minutes	10-120 minutes	Hours to Days
Replacement/ Supplemental Reserve	Begins responding in 30-60 minutes; used to restore spinning and non-spinning reserve to pre-contingency status		
	<30 minutes	2 hours	Hours to Days

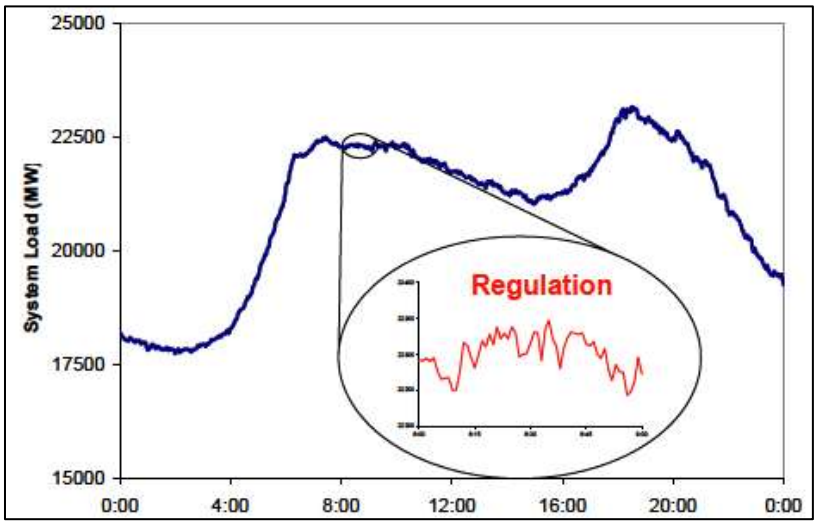
Adapted from Kirby, 2006

2.2.1 Regulation

Regulation Service provides continuous minute-to-minute balancing of generation and load under normal condition. This is the most expensive ancillary service (from a utility or balancing authority's perspective). FERC defines regulation as "the capability to inject or withdraw real power by resources capable of responding appropriately to a system operator's automatic

generation control (AGC) signal in order to correct for actual or expected Area Control Error (ACE) needs."[ix]

Figure 2.4 – Frequency Regulation Illustration



Source: Kirby, 2006

2.2.2 Operating Reserve - Spinning Reserves

Spinning Reserve Service is generation (or responsive load) that is ready to respond immediately in case a generator or transmission line fails unexpectedly. Spinning reserves begin to respond immediately and must fully respond within ten minutes. Enough operating reserves (spinning and non-spinning) must be available to deal with the largest failure that is anticipated. Some regions currently allow responsive loads to supply spinning reserves but many do not.[x]

2.2.3 Operating Reserve - Non-Spinning Reserves

Non-Spinning Reserve Service is similar to spinning reserve except that the response does not need to occur immediately. Full response from non-spinning reserves are still expected to be within 10 minutes. If a responsive load can provide spinning reserves, it is also capable of providing non-spinning reserve.[xi]

2.2.4 Supplemental/Replacement Reserves

Supplemental or Replacement Reserves are additional reserves that are required in some regions. These reserves begin responding in 30 and 60 minutes. The primary difference between supplemental and non-spinning reserves is the response time frame.[xii]

2.3 Demand Response

Demand response is the concept of directly reducing load to respond to conditions on the power grid such as incidents of peak demand or elevated market prices. In general terms, this tool is not new for utilities, as incentive programs and tariffs that gave utilities the right to curtail certain customers' load during times of system need were implemented in the early 1970s[xiii]. In fact, historically, thought the focus on grid management has mainly been on the generation side, utility executives and engineers in the early days of the U.S. electric power industry (the 1890s) debated the merits of a simple form of demand side grid management through the implementation of time-of-day electricity rates[xiv].

Many different tools are available to grid operators and utilities in order to influence demand-side behavior that falls under the categorization of demand response. However, the demand response program that is perhaps most prevalent today is the provision of capacity during peak demand periods by quickly curtailing load for short periods of time. In many power markets in the U.S., as much as 10% of peak demand occurs during less than 1% of the entire year[xv]. However, in order to provide constant electric service and maintain system reliability, utilities and grid operators must have the infrastructure in place to meet high amounts of load during these 50-100 hours per year. These peak hours typically occur when the least efficient and the most expensive generation facilities are deployed to meet the marginal increase in demand.

Employing demand response in these instances, however, can negate the need to rely on the most expensive, "peaker" plants of a grid's generation portfolio. In the simplest sense, if the compensation required by certain customer loads to curtail their energy consumption when called upon during these peak times is less than the expected cost of employing generation assets to meet high system load requirements, then demand response will prove to be the more efficient, preferable option[4].

2.3.1 Third-Party Providers Versus Utility-Run Demand Response

Historically, and still today in vertically integrated markets where load serving utilities serve as their own balancing authorities, utilities served as the actors working directly with customers willing to participate in demand response in exchange for an economic incentive. However, in restructured markets across the country, it is now commonplace for third-parties to manage this aspect of demand response on behalf of utilities or balancing authorities. These companies work

[4] A more extensive description of the benefits and advantages of demand response is discussed in a later section.

directly with the end-use electricity customers, and aggregate their collective MWs of committed demand response capacity to provide utilities with a centralized point of contact for deployment of responsive load. This paper specifically examines the potential business opportunities available to these third-party demand response aggregators, and considers the relative merits of focusing a new ancillary-services based demand response business model in one balancing authority versus another. However, the findings contained herein, have value to other stakeholders such as utilities or balancing authorities that are considering wind integration, demand response and ancillary service markets from alternative perspectives, such as long term grid planning and policy-making.

In addition to the stakeholders involved, demand response programs can be differentiated in a number of ways. There are, however, three characteristics of such programs that can be particularly helpful for defining a program and in contrasting different demand response programs with one another: customer type, compensation structure, and the frequency and duration of "deployment."

2.3.2 Customer Type

Demand response programs can rely on load curtailment from load types of all sizes, from the small residential loads, to commercial and light industrial loads, to the loads of heavy industrial energy electricity consumers. For purposes of efficiency, smaller loads will tend to be more automated, and participants will permit the utility or grid operator to more directly control the curtailment of load. As loads become larger, and the energy customer tends to be more sophisticated, the process of curtailing load is likely to be more collaborative between the load source and the grid operator[5].

2.3.3 Compensation Structure

As discussed above, one form of compensating load types for reducing load in times of system need is through differentiated pricing. This concept can be applied generally across the system, where time-of-use pricing is applied to all customers, and market forces are expected to drive flexible energy consumption to times of lower total energy demand (and consequently, lower prices). Differentiated pricing can also be implemented in a more targeted manner, where loads that specifically agree to curtail their load when called upon in exchange for reduced electricity rates[xvi].

An alternative approach is through direct payments from the utility or grid operator for the provision of demand response, much in the same way generators are compensated for their activities and the services supply-side resources can provide to the market. Loads can be

[5] See Load Analysis discussion in Section 3.3

compensated in terms of the capacity ($/kW or MW) per unit of time (e.g. per month, per year, etc.) that can be curtailed when called upon. Compensation can also come in the form of energy payment ($/kWh or MWh), as loads are paid for each unit of energy they reduce when capacity is actually deployed. Most demand response programs rely on some combination of these two compensation structures, where incentives are provided both in terms of capacity and energy (which, of course, is similar to much of the compensation typically provided to supply-side resources as well). The specific breakdown of the relative importance of these two payments for demand response customers will depend on the specific characteristics of the demand response program in question, namely if it is more oriented towards the provision of energy or capacity – a topic which will be briefly introduced below.

2.3.4 Frequency and Duration of Deployment

Demand response programs will differ on the basis of how often "peak" conditions reach the point at which it becomes more preferable to rely on load reduction rather than generation increases. The characteristics of the generation base in the market, the overall load profile in the system, the specific load types involved in the demand response program and both their willingness and technical ability to curtail load are just some of the variables that lead to differences in various demand response programs.

The objective of a demand response program will also lead to differentiation between programs on this metric. Reliability-oriented programs designed to curtail load in rare, emergency, conditions will tend to be capacity-oriented. Although demand response participants will be expected to curtail load when called upon, actual curtailments will be infrequent (once to several times per year) and for short durations. As a result, the compensation design will focus more on the capacity offered and less on the energy provided when called upon.

Historically, demand response has been largely confined to this end of the spectrum of capacity versus energy. However, more recently in a number of power systems in the U.S., demand response is increasingly being seen as a viable resource in a different area of power markets: ancillary services. While not purely energy-based, many of the submarkets for ancillary services require much more frequent deployment and longer durations than what is typically provided in conventional, peak load focused demand response.

2.3.5 Advantages to Demand Response

There are a number of key advantages (listed below) to using demand response for the provision of ancillary services that underpin the importance of this analysis for grid operators, in addition to compelling business opportunities in this arena for third-party demand response providers. Many of the advantages of demand response are in parallel to other demand response markets, such as emergency peak load management. However, given the increased frequency with which ancillary services are called upon, the advantages of demand response are perhaps even more notable in this context.

Increased Competition and Lower Cost

With a broader set of potential providers of ancillary services, increased competition is likely to drive down the cost borne by the rate payer. Moreover, considering that the marginal cost of responsive load is likely to be much lower than many of the natural gas fired incumbent market participants, demand response is likely able to bid lower than the market clearing price for services.

Improved Utilization of Existing Resources

With demand response able to provide crucial capacity within ancillary service markets, generation capacity does not need to be "held back" and can operate at optimum levels, reducing depreciation of generation assets and allowing for operation at more cost and emissions-efficient levels.

Postpone Need for New Capital Investment

Similarly, using existing demand response assets may be able to lead to cancelling, or at least delaying, the need for grid operators to invest in and build new generation assets (or transmission assets), specifically to meet reliability and capacity concerns related to ancillary service markets.

Potential lower performance risk

Using demand response, the same amount of MWs of ancillary market capacity would tend to be aggregated from a number of customers, rather than potentially from just a single generation unit. So long as the appropriate infrastructure is in place to coordinate among the various aggregated loads, a more distributed portfolio of capacity providers may lead to a distributed, and decreased, risk associated with performance failure.

2.4 Demand Response in Ancillary Services Markets Across the U.S.

Despite these benefits, demand response participation in ancillary services markets in the United States remains relatively limited to date (see Figure 2.5 for a general overview and Table 2.1 for specific programs below). Of the organized RTO and ISO power markets, ERCOT and PJM are the most mature or aggressive (i.e. they have done the best to integrate demand response into ancillary services markets), while NYISO has an immature market (i.e. it has a market in place but no active participants). Other regions either have nascent or nonexistent markets. MISO is currently in the process of developing its market for inclusion of demand response into ancillary services, while CAISO and ISO-NE only have pilot projects, although the latter hopes to have a legitimate market in the near term.

Figure 2.5 – Overview of Demand Response Participation in Ancillary Services Markets Across the U.S.

Power Market	Ancillary Services	Level
ERCOT	Operating Reserves	Mature
PJM	All	Mature
NYISO	All	Minor
MISO	All	Minor
CAISO	All	Pilot
SPP	None	N/A

Image Source: Aces Power Marketing

The following is an overview of the programs within each market.

ERCOT[xvii]

Within its existing ancillary services market, the Electric Reliability Council of Texas (ERCOT) currently has a program called "Load Acting as a Resource" (or LaaR) that allows demand response to participate and provide operating reserves. Demand response is eligible to provide Non-Responsive Reserves (i.e. 10-minute non-spinning reserves) and up to 50% of Responsive Reserves

(i.e. spinning reserves) and balancing energy services. ERCOT will only recognize loads (including aggregated loads) of at least 1 MW[xviii].

PJM[xix]

PJM's Economic Load Management program allows demand response to compete with generation in the provision of regulation, spinning, and supplemental reserves. Demand response can provide spinning reserves, regulation, and 30-minute supplemental reserves. In order to participate in the spinning reserve market, the focus of our project, demand response resources must have:

- The ability to curtail load within 10 minutes
- 1-minute interval metering
- A minimum 0.5 MW offer
- 24-hour All-Call availability

In addition, demand response cannot provide more than 25% of the markets requirement for spinning reserves, regulation, and supplemental reserves.

MISO[xx,xxi]

The Midwest Independent Transmission System Operator (MISO) allows demand response to participate in its energy and ancillary services markets. Demand Response Resources (DRRs) can also be nominated as capacity resources (i.e. counted towards the resource adequacy requirement). MISO has two types of DRRs. Type I DRR is a resource capable of supplying energy or contingency reserves through physical load interruption. Type II DRR is a resource capable of supplying energy, contingency and regulating reserves through behind-the-meter generation[xxii,6] or controllable load. Type II DRR may provide energy, capacity, and all types of ancillary services. DRR Type I is not allowed to participate in the regulation market, but can provide energy and other types of ancillary services.

NYISO[xxiii,*xxiv*]

The New York Independent System Operator (NYISO) ancillary market contains a Demand Side Ancillary Services Program (DSASP) that allows retail customers that can meet telemetry and other resource load requirements with an opportunity to bid their load curtailment capability into the

[6] Behind-the-meter generation is when one or more generation units are located with the load at a single location and does not need transmission or distribution facilities to deliver energy from the generation unit(s) to the load.

Day-Ahead Market and/or Real-Time Market to provide operating reserves and regulation service. Scheduled offers are paid the appropriate marketing clearing price for reserves and/or regulation.

ISO-NE[xxv,xxvi]

In the Independent System Operator-New England (ISO-NE), demand response is not eligible to provide reserves to the wholesale power market. However, ISO-NE tested a Demand Response Reserves Pilot starting in 2006 until May 2010. The pilot tested the ability of smaller demand response resources to respond to ISO dispatch instructions in a manner similar to supply-side resources currently providing operating reserves. Currently, ISO-NE wants to allow full participation of demand resource in regulation but has yet to implement this scheme.

CAISO[xxvii]

From 2009 to 2011, the California Independent System Operator (CAISO), in collaboration with PG&E, the Demand Response Research Center (DRRC) in California, and the Lawrence Berkeley National Laboratory, implemented an Integrating Renewable Resource (IRR) pilot to determine the feasibility of demand side storage capabilities (i.e. thermal mass, process mass, ice and cold water storage) to provide regulation and ramping services that the CAISO will need to manage the grid under a 33% RPS. This pilot is an extension of PG&E's Participating Load Pilot, which successfully moved three automated demand service response participants into ancillary services in 2009. IRR built on past research that the Demand Response Research Center conducted using Open Automated Demand Response in commercial and industrial facilities and providing non-spinning reserves to the CAISO.

Table 2.6 – Demand Response Programs in Ancillary Service Markets

Market	DR Programs
ERCOT	➢ Load Acting as a Resource (LaaRs)
PJM	➢ Economic Load Management
MISO	➢ Type 1: Physical Interruption ➢ Type 2: Behind-the-Meter or Interruptible Demand
NYISO	➢ Demand Side Ancillary Services Program (DSASP)
CAISO	➢ Integrating Renewable Resource (IRR) Pilot
ISO-NE	➢ Demand Response Reserves Pilot

2.5 FERC Regulation

The Federal Energy Regulatory Commission (FERC or the Commission) has weighed in on the issue of further integrating demand-side resources into whole energy markets such as ancillary services in recent years. In 2009, FERC issued Order 719 which stated:

"[d]emand response can provide competitive pressure to reduce wholesale power prices; increases awareness of energy usage; provides for more efficient operation of markets; mitigates market power; enhances reliability; and in combination with certain new technologies, can support the use of renewable energy resources, distributed generation and advanced metering."[xxviii]

With this finding of support for demand response, Order 719 requires independent system operators (ISOs) and regional transmission organizations (RTOs) to take measures to ensure that demand response resources are treated comparably to generation or any other resources in market rules. As an example, the Commission stated that with respect to ancillary service markets, ISOs and RTOs must accept bids from demand-side resources if they are technically capable of providing the ancillary service in question, submit a bid in compliance with the relevant bidding rules at or below the market-clearing price[xxix]. With this policy, FERC explained that the intent was not necessarily to "favor" demand response resources, but simply to ensure a level playing field and remove barriers to market participation that frequently preclude participation from responsive load in such markets. Also of note within this FERC order is that the Commission ordered RTOs and

ISOs to modify any market rules that prevented third-party demand response aggregators from submitting bids into ancillary services markets[xxx,7].

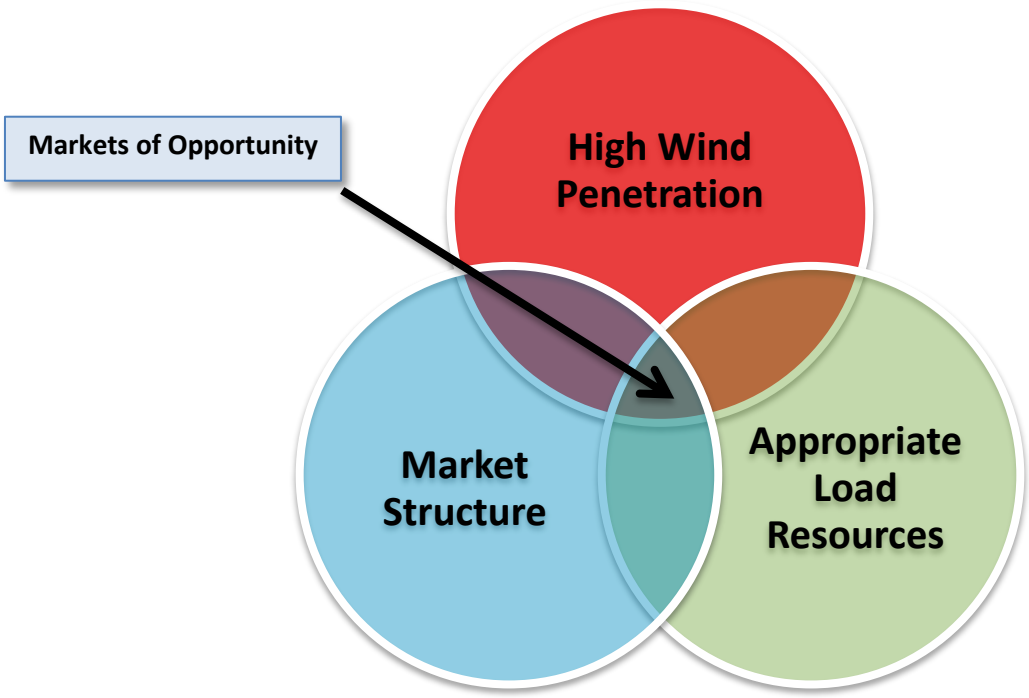
The implications of FERC Order 719 are important for the analysis performed within this project. While not every electric power market at present has rules that allow for demand-side participation in ancillary service markets, FERC Order 719 provides an indication of the direction that markets around the country are moving. Four years later, some ISOs and RTOs are still working through the regulatory process to open up their markets to demand response and comply with the directives of Order 719. Nevertheless, it is apparent that there is a growing consensus around the viability and value of including load-side resources in wholesale energy markets, and lends credence to the central thesis underpinning our analysis that demand response providers should be prepared to evaluate the best potential markets to take advantage of these emerging business opportunities. The following sections continue our discussion of the specific opportunity considered in our project – evaluating potential demand response markets driven by the rapid growth in the installation of wind energy capacity in a power system.

3.0 Qualitative Framework

One of the central tasks in this project was to propose a framework through a given balancing authority could be evaluated on the basis of its "fit" for the opportunity of using responsive load to balance wind down ramps. Such a framework could be used as an important tool of first order analysis by a stakeholder seeking to evaluate a specific market, or simply to identify the specific attributes of a balancing authority that contribute to its need (or lack thereof) for additional resources dedicated to the service of balancing wind down ramps. This framework is depicted in Figure 3.1, asserting that the markets of greatest potential opportunity for demand response providers exist at the confluence balancing authorities with high wind growth, market structures that do not allow for a great degree of response flexibility and ramping capability, and a sufficient concentration of the load types best suited to supply this demand response product.

[7] FERC did not extend a similar requirement to "smaller" utilities, defined as distributing less than 4 million MWh annually

Figure 3.1 – Qualitative Market Evaluation Framework Diagram



The purpose of such a framework is specifically to identify the factors that result in a prospective and compelling market opportunity for a demand response provider specifically looking for markets in which to introduce a demand response product targeted to meeting the need for a balancing authority to mitigate the risk associated with substantial wind down-ramps. The questions being asked implicit in this framework and in the above figure are the following:

- Does this market currently have enough wind, or is it projected to have sufficient installed wind capacity in the near term, to necessitate additional procurement of ancillary services to directly address the grid impacts brought on by this increase in variable wind generation[8]?

[8] It should be noted, of course, that even if no additional ancillary services are required – but simply that responsive load can compete effectively in the bidding processes of these markets, a profitable opportunity for a demand response provide may exist. Nevertheless, it would stand to reason that a rapidly growing market may provide a less competitive, and perhaps more compelling, opportunity than one already saturated with incumbent capacity. Also, in some cases even if ancillary services requirements are not actually increasing in overall MWs of capacity procured, the reserves may be called more frequently – thereby changing the compensation received by bid winners. Such a dynamic has been seen in Spain, where in some regions wind penetrations have reached up to 30% (in terms of energy). Operating reserves have not been

- Are the characteristics of the electricity market in a given balancing authority (market rules, current generation fleet, interconnection etc.) conducive to the flexibility and cost-effective ramping required by the integration of large amounts of variable wind generation?
- What are the characteristics of certain load types that make them effective at responding to the specific grid impacts and ancillary service market requirements of wind down-ramps? What are examples of load types that embody these characteristics? Lastly, does the balancing authority in question have a sufficient concentration of these load types to provide enough of a prospective partner-base for a demand response provider to be compelled to focus in this geographic market?

3.1 Wind Penetration Analysis

Of primary importance in the effort to identify markets of opportunity for this demand response application is to evaluate the wind penetration, or projected near term wind penetration, of the given balancing authorities of interest. The purpose of this analysis is not to identify a specific wind penetration level at which balancing authorities reach a critical threshold and the need for additional wind-following resources is required – every balancing authority will vary in this regard due to a combination of a multitude of variables. As a potential filter to identify a potentially compelling market however, this analysis seeks to identify power markets' most likely to have wind penetration levels that can be broadly referred to as "moderately challenging to very challenging," identified in the literature as perhaps in the range of 15-35% or more of annual energy production[xxxi].

3.1.1 Defining Wind Penetration

When evaluating wind levels in a power market, it is important to define the metrics by which one describes wind power's participation on the grid. Several different definitions of wind penetration are commonly referred to in the literature[xxxii]:

Wind Energy Penetration (%) – Total energy production from wind generation in a given time period (typically annually), normalized by total energy consumption in the energy system during this same period.

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increased, but are called upon more often. Further discussion of this point is found in *Impact of Electric Industry Structure on High Wind Penetration Potential*, by Milligan, et. al. and published by NREL in 2009.

Wind Power Penetration – A measure that identifies, at a given point in time, the wind power output (in MW) and is normalized by total system output at that time

Wind Installed Capacity Penetration – Total installed wind capacity (in MW), normalized by the capacity of all generation sources, or by peak load in the power system during the over a certain time period.

For our particular analysis, a metric that describes the amount of installed wind relative to the size of the overall balancing authority (in MW) and one that focused on maximum potential energy delivery at a given point in time, rather than aggregate energy delivery over a longer time period, was deemed to be most appropriate. For this reason, we evaluated wind penetration in terms of capacity penetration, specifically total MW of installed nameplate capacity of wind, normalized by system peak load.

3.1.2 Forecasting Wind Growth

With limited proprietary insight, forecasting wind growth in a specific geographic area is an exercise fraught with imprecision. This imprecision is heightened when the forecaster is expected to make prognostications of wind development levels several years or more from the present, or predict the outcome of specific wind development projects or development in specific geographic areas (such as a small to medium sized Balancing Authority) rather than working within more forgiving geographic boundaries such as those in state-level or regional analyses.

3.1.3 Application of wind penetration analysis

In our assessment of case study opportunities to explore, one of the first tasks we undertook was to engage in a version of the aforementioned wind penetration analysis. For our purposes, it was not critical to arrive at a specific data point (e.g. installed wind as a % of peak load in 2016) for a specific power market. Rather, our tool for evaluating wind penetration levels is better utilized to compare expected wind penetrations of different markets with one another. In this regard, assuming the imprecision in the forecasting is at least relatively uniform throughout the various markets, we can identify particular power markets in which wind's share of overall installed capacity is expected to grow faster than others.

In our analysis we considered two example approaches using publicly available data to identify several comparatively attractive wind markets. We are not, however, proposing that these two approaches are the best methods for identifying markets with high wind growth relative to power

system overall size; they are put forth simply as examples of methods of using a first order filter to assessing potential wind penetration levels of a set of power systems.

Alternative approaches to survey expected wind growth in specific markets are recommended when more current or more detailed data is available.

Approach # 1: Comparison of current wind interconnection requests

As part of the project development process, wind developers must submit interconnection requests to the relevant transmission authority for the location of the proposed wind farm. These interconnection requests contain, among other data points, the proposed nameplate capacity of the project under development. The American Wind Energy Association maintains a database of wind interconnection requests (as of January 1, 2012) on a state-by-state basis[xxxiii]. There is no filter applied to these interconnection queues that provides any indication of ultimate project viability. It can, however, be asserted with virtual certainty that total MWs listed in an interconnection queue will not lead to an eventual equivalent MW figure of installed wind capacity, at least not from the specific proposed wind projects listed in the queue at any one point. Projects are frequently resized during the multi-year development process, and for a variety of reasons many projects that submit interconnection requests do not ultimately get built. That being said, comparing the interconnection queues of different balancing authorities against one another does provide insight into what geographic areas wind developers are currently favoring as potential areas of high wind growth.

Figure 3.2 demonstrates the total MW of wind developments in the interconnection queues of the ISOs in the U.S. power system. In this particular analysis, only organized ISO markets were considered, however a similar procedure could be undertaken looking more broadly at all U.S. electricity markets[9,10].

[9] ISO peak load figures were provided by FERC, as of 2011.
[10] A key assumption made in this analysis is that for states that fall into two ISOs, or sit within the footprint of one or more ISOs with some remaining area part of non-ISO territory, wind interconnection figures were assumed to be shared uniformly between the various boundaries (e.g. a state that is 30% ERCOT and 70% SPP will be assigned 30% and 70% of the interconnection queue, respectively).

Figure 3.2 – Wind Development Interconnection Queue by ISO/RTO

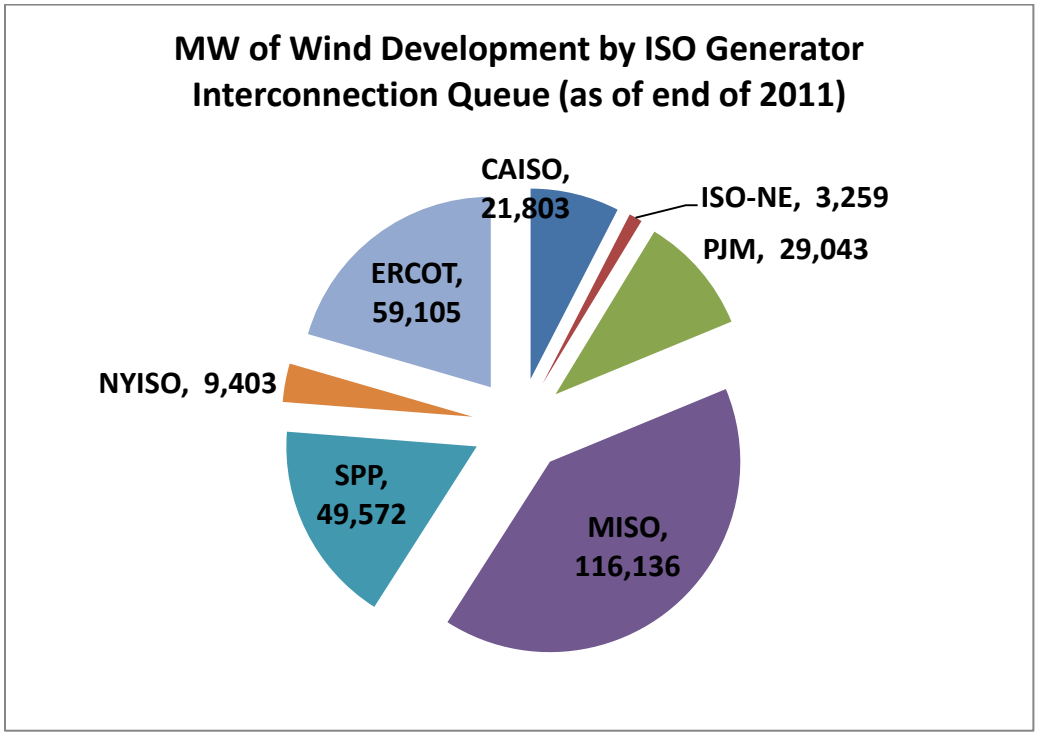
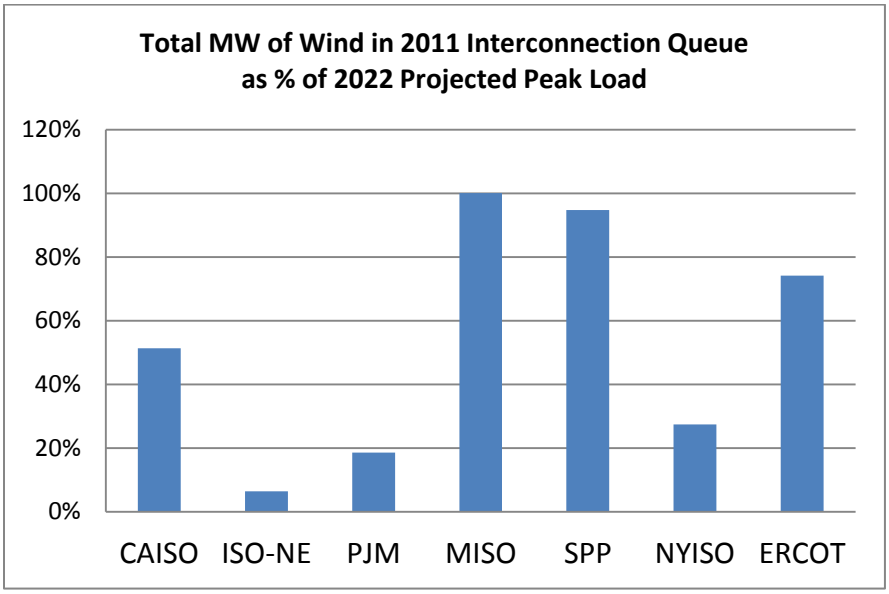


Figure 3.3 demonstrates the total amount of current interconnection requests from prospective wind projects as of the end of 2011, organized by ISO and normalized by the ISO's peak load to adjust for grid size. This figure is likely of greater value to the ancillary services requirements analysis performed as part of this study, as wind development relative to overall balancing authority size is an important metric that will be discussed further in the Market Structure Analysis below.

Figure 3.3 – 2011 Wind Interconnection Queues Normalized by 2022 Peak Load



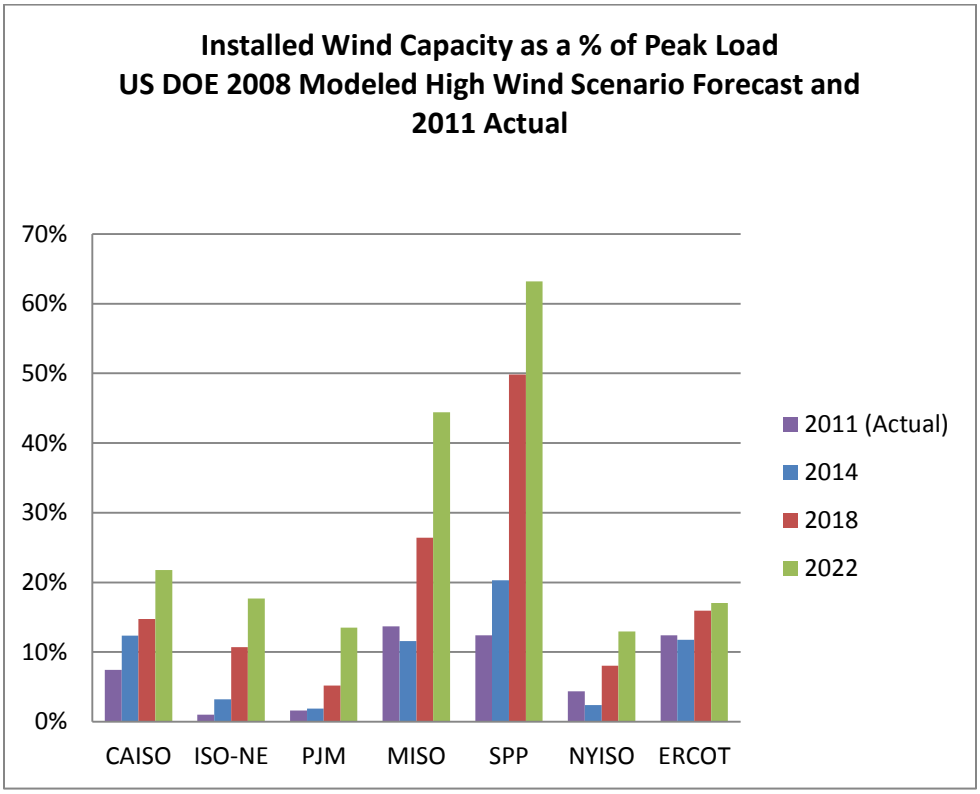
Approach #2: Review of Energy Modeling Efforts by Industry Experts

An alternative method of analysis for evaluating the expected wind growth in a given market is to review the energy modeling and forecasting performed by industry experts. As an example of this approach, our team reviewed the results of the 2008 Department of Energy (DOE) led initiative known as *20% Wind by 2030*. This report was prepared by the DOE in collaboration with industry, the National Renewable Energy Laboratory and the Lawrence Berkeley National Laboratory, and explored a modeled energy scenario in which wind could most cost-effectively produce 20% of U.S. electricity by 2030[xxxiv].

While certainly an ambitious national wind penetration target, as in Approach #1, for the purposes of this analysis, the actual quantity of forecasted wind capacity is not what it will be – rather it is the differences in the relative expected growth in installed wind capacity across markets. Using the results from the *20% Wind by 2030* scenario analysis, Figure 3.4 below demonstrates projected wind penetration levels as a percentage of peak load for the ISO markets previously shown above during 2014, 2018 and 2022[11].

[11] Where substantial discrepancies existed between forecasted wind levels in the 2008 report and actual installed capacity as of 2011, the 2011 actual figures provided by AWEA were used as the baseline and the

Figure 3.4 – Projected Regional Wind Penetrations (U.S. DOE 2008 Analysis)



Many of the key inputs and assumptions that go into performing the analysis conducted by the U.S. DOE and their collaborators may no longer be accurate four years later (due to natural gas prices, overnight capital costs of wind installation, etc.), nevertheless the results from this study convey a similar message to the findings in Approach #1: when considering wind development in relation to overall electric size of a power system, MISO and SPP are expected to be the most rapidly growing U.S. wind markets in the future.

3.2 Market Structure Analysis

In addition to identifying markets with high levels of wind penetration, our qualitative framework suggests a review of a number of characteristics of balancing authorities that are predictive of the extent to which large wind ramps are likely to pose significant strain on local grid operations[12].

underlying growth rates from the DOE report were used to grow the portfolio of installed wind capacity for future years.

[12] Readers are additionally referred to the "System Evaluation Tool" first conceptually introduced by Gramlich and Goggin in 2008, and expanded upon by Milligan, Kirby, Gramlich and Goggin in 2009 – which similarly

3.2.1 Balancing Authority Size

As a general rule, larger balancing authorities with a larger geographic footprint and higher peak load will be better able to accommodate high wind penetration levels (and associated wind down-ramp concerns) than smaller control areas. Larger power systems will typically have a larger, more diverse set of generation sources, reducing they system's reliance on any one subset of generators and thereby reducing the vulnerability to wind down ramps. Moreover, larger balancing authorities are more likely to have a greater degree of interconnection with neighboring balancing authorities and more robust transmission with the balancing authority, a characteristic that favors wind integration discussed further below.

A large balancing authority will clearly be less impacted by a wind down ramp of a given number of megawatts than a smaller balancing authority (in terms of electrical size) facing a down ramp of the same magnitude. While of course by occupying a larger geographic area allows a bigger balancing authorities to have higher total amounts of installed wind capacity, the marginal impact of a given wind farm, or a given megawatt of wind capacity, is more significant in a smaller balancing authority. **As a result, larger balancing authorities will likely require less in terms of provision of ancillary services on a per MW of wind basis[13].**

3.2.2 Transmission Network

A more robust and interconnected transmission network reduces the risk associated with relatively large amounts of wind dropping offline in a wind down-ramp, and thus decreases the overall amount of load-following ancillary services required per MW of wind capacity. A more interconnected system offers grid operators more options in allowing increased power to flow within the system to make up for wind power shortfalls[14]. In addition to the quantity of physical interconnections between the nodes in the system, congestion on the lines must also be considered as a congested line that cannot take on increased power is of equivalently little value to a balancing authority seeking to ramp generation in the wake of a wind down-ramp.

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proposes a set of metrics by which to evaluate a power system's likely capacity to accommodate high wind penetration levels. Our framework, while relying on much of the same research as did these authors – as well as other works of these authors themselves, was built prior to our discovery of their explicit "System Evaluation Tool". Unsurprisingly, our Market Structure Analysis framework and Gramlich, et al's System Evaluation Tool contain substantial overlap.

[13] The characterization of large versus small balancing authorities discussed herein is inextricably linked with and related to a number of the other metrics will be discussed below, including transmission, generation assets, wind diversity and load profile.

[14] The same concept holds when these power shortfalls are addressed by reducing load through demand response, as opposed to increasing generation.

Similar to the benefits of having a more robust network within the borders of the balancing authority, a greater degree of interconnection with neighboring balancing authorities reduces the overall requirement for ancillary services procurement within a balancing authority. In addition to physical interconnections, sub-hourly scheduling with neighboring balancing authorities using these interconnection paths allow both balancing authorities to reduce the net variability of their respective wind capacity and share some burden associated with accommodating for down-ramps[xxxv].

3.2.3 Generation Base

A generation base that is not only large and diverse, but that contains an abundance of flexible and fast responding resources will be better able to respond to wind ramps. Flexible gas generation, dispatchable hydroelectric and pumped hydro storage and flywheels, batteries and other energy storage resources all fall into this camp.

Numerous wind integration studies have discussed that faster responding systems reduce the costs associated with integrating intermittent wind generation. Research conducted in California and other western states have found the cost of integrating wind at current moderate levels to be essentially zero, in large part due to the high concentration of fast-responding, flexible gas and large amounts of hydroelectric power available in those states[xxxvi].

3.2.4 Wind Spatial Diversity

The wind output in any two given locations generally becomes less correlated as the distance between these two points increases. On the wind-farm scale, this means that the output of facilities with more turbines that are spread further apart will have "smoother" production (less variability) than wind farms that are smaller and have less distance between the turbines along the borders of the facility footprint. On a larger geographic scale, the combined production from multiple wind farms in different locations in a balancing authority will be less variable (as a percentage of total output) than for each plant on an individual basis[xxxvii]. **Balancing authorities with wind resources and installed wind capacity more narrowly concentrated in one geographic area will be likely to be more impacted by wind down ramps than balancing authorities with an installed wind portfolio that is of similar capacity but that is more geographically diverse.**

3.2.5 Scheduling Granularity

Longer lead times in energy market scheduling (1 hour ahead versus 15 minutes ahead) result in less efficient response to wind ramps. Thus balancing authorities with energy markets that operate

on sub-hourly intervals (as opposed to an hour-ahead market) are able to respond much more effectively to wind ramps that begin to have grid impact on the 10-30 minute time scale. Even with a generation base that can physically respond at a rate that matches the beginning of a typical wind down-ramp, in an hourly market the grid operator will be forced to rely on the more expensive markets of regulation or spinning reserves, rather than energy market bids to meet the generation shortfall.

A 2007 report by Enernex Corporation, for example, documented that in the Pacific Northwest, ten-minute energy markets could reduce the costs of wind integration by 40-60% compared to hourly markets[xxxviii,xxxix]. **A balancing authority with less scheduling granularity, such as an hourly market, is likely to rely more on ancillary services to meet the challenge of balancing wind-down ramps than the same balancing authority with energy market scheduling windows on a narrower time scale.**

3.2.6 Wind Forecast Accuracy and Utilization

High forecasting accuracy, or at least incorporating wind forecasts into system scheduling and operations, reduces the uncertainty in the system and enables more efficient planning and scheduling by grid operators, and a decreased need to procure reserves to mitigate the risk of down-ramps. A 2005 GE Energy study prepared for NYISO and NYSERDA demonstrated, for example, a cost savings of $95 million annual benefit when state of the art wind forecasting is integrated into unit commitment in the New York ISO. "Perfect" forecasting was projected to provide a theoretical additional $25 million in savings[xl]. **Thus, a balancing authority that is unable to incorporate effective wind forecasting into their market scheduling is more likely to over-procure ancillary services to address the concern associated with wind-down ramps.**

3.2.7 Load Profile

Balancing authorities with historically more predictable, "steady" loads are more likely to be less effective at accommodating wind down ramps than balancing authorities already accustomed to and built for dealing with a more variable load profile. A more heterogeneous and/or variable load profile in a balancing authority (caused by cyclical heavy manufacturing loads, drastic seasonal load cycles, etc.) may be better equipped to deal with the risk of wind down-ramps because of existing infrastructure already in place to deal with similar operational challenges[15]. Similar to the benefits

[15] It should be noted that this aspect of our qualitative framework has not been specifically discussed very extensively in the literature, and our presentation of this concept is admittedly subjective. While the premise is certainly reasonable, the authors of this report would be very interested to see more empirical analysis

associated with a larger overall balancing authority, a system with a larger peak load, for example, is more likely to be able to "absorb" greater amounts of wind before becoming strained.

3.2.8 Additional Market Structure Consideration: Demand Response Eligibility for Provision of Ancillary Services

In addition to a market having characteristics that would be predictive of an increasing reliance on ancillary services in the event of high wind penetration, for the purposes of our specific opportunity evaluation another key consideration must be made: does the balancing authority allow participation of demand response resources in ancillary services markets? As discussed in sections 2.4 and 2.5, not every power market considers demand response to be an eligible ancillary service resource, although there is a national trend towards responsive loads increasingly being viewed as viable ancillary service market participants.

3.3 Load Analysis

In addition to developing metrics to assess balancing authorities, our framework also assesses the type of load that would be ideal not only as an effective responsive load but one that specifically can participate in the ancillary services market (in this case, operating reserves). We have created specifications that a third-party demand response provider or utility could use to identify and filter loads that would best handle wind down-ramps in a market. This assessment is based on the following characteristics: load size, load timing, load response speed, load response duration, load response frequency, opportunity costs, and cost of electricity.

3.3.1 Load Size

Responsive loads that are ideal to participate in ancillary services markets as operating reserves must be able to **shed a minimum load amount**. This amount is usually a function of minimum bid requirements that in a given market. The minimum bid amount varies market by market. Our research shows that loads that can shed 500 kW and upwards have historically participated in these ancillary services[xli].

investigating the magnitude of this effect of the historical load profile of a balancing authority and its' relative capacity to accommodate for wind down ramps before making substantial new investments in physical or market infrastructure.

3.3.2 Timing

The time of day and year that loads operate plays a key role in defining ideal responsive loads. Loads **must be pulling from the grid during times of potential wind ramps.** In this situation, loads that operate when wind blows and, even more specifically, when wind down-ramps occur will be able to best to act as operating reserves in ancillary markets.

3.3.3 Response Speed

Another important characteristic of an ideal responsive load to participate as an operating reserve is the amount of time it takes to respond to an operator's request, or **how quickly a load can respond to meet market requirements.** This characteristic will primarily depend on the sophistication of communication control systems the load has in place. With spinning and non-spinning reserves, responsive loads will have to respond within seconds for the former and within ten minutes for the latter.

3.3.4 Response Duration

The length of time a load can respond without sacrificing quality of goods or services is another important characteristic to filter when assessing responsive loads that would act as operating reserves. **Loads must be able to remain shut off or reduced for a sufficient amount of time.** For spinning and non-spinning reserves, the typical duration required is between 10 minutes and two hours.

3.3.5 Response Frequency

A load's response frequency is the number of times (within a given contract – e.g. in a day, year, etc.) that a load will be called upon. Depending on the situation and region, loads that participate in ancillary services markets may never be called on or may be called on many times a year but usually for short durations of time[xlii]. Regardless, to prevent penalization, **loads must be able to respond each time the operator requests demand-side load**.

3.3.6 Opportunity Cost

A major factor from the load perspective about whether or not to participate as a responsive load in an ancillary service market is the opportunity cost that a load faces. Specifically, **the opportunity cost must be low for a responsive load to consider participating in this market**. Opportunity cost in this case includes assessing whether the revenue received from interrupting load during operating hours will be worth the revenue from production and services that may be forgone.

3.3.7 Cost of Electricity

The cost of electricity in a given market will either incentivize or de-incentivize responsive loads from participating in an ancillary services market. In particular, high electricity prices will result in a two pronged benefit to shed load during wind down ramps. First, loads would **save costs** by *not* operating when electricity prices are high. Second, loads would **earn revenue** at the same time by receiving payment for partially or completely shedding load.

3.3.8 Examples of Specific Load Types

Between the regional markets that allow demand response to participate as ancillary services (e.g. ERCOT, PJM, MISO, and NYISO) and pilot programs that have tested demand response in ancillary services (e.g. CAISO, ISO-NE), we have observed a common set of loads that fit the criteria outlined above. Since the cost of electricity and timing of wind ramps will vary from region to region, the common characteristics that make all of these loads potential candidates to act as operating reserves are that they have suitable control systems, can handle being turned off for a short duration of time, and have low opportunity costs in terms of curtailing operations. As mentioned earlier, good control systems will allow the load to respond faster to operator load requests.

Air conditioning, refrigeration, and pumping loads (and hot water heating) are ideal because they coincide with peak spinning reserve prices. Spinning reserves are called on somewhat infrequently and shorter durations, therefore these loads can provide service without really sacrificing business opportunities (e.g. frozen food in industrial storage units will likely not spoil over the requested service time frame).[xliii]

Food Processing

Energy consumption in food processing industry is highly variable by season (especially in fruit and vegetable sector). Wastewater, in particular, in this sector varies in composition and volume depending on product, scale of operation, weather and season and is the key area of operations that may be used as responsive loads for operating reserves.

Wastewater Treatment

Wastewater treatment facilities are subject to a variety of federal, state, and local regulations. Since they need to adhere to regulations at all times, the demand response strategies available to them mainly fall within load shifting rather than shedding. A fast response from these facilities requires real-time control. Many wastewater facilities tend to have sophisticated control systems.

In addition, if wastewater facilities have storage facilities, they can store untreated wastewater and process it when electricity prices are lower. However, storage of some wastewater may not be possible for some industrial facilities if wastewater contain reactive chemical.

Industrial Refrigerated Warehouses

Industrial refrigeration warehouses are excellent candidates because of their massive inherent thermal energy storage potential. Adequate temperatures to maintain product quality are needed. Some products (i.e. packaged frozen goods) are better suited to temperature fluctuations than other (i.e. cooled products. Freezers are more flexible and make up more of the total area of refrigerated warehouses. In the U.S., freezer space comprises 78% of total warehouse area, and cooler space occupies the rest. In addition, these types of loads have a range of control system types.[xliv]

Pumping Loads

Large, municipal water-pumping systems, for example, are flexible loads that could provide reliability services. They can reduce pumping loads for up to a few hours while still delivering the services that water customers demand by letting gravity do the work during non-pumping hours. With control systems and adjustable speed drives, power consumption of pumps could be varied to track power coming from variable sources. Methods for shifting water supply-related electricity demand include policies aimed at reducing water demand during period of constrained electricity supply through measures like time-of-use water rates; or water storage could be used to a greater degree. Water storage can potentially reduce electricity demand during periods of constrained supply and increase demand during periods of excess supply.[xlv]

Heavy Industrial Processes[xlvi]

Thermal energy storage and waste heat recovery systems can be used in heavy industrial processes such as steel and iron mills, paper mills, food processing, and cement manufacturing to reduce a facility's electricity demand during peak hours.[xlvii] The higher the temperature of the waste heat, the more effective it will be for reuse. All of these industries are very energy intensive and create an abundant amount of waste heat that can be used to generate electricity on site to run operations.

4.0 Quantitative Framework

Favorable markets are those found to be lacking sufficient ramping resources or those that would incur sufficiently high balancing costs under the current generation mix or both. Quantitatively,

this assessment aims to determine two market attributes under various wind penetration scenarios: wind ramping behavior and dispatchable generation ramping capability. Wind ramp behavior coupled with a markets generation ramping capability determine a market's technical need for more load-following resources, a need that can be met by a coordinated demand response program. Wind integration scenarios function as stress tests for markets. For markets that signal technical or economic needs, or both, such stress tests represent potentially favorable targets for demand response provides to prepare for their participation as an explicit wind balancing resource or alternative.

4.1 Structural Objectives

The rationale and critique of the market size approach is segmented along two market related study components: wind ramping behavior and dispatchable generation ramping capability. The approach is then explicitly applied to our case study market, SPS, for illustration.

There are three primary attributes that represent the scope and goals of the market size assessment. These attributes determined the quantitative approach taken.

1) *Light and transferable resource* – the modeling for the studies was done in Microsoft Excel and utilized publicly accessible data that is readably available and encompasses all U.S. markets, so to ease accessibility, transparency, and transferability of the research.
2) *Provide first-order assessments for a given market* – the analysis is intended to highlight significant balancing needs that represent a need for significant demand response participation and indicate markets most worth investing resources toward a more robust secondary evaluation.
3) *Utilize a methodology that is relatively intuitive and replicable* – the analysis is framed to facilitate business opportunity discussions and aid in directing due diligence for demand response providers, rather than a technical assessment for enhancing methods on which balancing should be evaluated for scientific purposes.

4.2 Defining Wind Integration Scenarios

An integration scenario is defined as a percent of total installed capacity of a system. For example a "20% scenario" is where the installed capacity of wind is equal to twenty percent of a control area's total nameplate capacity, including the wind under the scenario. It is important to note that each scenario is additive to the wind already installed in a control area.

4.3 Defining Wind Ramps

A wind ramp, for the purpose of this study, is defined as a monotonic change, defined as multiple serial step changes of the same direction, in wind power over a set of temporal step changes of recorded output. A step change is the difference between a record of power output and the prior record of power output along a time series of wind generation data; this difference, or change, can either be positive, negative, or zero. The length of each step change is a function of the defined time interval between singular or averaged data points, therefore a step change can be in seconds, minutes, or hours. Directionality of a set of step changes defines two diametric wind ramp types: a "down-ramp" and an "up-ramp." A down-ramp begins at the point at which a step change in power output shifts from positive to negative (i.e. the inflection point that marks the end of an up-ramp). Symmetrically, the end of a down-ramp ends at the point at which the step change in power output shifts from negative to positive. Consequentially, an up-ramp is defined as the opposite of a down-ramp. Following this definition, a wind ramp can either be comprised of a single step change, sequentially straddled by step changes of the opposite direction[16], or a monotonic change.

These step changes of power output can reflect the wind ramping behavior of a single wind turbine, a group of turbines that comprise a wind plant, or a group of wind plants within a region of interest. Wind ramp behavior is characterized by the ramping directionality, the rate of change in power output, the monotonic duration, and the diurnal and annual persistence and frequency of ramp size[17] classifications. Both the time interval selection, and the number and geographic scope of wind power generation data are important in assessing the wind ramping behavior of a particular regime.

4.3.1 Time Interval Selection

One should expect that the more granular the time series data of wind power generation, the more accurate the assessment of wind ramp behavior[18]. Averaging minute spot data to formulate hourly step changes serves a more accurate measure of the power generated over an hour than hourly spot data alone. Fortunately, it is most common for hourly data to be recorded as an average of a more finite time intervals. The frequency of data collection, however, from SCADA systems, anemometers, and power meters can vary substantially from seconds, to tens-of-minutes, to hours.

[16] Positive and negative
[17] Measured in megawatts
[18] Averaging minute spot data to formulate hourly step changes in power generation serves a more accurate reflection of the power generated over an hour than hourly spot data.

It is therefore best, when manageable, to select sources containing the greatest granularity of wind and power data.

The time interval on which step changes in wind power are calculated has a significant impact on the observed wind ramp behavior. The more finite the time interval used, the more persistent the level of generation over the time of measurement[xlviii]. In other words, wind power generally does not experience large changes in output from one granular moment in time to the next.

Tables 4.1, 4.2, and 4.3, illustrate that the persistence of generation levels for wind power is highly dependent on the time intervals used for step change calculations. The row headings in the tables indicate power levels, as a percent of nameplate capacity, at a time step, and the column headings indicate power levels, as a percent of nameplate capacity, at the next time step. For example, Table 4.1 indicates that for a wind plant operating at fifty percent of its capacity, there is a ninety-nine percent chance that the plant will remain operating at a fifty percent capacity level the following second. Likewise, Table 4.3 indicates that for a wind plant operating at 50% of its capacity, there is a 32% chance that the plant will remain operating at a 50% capacity level the following hour. These tables are from an NREL study of a 103 megawatt plant in Southwest Minnesota[xlix]. Note the dispersion of non-zero numbers as the time interval increases.

Table 4.1 – One Second Power Output Change Probabilities[l]

	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
10%	0.9992	0.0008	0	0	0	0	0	0	0	0
20%	0.0016	0.9967	0.0016	0	0	0	0	0	0	0
30%	0	0.0019	0.9962	0.0019	0	0	0	0	0	0
40%	0	0	0.0026	0.9947	0.0027	0	0	0	0	0
50%	0	0	0	0.0034	0.9928	0.0038	0	0	0	0
60%	0	0	0	0	0.0047	0.9893	0.0060	0	0	0
70%	0	0	0	0	0	0.0065	0.9862	0.0074	0	0
80%	0	0	0	0	0	0	0.0084	0.9792	0.0124	0
90%	0	0	0	0	0	0	0	0.0096	0.9762	0.0141
100%	0	0	0	0	0	0	0	0	0.0102	0.9898

Table 4.2 – One Minute Average Power Output Change Probabilities[li]

	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
10%	0.9928	0.0072	0	0	0	0	0	0	0	0
20%	0.0140	0.9679	0.0181	0.0000	0	0	0	0	0	0
30%	0	0.0212	0.9560	0.0228	0	0	0	0	0	0
40%	0	0	0.0318	0.9385	0.0296	0.0001	0	0	0	0
50%	0	0	0	0.0374	0.9297	0.0328	0.0001	0	0	0
60%	0	0	0	0	0.0405	0.9187	0.0408	0	0	0
70%	0	0	0	0	0	0.0435	0.9161	0.0403	0.0001	0
80%	0	0	0	0	0	0.0001	0.0459	0.9076	0.0464	0
90%	0	0	0	0	0	0	0.0001	0.0359	0.9376	0.0265
100%	0	0	0	0	0	0	0	0	0.0191	0.9809

Table 4.3 – One Hour Average Power Output Change Probabilities[lii]

	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
10%	0.8567	0.1199	0.0167	0.0043	0.0019	0.0005	0	0	0	0
20%	0.2196	0.4947	0.1975	0.0697	0.0115	0.0026	0.0018	0.0026	0	0
30%	0.0446	0.2418	0.4252	0.2091	0.0456	0.0228	0.0089	0.0020	0	0
40%	0.0051	0.0803	0.2764	0.3439	0.1771	0.0764	0.0306	0.0089	0.0013	0
50%	0.0033	0.0130	0.1317	0.2114	0.3171	0.1805	0.0959	0.0309	0.0130	0.0033
60%	0	0.0089	0.0302	0.1032	0.2402	0.3132	0.1833	0.0890	0.0249	0.0071
70%	0	0.0038	0.0076	0.0440	0.1033	0.2447	0.2849	0.2237	0.0803	0.0076
80%	0	0	0.0073	0.0054	0.0345	0.0726	0.2341	0.3593	0.2523	0.0345
90%	0	0	0	0.0026	0.0128	0.0217	0.0562	0.1801	0.6066	0.1201
100%	0	0	0	0	0	0.0028	0.0028	0.0212	0.1487	0.8244

Though wind power is stochastic in nature and less predictable than traditional load, it is more reliable at the plant level than conventional thermal generation, which can be taken offline almost instantly if a failure occurs. The wind's greater reliability is a function of both the relatively smooth nature of the rate of change of a wind resource and the comparatively low production component failure impact on plant capacity.[19]

Although wind is generally less predictable than load at any given moment, its persistence is higher. This characteristic of wind power lends credence to the notion that there is greater demand for load-following ancillary services, compared to frequency regulation services, as wind integration increases.

Basing an analysis on a granular time interval not only leads to finding less change from one time period to the next, but also leads to many more, though small, ramp events as directional

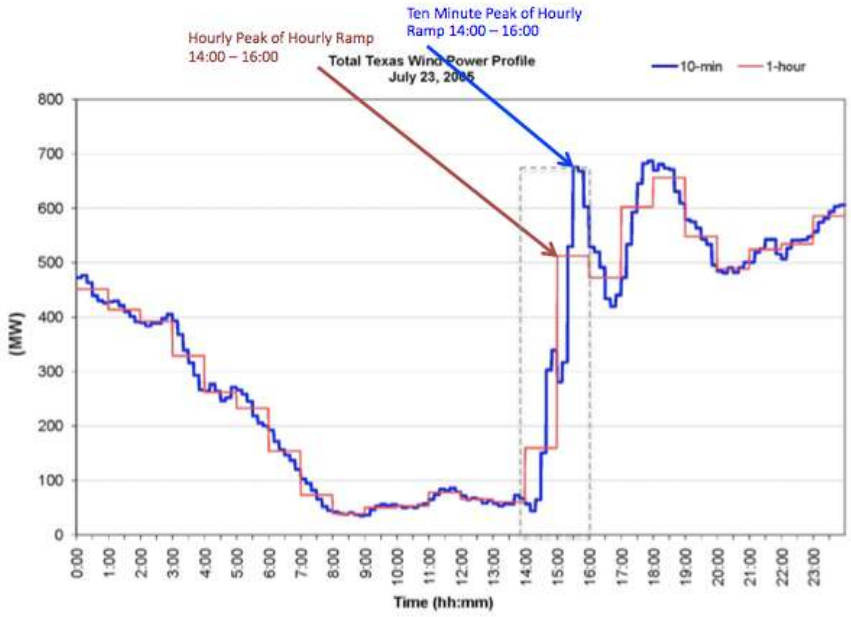
[19] For a thermal generation, a failure of single component of the generation process, a coal pulverizor, for example, will significantly affect the total capacity of a plant. In contrast, a failure of a component of a wind plant, a single turbine, for example, generally has a muted affect on the overall generation capacity of a wind plant.

momentum of change from period is not large. This in turn leads to a micro-view of wind generation that is less suited for the economic response window and duration time of demand side management program; it is not a wind behavioral view that lends itself well to evaluating the load-following requirements of wind generation. It is therefore best to use an hourly measure of change, preferably arrived at through hourly averages of second or minute data, to assess demand response as a suitable resource for managing wind ramps.

Time Interval Selection - Limitations

In choosing averaged hourly data the absolute maximum values of ramps can be missed by the average smoothing of data points comprising the hourly step change. Figure 4.1 is taken from a recent ERCOT ramping behavior study[liii] and serves as an illustration; note that by using hourly average data the absolute peak of the up-ramp occurring between 14:00 and 16:00 on July 23, 2006 is missed. In the same way the absolute minimum of a down-ramp is subject to exclusion. Although this error can be addressed by incorporating more granular time intervals within hourly monotonic behavior, the approach used in this study for manageability defines ramps solely on average hourly data. Therefore the calculations of ramp sizes may be underestimated.

Figure 4.1 – Ten Minute Ramp versus Hourly Ramp Intervals[liv]



4.3.2 Scope Selection

Wind is not a uniform resource; terrain and working conditions have a substantial impact. Measuring step changes of the power output of an individual turbine only captures the ramping

behavior of a very small component of a wind plant. Wind plants are comprised of tens to hundreds of turbines, sometimes stretching miles. As plant size grows, so does the diversity of terrain and working conditions of turbines. Therefore, increasing the size of a wind plant does not increase the magnitude of wind ramps linearly. Among a fleet of turbines in a relatively discreet area, a down-ramp of one turbine is likely to be offset by an up-ramp of another. This is particularly true under short time intervals, as reflected previously in Tables 4.1 and 4.2. As time intervals increase, however, the directionality of ramp behavior becomes more persistent as wind conditions are allowed time to pass through larger areas, affecting a fleet of turbines more uniformly over time[lv].

Following this logic, the greater number of wind plants that are sufficiently separated geographically will yield a ramping behavior that is more true to that which will be experienced by a balancing authority's grid operations for a given wind integration scenario.

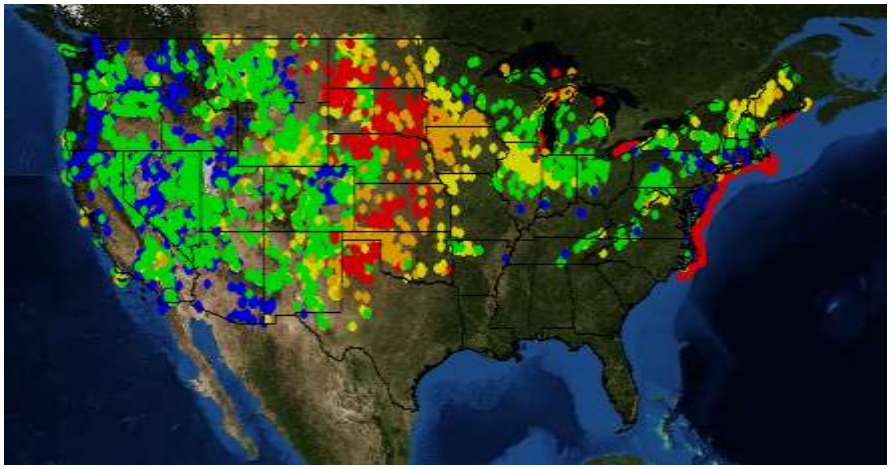
4.4 Wind Ramp Study Approach

As mentioned previously, wind behavior is location specific; as such a wind study based on a wind data set from one location cannot be interpolated as a uniform assessment of a markets wind ramp behavior.

4.4.1 Wind Data Source Selection

Wind data in our study was acquired from NREL's Wind Integration and Transmission Study, specifically we acquired data from the Eastern Wind Integration and Transmissions Study (EWITS) website[lvi]. It is important to note that the EWITS land-based wind data is not reflective of existing wind plants. Rather, the study is comprised of recorded ten-minute wind speed data for 1,326 wind sites, which are then independently extrapolated to an optimal plant capacity size and turbine specification arrangement to derive power output for each wind site over a three-year period (2004-2006). The NREL's data sets are well documented, sufficiently cover all U.S. wind markets and are free and publically accessible; Figure 4.2 illustrates the market coverage of the wind data available by wind class.

Figure 4.2 – NREL Wind Integration Study: Map of All Wind Study Locations by Capacity Class[lvii]



Wind Data Source Selection – Limitations

There are three primary limitations in using EWITS data.

First, intra-spatial diversity of a plant is absent. Because EWITS extrapolates a wind plant's power generation from wind data collected from a single location, every turbine comprising an EWITS site is assumed to experience the exact same wind conditions for any given ten-minute interval. Therefore ramp-canceling conditions that come from spatial diversity within an array of turbines is not captured. By using averaged hourly data, however, this becomes less a concern for the reasons previously stated[20].

Second, the EWITS data only covers three years, the most recent year being 2006. This not only limits the statistical sample size, but also prevents the ability to tie the wind generation to the most recent generation load for a given system. This disconnects any correlation between hourly load demands for a given regime and the wind generated for a given hour for years after 2006. This becomes an issue when a control area's generation ramping capability is assessed against wind ramps from a different time series. This problem compounds in that it prevents the value of wind forecasts in the regimes balancing program from being inherently imbedded in a balancing authority's dispatch capacity for a given hour in anticipation of an observed wind ramp derived from the EWITS data.

[20] See section 4.3.2 Scope Selection

Third, the EWITS data assumes that the optimal wind turbine technology is adopted based on the characteristics of a site. These are historical assumptions and do not necessary reflect what is likely to be installed in the future as wind technologies and conditions change.

To combat the historical nature and sample size constraint of EWITS data one could stochastically extend wind ramping behavior. Because wind is both seasonal and diurnal it is path dependent, and therefore an autoregressive, mean reverting, fit must be determined. Further, because wind patterns vary from one location to the next, a site-specific regression order must be determined. While stochastically extending wind ramping behavior would alleviate some of the data limitations, doing so would add significant complexity, limiting the transferability and usage of the approach[21].

4.4.2 Wind Ramps of Interest

All ramps are defined under the methodology outlined in Section 1.1. The time interval selected was hourly based on the rational stated in Section 1.2. As such, each ten-minute set EWITS data that comprised each hour of each year for each site selected was averaged. Wind ramp behavior is assessed as ramps placed on a control area and therefore the averaged hourly data for each site year is summed to comprise a system total for each hour of each year. From this hourly data, hourly system step changes are calculated.

In line with the objective to provide a first-order assessment, the focus of the analysis is on "large" monotonic ramps. Each large monotonic ramp is defined as containing one or more system of hourly step changes, in absolute terms, which are at least three standard deviations from the three-year average absolute hourly system step change[22]. This definition is, for the most part, reflective of that used by a recent NREL analysis ramping behavior within the Electric Reliability Council of Texas's (ERCOT) control area.[lviii]

Conventionally, balancing wind up-ramps necessitates a reduction of dispatchable[23] generation. Thermal generation plants are complicated, expensive, and can require significant start-up and shut-down time. Further, thermal generation plants designed to serve as baseload generation are particularly economically sensitive to requirements that deem they operate at less than optimal operating conditions. Therefore, a large wind-up ramp can in theory create very costly balancing protocols. Further, shutting down a plant in an extreme example creates a threat to grid stability if the plant's generation capacity, which is no longer dispatchable within a short time frame, is

[21] See section 4.1 Structural Objectives
[22] Averaged from EWITS data years 2004 through 2006
[23] Defined here as nuclear, hydro, coal, and natural gas powered generation

required due to sudden wind drop. In practice this generally is not a primary concern for two reasons. First, dispatachable generation is usually operating well above its minimum stable output for efficiency reasons[lix]. Second, it is likely to be more economic for the balancing authority to curtail the wind generation sufficiently to prevent such costly and unstable reductions of dispatchable generation in a system.

Large wind down-ramps, on the other hand, require dispatachable generation to have sufficient ramp up capacity to compensate for the lost wind power. Because online generation capacity is generally operating closer than not to its nameplate capacity limits a control area's capacity to sufficiently increase generation to reliably cover for lost wind generation. A large wind down-ramp therefore can exceed a system's ability to compensate for a sudden or persistent drop in wind output and require very costly contingencies to prevent a system failure.

It is for this reason that large down-ramps, not up-ramps, are of primary focus for a first-order market needs assessment.

4.4.3 Wind Ramp Behavior Assessment

There are a number of ways in which identified wind down-ramps can be evaluated and behavior's communicated. In order to best facilitate market opportunity discussions and first-order decisions, statistical outputs were pared down to those most relevant for assessing wind down-ramps with respect to available load and responsiveness under a demand side management program; see Figure 4.3 for metrics used.

Figure 4.3 – Ramp Behavior Assessment Matrix

Attribute / Aggregation	Overall Summary	Seasonality	Time of Day
Frequency	Total number of large wind down-ramps	Percent of total large down-ramps by season	Percent of total large down-ramps by six-hour blocks, GMT
Response (MW/Hour)	Average rate of change of large wind down-ramps	Average rate of change of large wind down-ramps by season	Average rate of change of large wind down-ramps six-hour blocks, GMT
Persistence (Hours)	Average duration of large wind down-ramps	Average duration of large wind down-ramps by season	Average duration of large wind down-ramps by season by six-hour blocks, GMT
Size (MW)	Average amount of power displaced by large wind down-ramps	Average amount of power displaced by large wind down-ramps by season	Average amount of power displaced by large wind down-ramps by six-hour blocks, GMT
Constraints	Maximum large wind down-ramp behavior; ramp rate, duration, and size	Maximum large wind down-ramp behavior; ramp rate, duration, and size by season	Maximum large wind down-ramp behavior; ramp rate, duration, and size by six-hour block, GMT

Because market sizing is meant to reflect multiple wind penetration scenarios the sizing component is generally communicated as a percentage of maximum wind power output for a given scenario. This provides a leveled metric. Further, each scenario's wind output is simply a reflection of the hourly averaged raw EWITS data as a percent of accumulated nameplate capacity. Therefore, nameplate capacity is modulated to achieve a desired wind market penetration scenario. As a result, the effect on the duration and temporal placement of wind ramps is unchanged from one scenario to the next. Only the magnitude of wind ramp rates and wind ramp size are affected on a megawatt basis among wind integration scenarios.

4.5 Defining Dispatchable Generation Ramping Capability

The ramp capability of dispatchable generation is defined as the maximum rate at which a disputable power plant[24] can increase or curtail its production of megawatts over a defined time interval. Therefore there is both a defined ramp down (curtailment) capability and a defined ramp up (increase) capability of a plant. Further, the directionality of the ramping capacity is determined by the direction of a plant's step change in load from one period to the next. Therefore a plant's ramp down capacity is calculated when the next period's plant load is less and a plant's up ramp

[24] Defined here as nuclear, hydro, coal, and natural gas powered generation that is currently online

capacity is calculated when the next period's plant load is greater. As such under this approach, a plant cannot have ramp up and ramp down capacity for a given period.

It is important to note that under this definition, the time intervals measured exclude those found in periods in which one or more of a power plant's generators is either starting up or shutting down. These exclusions are made because changes in generation during start-up and shutdown periods were deemed changes under unstable operating conditions.

To determine a power plant's ramping capability over a particular period of time, however, requires defining the floor and a ceiling of a plant's generation capacity. A plant's generation floor is derived from a plants minimum stable power output; therefore it excludes power generated during periods in which one or more generators of a plant are in the process of shutting down. The ceiling, for this study, is simply the nameplate capacity of a power plant. The plant's current stable operating condition is then placed within this floor and ceiling to calculate both it down-ramp and up-ramp capability for a given time interval.

A power plant's up-ramp capability is calculated as the minimum value between the plant's maximum ramp rate and the difference between its current operating power output and its nameplate capacity. For example, a power plant that is currently producing 250 megawatts on January 1st at 13:00 and has a nameplate capacity of 300 megawatts and maximum stable ramp rate of 100 megawatts per hour would have a ramp up capacity of only 50 megawatts between 13:00 and 14:00.

Similarly, a power plant's ramp down capacity is calculated as the minimum value between the plant's maximum ramp down rate and the absolute difference between its current operating power output and its minimum stable output. For example if the same power plant as in the previous example is producing only 100 megawatts on January 2nd at 13:00 and has a maximum stable curtailment rate of 200 megawatts and a minimum operating capacity of 25 megawatts it would have a maximum down-ramp capability of only 75 megawatts between 13:00 and 14:00.

When defining wind ramps it is important to consider the time interval selection, finding that hourly averaged data was more relevant than smaller time intervals[25]. Conversely, because we are seeking maximum capabilities, the more finite the time series under evaluation, the more

[25] See section 4.3.1 Time Interval Selection

advantageous it is to assessing a balancing authority's generation capabilities and load requirements.

4.6 Dispatchable Ramping Capability Study Approach

Because balancing authorities will economically take on all wind power that is generated when it is generated, wind producers are generally price takers in markets. This characteristic, along with wind's inherent stochastic nature equates wind power generation to negative load. That is, when the wind is blowing, it offsets a system's load demands on the dispatched generation. A wind down-ramp can occur simultaneously with a decrease in load demand, reducing a down-ramp's impact. Conversely, a wind down-ramp can occur simultaneously with an increase in load demand exacerbating its impact to the system. It, therefore, it is the net effect of load and wind power change that determines the ramping requirement needs of a balancing authority.

The purpose of this study is to assess the likelihood that a balancing authority's current fleet of dispatchable generation will not have ramping capability to compensate for wind down-ramps effects while accounting for the net effects of load demands. Both wind and load data must therefore be paired to determine the ramping requirements under various wind penetration scenarios.

4.6.1 Dispatchable Generation Data Selection

Generation data was acquired from the US Environmental Protection Agency's (EPA) Air Markets Program Database[lx]. Power plants generally hold their production data propriety. The EPA provides sufficient data, however, to construct a general assessment of a market's ramping capabilities. The data that is accessible reflects hourly load (generation), by thermal generator, by power plant, and by control area.

Dispatchable Generation Data Source Selection – Limitations

There are two significant limitations of the EPA data.

First, it only captures load of thermal, fossil fueled, generators. This is a big limitation when assessing the ramping capabilities of a control area that holds significant hydroelectric resources or nuclear power. Of the two resources, nuclear is less of a concern for this study because it serves as base load resource and operates near its nameplate capacity, thus it inherently has very limited ramping capability. Hydroelectric resources, on the other hand, can serve as both a frequency

regulation and load-following resource with very fast ramp rates. For areas with substantial hydroelectric resources such as the Pacific Northwest, the use of EPA data will lead to a substantial underestimation of a regimes ramping capability.

Second, the EPA data is hourly. Recall, because ramp rates are being evaluated, obtaining the most finite time series data available is best[26]. Unfortunately, hourly data is as finite as it gets in the public domain. Hourly load data can significantly mask the maximum ramp rates of a thermal power plant. For example, from hourly data we may be able to determine that the maximum ramp rate of a power plant is 100 megawatts over an hour. We cannot, however, decipher whether those 100 megawatts were produced within the first ten minutes of the hour to meet the load requirement and whether the load requirement was significantly higher during the hour.

We can safely assume that the generation data available leads to an underestimation of the total ramping capability of a control area. As such, when evaluating a market it is important to not place much emphasis on wind down-ramps that marginally exceed a market's ramping capability.

4.6.2 Ramping Capability Assessment

There are three approaches taken to assess the extent to which additional load-following resources may be required under various wind penetration scenarios for a given market.

The first approach is to overlay the time series of the large wind down-ramps identified under the wind ramp study to the thermal generation ramp capability. The down-ramps identified to exceed a market's ramping capability can be explicitly identified along a matching time series, and the number and size of ramping capability deficits can then be derived.

There is a challenge with this approach, however, in that the years of wind data (2004 - 2006) are not ideal for identifying a market's current generation capabilities. Therefore the EWITS wind data is inherently disjointed from the current (2010) dispatch data. As mentioned previously this mismatch removes correlation between load and wind that may exist. Further it removes value of wind forecast inherent in the load data supporting current penetrations of wind in a market. Finally because a control area's ramp up capability is only quantifiable when load step changes are positive, this approach (and the subsequent approach) only evaluates wind down-ramps that are coincidentally moving in the opposite direction of load. For a market with a low wind base, however, this limitation will not be affected much. Any serial time assessment of ramping capacity

[26] See Section 4.5 Defining Dispatchable Ramping Capability

for provided wind scenarios, however, continues to assume away the ability to forecast wind. Therefore, this approach generally provides an optimistic assessment of a market capacity needs for large ramps moving opposite load.

The second approach is to assume a rational wind forecast error. Under this study, the impact of the forecast error was assumed to have symmetrical probability of forecasting over and under wind load; a 10% forecast error, therefore would equate to a 5% error rate of underestimating wind down-ramps. Under this approach, wind down-ramps that exceed the ramping capability of a market, operating under a generation dispatch schedule that is at fifty-percent the forecast error of actual wind load, can be quantified. Because the forecasted error here is assumed to operate as a perfect step function in tandem with wind, it eliminates any compounding forecast error effects from one period to the next; this approach provides a pessimistic assessment of the market.

The third approach is to evaluate the cumulative probability function (CDF) of a markets ramping capability against the CDF of hourly wind step changes over the hours of a year for each wind integration scenario. Under this approach, all step changes in wind are evaluated not just those comprising large down ramps. This approach assumes that the largest step change in wind is matched with the greatest instance of ramp capability of the market; all temporal dependence between load demand and generation is removed. Although this approach provides a relatively conservative snapshot of a market's ramp capability deficit it represents a compromise between the two prior approaches in that it includes all step changes in wind and load. This approach is reflective of that outlined in the 2005 NREL case study[lxi].

Undertaking all three approaches is a reasonable way to triangulate a market's need for additional load-following recourses under various wind integration scenarios.

5.0 SPS Case Study

5.1 SPS Wind Penetration Analysis

We estimate current SPS net wind penetration to be approximately 7%[lxii][27]. Rather than endeavoring to forecast specific wind penetration levels for the balancing authority going forward, we performed a scenario analysis, evaluating wind penetration levels reflecting the current level as a baseline, as well as 15%, 20%, 30% and 40% penetration.

[27] 980 MWs installed with 529MWs available for export

5.2 SPS Market Structure Analysis

5.2.1 Balancing Authority Size

SPS is located within the Regional Transmission Organization (RTO) known as the Southwest Power Pool (SPP). While many of the other ISOs and RTOs functionally act as the balancing authority for nearly all of the geographic territory within the ISO/RTO boundary, SPP's regional footprint contains 16 distinct balancing authorities[lxiii]. As one of these balancing authorities, SPS covers much of the Texas Panhandle and a small area of Eastern New Mexico. While not necessarily considered to be a small balancing authority, compared to other large wind markets such as the balancing authorities of ERCOT and MISO, SPS is on a much smaller scale. See Table 5.1 to compare the relative electric size of these markets with SPS, and SPP overall.

Table 5.1 – ERCOT, MISO, SPP, and SPS Size Comparison

ISO / Balancing Authority	Approximate Peak Load (GW)	Approximate Installed Generation Capacity
ERCOT[lxiv]	66	71
MISO[lxv]	116	137
SPP Total[lxvi]	43	51
SPS[lxvii]	5	7.5

Given this much smaller scale, SPS is likely to be more vulnerable to the impact caused by large wind-down ramps than would a balancing authority of a larger size.

5.2.2 Transmission Network

SPS finds itself located in a relatively constrained area of the overall SPP transmission network, and as a result has limited capability to trade power with other SPP members[lxviii]. Increased interconnection with neighboring balancing authorities and an enhanced ability to import and export power would reduce the impact of large wind down-ramps. Conversely, because of this relative "island" status, the demands for the ancillary services that provide reliability assurance are directly increased to a level likely that would be unnecessary in a more interconnected scenario.

5.2.3 Wind Spatial Diversity

The wind resources in the SPS balancing authority are relatively well distributed throughout the geographic footprint of the control area. Compared with other balancing authorities in the region,

the existing wind farms in SPS include a number of smaller facilities distributed throughout SPS, in contrast to the alternative scenario of having a smaller group of larger wind facilities concentrated within a close range. The effect of this distribution of wind generators is that it tends to dampen the impact of large wind ramps[lxix]. Further discussion of these specific spatial diversity effects is included in the discussion of our quantitative wind modeling results for SPS below.

5.2.4 Scheduling Granularity

Currently, SPP (and SPS specifically) does not have a centralized energy market. Bilateral energy transactions are conducted on a day-ahead basis, and SPP manages an Energy Imbalance Services (EIS) market which functions as a real-time energy market. While most RTOs and ISOs dispatch generation within their territory on a sub-hourly basis, SPP is a notable exception. Proposed changes that will be discussed in greater detail below suggest that this dynamic will shortly be changing, however at least at present the market structure within SPP likely leads to less system flexibility relative to SPP's peer ISOs and RTOs[lxx].

5.2.5 Generation Base

SPS lacks hydroelectric generation assets, and does not presently employ the services of any fast responding energy storage facilities. As demonstrated in Table 5.2 below, the balancing authority relies on two base load coal facilities and a number of gas-fired resources. The average age of these facilities is approximately 34 years. The lack of fast responding, non-fossil resources and the relative age of the natural gas plants shown below suggest that SPS' ability to quickly ramp up resources in response is likely less efficient than other similar sized balancing authorities endowed with a higher concentration of newer plants and/or a greater diversity of generation technologies.

Table 5.2 – SPS Generation Base

Plant Type	Nameplate Capacity (MW)	Capacity Factor	Age (Yrs)	Heat Rate (Btu/KWh)
COAL	1,080	77%	34	11,024
COAL	1,136	72%	29	10,386
GAS	254	68%	13	7,635
GAS	521	52%	13	7,909
GAS	496	42%	40	10,835
GAS	434	35%	60	11,471
GAS	476	31%	48	11,138
GAS	519	31%	32	11,550

GAS	213	28%	42	10,899
GAS	107	23%	31	8,012
GAS	21	20%	22	8,500
GAS	49	10%	58	25,914
GAS	151	10%	40	12,173
GAS	340	5%	13	11,717
GAS	25	1%	38	18,045
GAS	16	1%	35	17,844

Further discussion of the generation base in SPS will be conducted in great detail in the Quantitative Analysis section, including an assessment of the ramping capability of the balancing authority at various wind penetration levels.

5.2.6 Wind Forecast Accuracy and Utilization

SPP does not currently utilize a centralized wind forecast, with wind forecasting specifically the responsibility of individual balancing authorities (such as SPS) and wind generators themselves[lxxi]. Lack of centralization and information sharing across the region suggests potential sub-optimal coordination and integration of wind forecast data into generation scheduling, which particularly at high wind penetration levels may increase the likelihood of significant and potentially costly ramp events.

5.2.7 Additional Market Structure Consideration: Demand Response Eligibility for Provision of Ancillary Services

At present, SPP does not operate a centralized ancillary services market. Ancillary services are procured and managed by the individual balancing authorities within the SPP footprint. Demand response is not currently considered an eligible resource for provision of ancillary service market service. Given the impending changes in the regions market rules however (discussed below), improved integration of responsive load as a resource eligible for ancillary service provision is currently undergoing consideration in SPP per the requirements imposed by FERC Order 719.

5.2.8 Outlook Changing with SPP "Integrated Marketplace" on the Horizon

On February 29, 2012, SPP formally filed tariff revisions with FERC proposing implementation of a new market structure for the region, referred to as the Integrated Marketplace Program. Several of the key market structure changes to be included in this comprehensive overhaul of the region's

electricity market will significantly alter the new market's "performance" on the aforementioned metrics in this market analysis framework. In particular, one of the most significant expected changes will be consolidating all SPP territory into one balancing authority. Even without any of accompanying changes to market rules and operations expected to bring SPP in line with more sophisticated centralized markets such as PJM or MISO, simply by substantially increasing the balancing authority boundary, certain key issues for wind integration and down–ramp mitigation discussed above in Balancing Authority Size, Wind Spatial Diversity, Transmission Network are likely to be improved upon. SPP anticipates the new marketplace to become finalized and begin operations by March 1, 2014[lxxii].

5.3 Load Assessment within SPS

We first dissected SPS into counties to identify business establishments within the region. Publicly available and specific data for establishments within the SPS region are nearly non-existent. The most comprehensive database of business and industries in the U.S. is the U.S. Census Bureau. Using 2009 Census Bureau statistics, we surveyed every county to find establishments that fit our load criteria. Specifically, we used NAICS (North American Industry Classification System) codes, which range from two to ten digits as they increase in the level of detail provided, by the United States Census Bureau to sort through businesses within each county. However, NAICs codes, as a function of the census, become less specific, the more specific the geography (i.e. from the nation to state to city to county level, the less data – or digits - is available regarding establishments). For examples, more detailed information (e.g. electricity consumption) is only available for establishments that fall under the manufacturing industry code 31-33. The data that would be most useful, with ten digit codes, would provide more insight into the operations on site. The Census Bureau deliberately increases ambiguity of establishments within more specific regions in order to protect privacy and competition.

Consequently, our load analysis was a result of assumptions based on load participation in previous markets and pilot programs in addition to a generalization of electricity consumption from the manufacturing sector. Specifically, we used the electricity consumption and number of establishments in Texas, all of which were from the 2002 Economic Census Manufacturing Industry Series, to find the average electricity consumption per establishment. Since our initial calculations are assuming iron and steel mills in addition to industrial gas manufacturing establishments that are running throughout the year (i.e. 8,760 hours per year), we used a range of capacity utilization factors, ranging from100% to 25% to approximately adjust for other industries and the size or

electricity consumption range of iron and steel and industrial gas manufacturing facilities (see Table 5.3). We used the electricity consumption amounts as a proxy to estimate how much each of the load groups identified may be able to shed in a given year.

Table 5.3 – Electricity Consumption of Loads in SPS[28]

		Number of Establishments		
Capacity Utilization	**kW per Establishment**	Refrigeration	Manufacturing	Commercial and Public Buildings
		100	**93**	**270**
100%	17,584.22	**1,758,421.79**	**1,635,332.26**	**4,747,738.82**
75%	13,188.16	**1,318,816.34**	**1,226,499.20**	**3,560,804.12**
50%	8,792.11	**879,210.89**	**817,666.13**	**2,373,869.41**
25%	4,396.05	**439,605.45**	**408,833.07**	**1,186,934.71**

5.3.1 Ideal Loads in SPS for Demand Response Participation in Ancillary Services

After identifying specific facilities/business operations in counties within Texas and New Mexico in the SPS balancing authority within SPP based on general responsive loads used historically in other markets and pilot programs in addition to identifying new business operations specific to the SPS region that could apply/fit the load characteristics that are ideal would ideal to participate as ancillary services, we grouped each in three separate buckets (heavy manufacturing, industrial refrigeration, and commercial and public buildings), and assessed each bucket based on the qualitative framework we developed (described above in the Load Analysis in Section 3.3).

[28] Load Size is a kW/establishment estimate calculated using average electricity consumption and estimated numbers of establishments published in the 2002 Economic Census for the Manufacturing Industry (specifically, Iron and Steel and Industrial Gas Manufacturing) in Texas.

Table 5.4 – Load Types Identified in SPS counties by NAICS codes[lxxiii]

	Total Establishments
Refrigeration	
31211 Soft drink and ice manufacturing	4
312113 Ice manufacturing	2
31141 Frozen food manufacturing	1
311412 Frozen specialty food manufacturing	1
42442 Packaged frozen food merchant wholesalers	7
424420 Packaged frozen food merchant wholesalers	7
4244 Grocery and related product merchant wholesalers	78
TOTAL	**100**
Manufacturing	
3311 Iron and steel mills and ferroalloy manufacturing	4
33111 Iron and steel mills and ferroalloy manufacturing	4
331111 Iron and steel mills	4
325 Chemical manufacturing	47
3251 Basic chemical manufacturing	20
32512 Industrial gas manufacturing	7
325120 Industrial gas manufacturing	7
TOTAL	**93**
Buildings	
6113 Colleges, Universities, Professional Schools	7
61131 Colleges, Universities, Professional Schools	7
72111 Hotels (except casino hotels) and motels	211
622 Hospitals	45
TOTAL	**270**

Heavy Manufacturing

We identified at least 93 facilities within the region that fall under this category. We assumed this number to be the minimum number of facilities because of the limited or lack of data available for some counties. Examples of operations that fall under the 'Heavy Manufacturing' are chemical manufacturing, steel mills, and industrial gas manufacturing. The key factors that make these ideal responsive loads for operating reserves are that all these business/operations are energy intensive and many, if not all, are likely to be capable of operating cogeneration facilities, where waste heat can be used to fuel operations on site while load is being shed at the operator's request. Although there may not be a large number of facilities, the load size of each facility is significant and would likely meet operating reserve requirements (see Table 5.3 for estimated range of kilowatts each

sector may be able to provide). Most of these loads will be operating continuously or almost continuously throughout the year and will overlap with wind down ramps occur. These loads are also likely to have sophisticated communication control systems in place, which will allow them to respond instantaneously to the operator requests. Finally, these loads will be able to respond more often and for a greater duration as the load interruption will have little or no effect on production due to on-site waste heat recycling, which will continue to fuel operations.

Industrial Refrigeration

We identified at least 100 facilities in the SPS region that would fall under 'Industrial Refrigeration.' In particular, refrigeration warehouses, frozen food manufacturing, and grocery establishments (which use industrial refrigeration). As with all the other facilities we identified, we believe that this is only a baseline estimate such that specific data regarding establishments in the area is limited. There are a significant number of facilities in the region, and therefore potentially a higher amount of load to shed. Industrial Refrigeration loads offer time-of-day flexibility and will likely have little or no effect on products during the duration of operating reserves service the loads will be needed. For example, frozen foods are unlikely to spoil within the time window required for load shedding. This is mainly due to the insulating quality in these facilities that results in improved thermal storage. Finally, these loads may have communication control systems or can have them installed.

Commercial and Public Buildings

We identified a baseline estimate of at least 270 facilities in the SPS region that fall under 'Commercial and Public Buildings' ("C&P Buildings"). Examples of establishments that fall under C&P Buildings include hospitals, universities, and hotels. These facilities provide most or their entire load via heating and cooling systems and can shed load by reducing or curtailing heat (in the winter time) or air conditioning (in the summer time) when called on by the operator with little or no effect on their operations and customer satisfaction. Similar to Industrial Refrigeration facilities, C&P Buildings can adjust the temperature within their facilities and retain most of the heat or cold for the duration of operating reserves service. Although there are a very high number of these facilities in the SPS region, these facilities may not necessarily be able to provide as much load as Heavy Manufacturing and Industrial Refrigeration. In addition, C&P Buildings cannot be called on as frequently or for long durations required of operating reserves such that these businesses will likely be more sensitive to load curtailment.

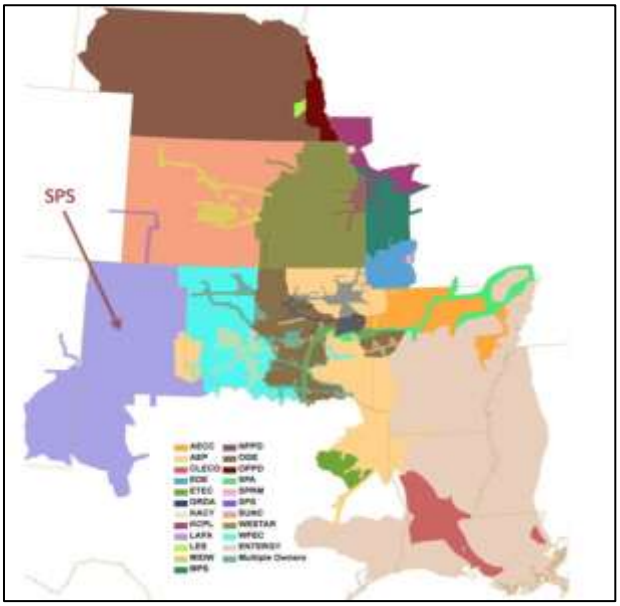
Table 5.5 – Summary of Responsive Loads Identified in SPS

Heavy Manufacturing	➢ Fewer Facilities ➢ High Load Size ➢ Long Duration ➢ High Frequency
Refrigeration	➢ Moderate Number of Facilities ➢ High Load Size ➢ Moderate Duration ➢ Moderate Frequency
Commercial and Public Buildings	➢ High Number of Facilities ➢ Low Load Size ➢ Short Duration ➢ Low Frequency

5.4 SPS Market Size Analysis

Because Southern Power Pool ISO (SPP) does not manage the day-ahead and hourly ancillary services, the individual balancing authorites within the ISO are considered individual markets; see Figure 5.1 map of balancing authorities in SPP. For this case study, the balancing authority under assessment is Southern Power Services (SPS). The quantitative approach on which the case study results are based is described in Section 4 above.

Figure 5.1 – SPP Balancing Authorities Territory[lxxiv]



5.4.1 SPS Wind Data

The SPS case study utilized wind power data from six spatially diversified EWITS defined sites. All of the sites are within SPS territory; see Table 5.6 for site demographic data. All of the sites selected were relatively similar in size as defined by Installed capacity. Further the site locations selected represent those with high probability of being developed based on a recent SPS wind integration study[lxxv], which considered transmission constraints. Figure 5.2 illustrates the geographic locations of the EWITS plants and Figure 5.3 illustrates wind locations under the SPS wind integration study. Evaluating this subset made the analysis more manageable, representing likely wind development, while accounting for the impact of spatial diversity on wind power generation.

Table 5.6 – EWITS Wind Site Demographics

EWITS Site Number	Wind Data Location				Modeled Plant Size		
	State	Longitude	Latitude	Elevation (ft.)	Area (sq.km)	Capacity Density (MW/sq.km)	Installed Capacity (MW)
473	Texas	-101.25	36.15	962	33	8	262
578	Texas	-101.71	36.02	1058	33	8	266
621	Texas	-101.52	35.21	1074	24	12	300
623	Texas	-102.32	35.01	1193	35	8	286
1664	New Mexico	-103.81	33.96	1422	28	18	502
1720	Oklahoma	-101.66	36.65	1023	33	11	377

Figure 5.2 – Map of Wind Site Locations Selected

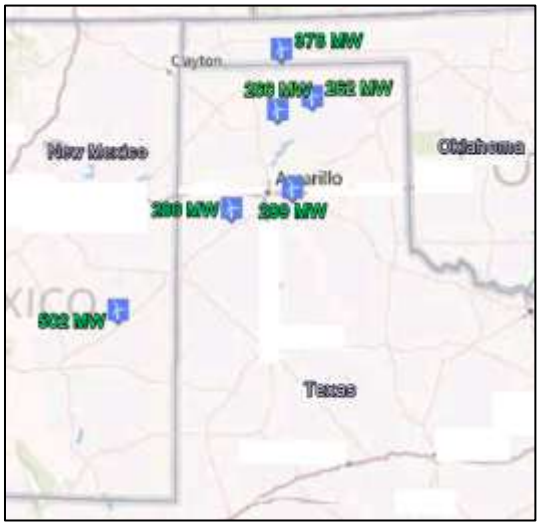
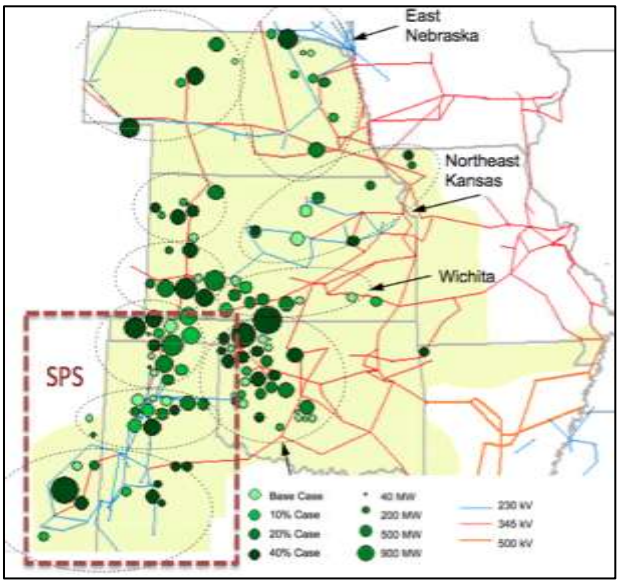


Figure 5.3 - SPP Wind Integration Study Map[lxxvi]



5.4.2 SPS Wind Ramping Behavior

The case study evaluated the ramping behavior of wind under 15%, 20%, 30%, and 40% wind integration scenarios[29]. Ramp size data in the statistic tables that follow have been normalized as a percentage of the maximum hourly power generated over the three year period (2004-2006) that was evaluated. Since each scenario is driven off of the same base data, the percentages do not

[29] For definition of a wind integration scenario, see section 4.2 Defining Wind Integration Scenarios

change from one scenario to the next. See Table 5.7 for the maximum generation under each scenario for power conversions.

The approach used to study the behavior of wind ramps resembles that outlined in a recent study of wind ramps in the ERCOT ISO[lxxvii]. As such, direct comparisons to the study's findings are made when appropriate to provide a comparative point of reference. Further, ERCOT is located adjacent to SPS so the contrasts help illustrate that areas within the geographic sectors of the U.S. may behave very differently.

Table 5.7 – Maximum Hourly Generation by Scenario

Wind Integration Scenario	Max Hourly Generation (MW)
15% Wind	934
20% Wind	1,323
30% Wind	2,268
40% Wind	3,527

SPS has an average hourly step change of 9% of maximum hourly generation and large ramping events are defined as those which contain one or more hourly step changes that are at least 37% of maximum hourly generation. See Table 5.8 for statistics.

Table 5.8 – Wind Step Change Statistics Summary

Average	Std Dev			Maximum MW	
% Max Gen	*sigma (MW)*	*3 sigma (MW)*	*% Max Gen*	*Up Ramp (% Max Gen)*	*Down Ramp (% Max Gen)*
9%	12%	37%	37%	89%	91%

Over the course of the three years of wind power data evaluated, there was an average of 193 large down-ramp events per year. On average, the large down-ramps displaced 57% of the maximum hourly generation and on average the event lasted about two hours and twenty minutes. This size of duration is well suited for commercial and industrial demand response programs. The average down-ramp duration for SPS is significantly less than ERCOT's average large down ramp duration of over five hours. The shorter duration of large down-ramps in SPS is in part due to the more saw-

toothed ramping pattern during the day compared to ERCOT. SPS demonstrates more dominate down ramps from morning until noon (CST) then does ERCOT; see Figure 5.4[30]. This poses greater risk to SPS as more wind comes off-line during business hours. Because there is more load during these hours, however, demand-side management is likely to be a better match as a balancing resource. See Table 5.11 for large down-ramp time-of-day statistics.

Table 5.9 – Large Down Ramps Statistic Summary

Monotonic Large Down Ramps							
Avg No. of Events per Year	*Avg MW (% Max Gen)*	Sigma (% Max Gen MW)	*Avg Duration (Hrs)*	*Sigma Duration (Hrs)*	*Avg % Capacity*	*Avg Ramp Rate (% Max Gen MW/Hr)*	*Sigma Ramp Rate (% Max Gen MW/Hr)*
193	57%	14%	2.30	1.66	29%	34%	18%

Table 5.10 – Large Down Ramp Attribute Maximums

Maximum MW Monotonic Large Down Ramp			
MW (% Max Gen)	*Duration (Hrs)*	*% Capacity*	*Ramp Rate (% Max Gen MW/Hr)*
93%	8	93%	12%

Maximum Ramp Rate Monotonic Large Down Ramp			
MW (% Max Gen)	*Duration (Hrs)*	*% Capacity*	*Ramp Rate (% Max Gen MW/Hr)*
91%	1	91%	91%

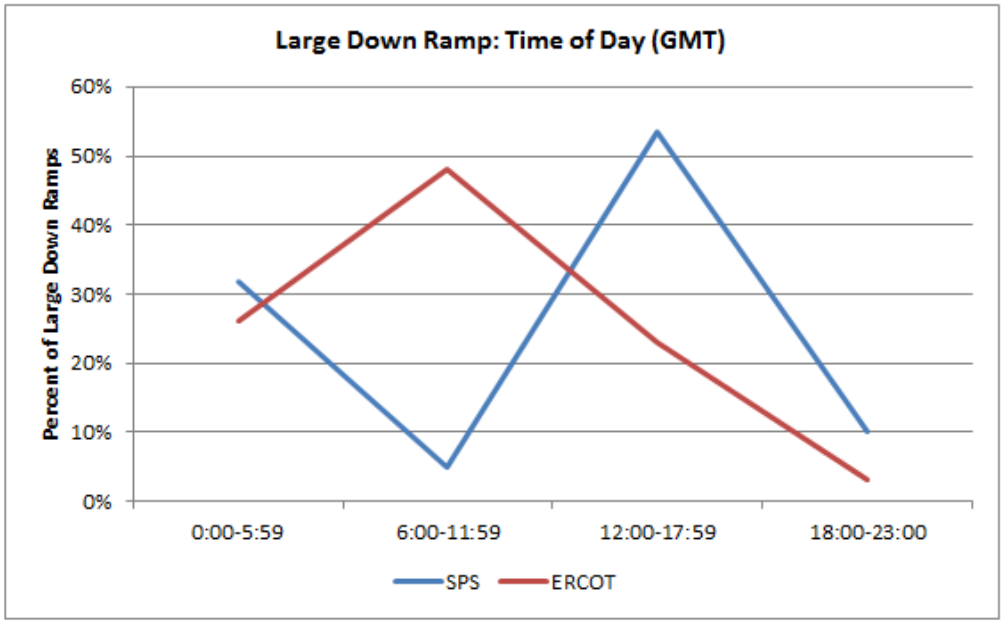
Maximum Duration Monotonic Large Down Ramp			
MW (% Max Gen)	*Duration (Hrs)*	*% Capacity*	*Ramp Rate (% Max Gen MW/Hr)*
92%	11	92%	8%

Table 5.11 – Large Down Ramp Time of Day Statistics

Diurnal Monotonic Large Down Ramps							
Hourly Time (GMT)	*% Events*	*% MW*	*Avg No. of Events per Year*	*Avg MW (% Max Gen)*	*Avg Duration (Hrs)*	*Avg % Capacity*	*Avg Ramp Rate (% Max Gen MW/Hr)*
24:00-5:00	32%	33%	61	58%	3.62	58%	23%
5:00-11:00	5%	6%	9	62%	5.47	62%	13%
12:00-17:00	53%	52%	103	56%	2.19	56%	34%
18:00-23:00	10%	10%	19	29%	1.48	29%	13%

[30] Note hours are in GMT. CST is GMT – 6 hours.

Figure 5.4 – Large Down Ramps Time of Day Comparison: SPP versus ERCOT



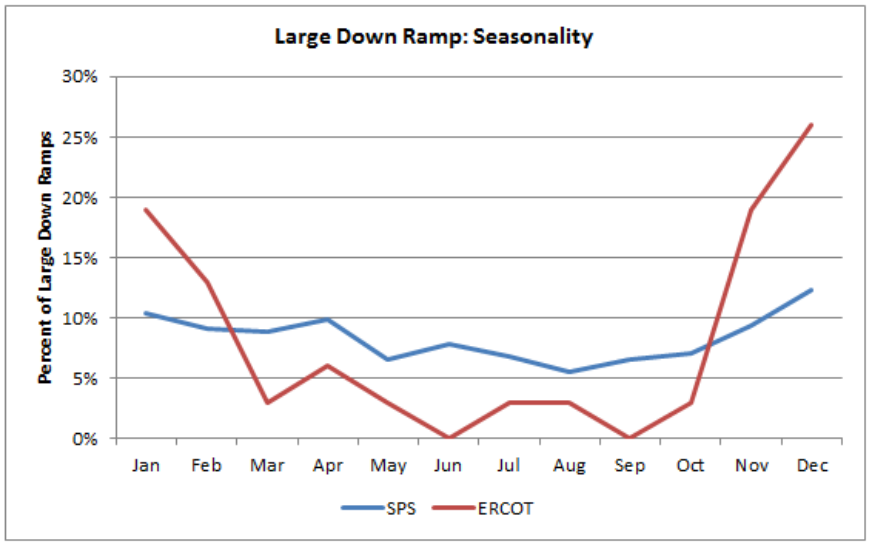
Finally, the number of large wind down-ramps remains fairly consistent over the seasonal weather cycles. Also, the average size of the ramps remains fairly consistent between 50% and 60% of maximum hourly generation; see Table 5.12 for seasonal ramping statistics. This is beneficial from the point of view of a demand response service provider because it would allow the program to remain active year round and allow it to target commercial and industrial load sources with less concern for seasonality. Further, the seasonal persistence of large down-ramps increases the impact on the control area's ability to meet demand as a significant number of ramps continue to occur during the summer months. Unlike SPS, however, ERCOT displays much greater seasonal variation. ERCOT has the greatest number of large down-ramps during non-peak seasons: winter and spring; see Figure 5.5.

Table 5.12 – Large Down Ramp Seasonality Statistics

Seasonality		Monotonic Large Down Ramps						
Season	*Season Desc*	*% Events*	*% MW*	*Avg No. of Events per Year*	*Avg MW (% Max Gen)*	*Avg Duration (Hrs)*	*Avg % Capacity*	*Avg Ramp Rate (% Max Gen MW/Hr)*
Spring	Mar-May	25%	25%	49	57%	2.32	57%	35%
Summer	Jun-Aug	20%	18%	39	50%	1.85	50%	37%
Autumn	Sep-Nov	23%	24%	44	58%	2.56	58%	31%
Winter	Dec-Feb	32%	33%	61	59%	2.38	59%	34%

Seasonality		Maximum MW Large Monotonic Down Ramp				
Season	*Season Desc*	*% MW*	*MW (% Max Gen)*	*Duration (Hrs)*	*% Capacity*	*Ramp Rate (% Max Gen MW/Hr)*
Spring	Mar-May	1.10%	92%	7	92%	13%
Summer	Jun-Aug	1.49%	87%	7	87%	12%
Autumn	Sep-Nov	1.19%	92%	3	92%	31%
Winter	Dec-Feb	0.85%	93%	8	93%	12%

Figure 5.5 – Large Down Ramps Seasonality Comparison: SPP versus ERCOT



The duration of large down-ramps coupled with the seasonal persistence large down-ramps and their occurrences during times of high load, make SPS a seemingly advantageous market for demand response to participate as a wind balancing resource. This is particularly true when compared to ERCOT, which already has very high levels of wind penetration and is a very active market for demand response service providers.

5.4.3 SPS Dispatachable Generation Data

There are thirteen significant thermal generators in the SPS territory. Although the territory has two large coal plants, the capacity factor of the coal plants are relatively low compared to other regions, indicating that base load may fluctuate more significantly, leaving more ramping capacity available. Because of the lower capacity factor of the coal plants in SPS the plants are taken to be load-following resources when available. This becomes significant when marginal cost of large wind down-ramps is evaluated. SPS does not have nuclear power plants or significant hydroelectric capacity, therefore concerns regarding significant exclusions from the hourly load data provided by the EPA is low[31]; see Table 5.7 for plant statistics.

Table 5.13 – SPS Dispatchable Thermal Generators

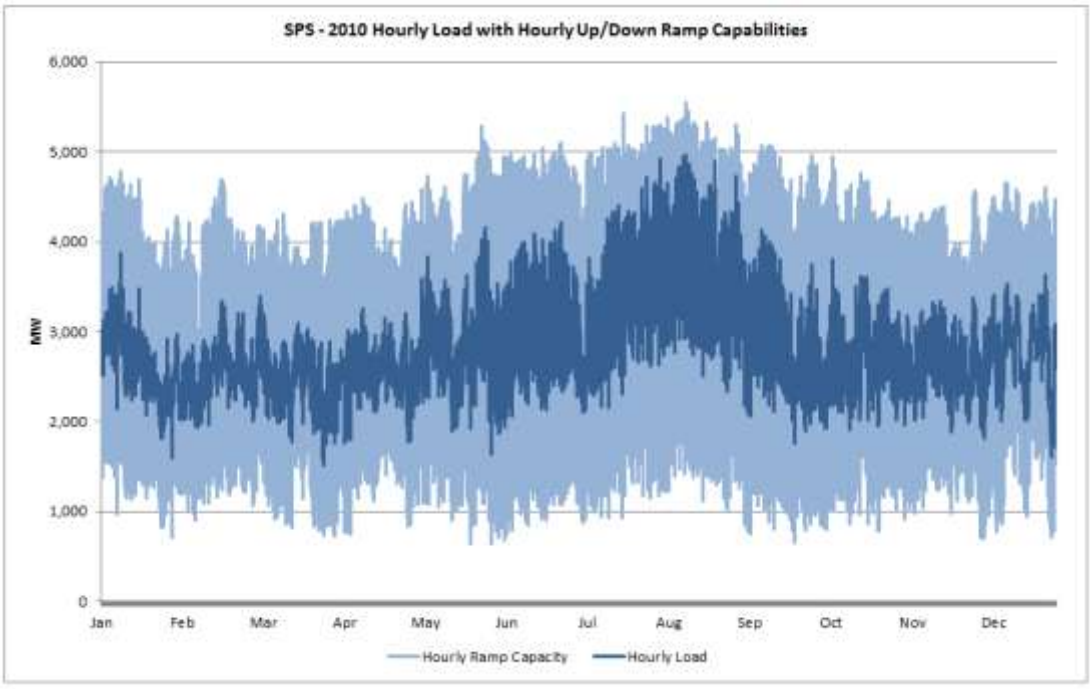
State	Plant Name	Control Area	Fuel Type	Capacity Factor	Name Plate Capacity (MW)	Heat Rate (mmBtu/MWh)	NOx Emission Rate (Tons/MWh)	CO2 Emission Rate (Tons/MWh)
TX	Black Hawk Station	SPS	NatGas	68%	254	7.63	0.000129	0.454
TX	Mustang Station	SPS	NatGas	52%	521	7.91	0.000156	0.470
TX	J Robert Massengale	SPS	NatGas	23%	107	8.01	0.000184	0.476
TX	Tolk	SPS	Coal	72%	1136	10.39	0.001147	1.066
TX	Jones	SPS	NatGas	42%	496	10.84	0.000545	0.644
NM	Maddox	SPS	NatGas	28%	213	10.90	0.000915	0.646
TX	Harrington	SPS	Coal	77%	1080	11.02	0.001360	1.131
TX	Nichols	SPS	NatGas	31%	476	11.14	0.000588	0.662
TX	Plant X	SPS	NatGas	35%	434	11.47	0.000779	0.682
NM	Cunningham	SPS	NatGas	31%	519	11.55	0.000919	0.686
TX	Mustang Station Unit 4	SPS	NatGas	5%	340	11.72	0.000210	0.696
TX	Ty Cooke	SPS	NatGas	10%	151	12.17	0.000972	0.722
TX	Moore County	SPS	NatGas	10%	49	25.91	0.002785	1.540

5.6.4 SPS Dispatching Generation Ramping Capacity

While the summer months had the least up-ramping capability, driven by load requirements, overall, the control area displayed very high hourly ramping capacity throughout the year. The minimum hourly ramp up capacity during the year was a sizable 330 megawatts and maximum of 1,970 megawatts; for the year SPS had an average hourly ramp up capacity of over 1,300 megawatts. Figure 5.4 illustrates that the market consistently holds large capacity for ramping power both up and down. This indicates a market with already significant load-following resources.

[31] See section 4.6.1 Dispatchable Generation Data Source Selection - Limitations

Figure 5.6 – SPS 2010 Hourly Ramping Capability



As described previously, there are three approaches taken to assess a market's ramping capabilities under various wind integration scenarios[32].

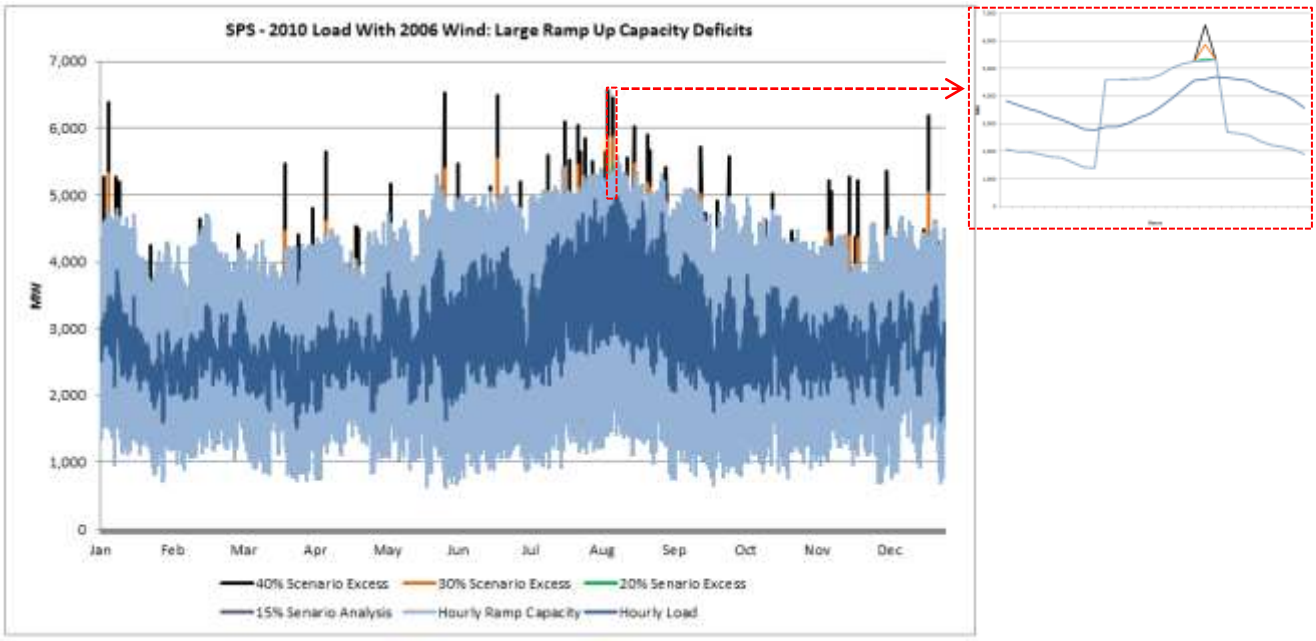
The first approach is to overlay the time series of the large wind down-ramps, identified under the wind ramp study, to the thermal generation ramp capability. The down-ramps identified to exceed a market's ramping capability were explicitly identified for each wind scenario. Under this approach, the number of wind-down ramps that exceed the ramp up capacity of the market is small. For example, the 40% wind scenario only has sixty-four such events. Though relatively few throughout all scenarios the volatility in ramp capability deficits grows substantially as wind penetration increases; under the 30% scenario, there is a total of almost a ten gigawatt hour deficit over the year increasing to forty-three gigawatt hours under the 40% scenario; see table 5.7. Figure 5.5 illustrates the magnitude of ramping capability deficits.

[32] See section 4.6.2 Ramping Capability Assessment

Table 5.14 - Insufficient Ramping Capacity for Scenarios

Wind Integration Scenario	Number of Events	Total Ramping Deficit (MWh)	Average Hourly Ramping Deficit (MW)	Min Hourly Ramping Deficit (MW)	Max Hourly Ramping Deficit (MW)
15% Wind	2	65	32	28	36
20% Wind	4	266	66	40	94
30% Wind	36	9,978	277	7	850
40% Wind	65	43,098	718	4	1,993

Figure 5.7 – Insufficient Ramping Capacity for Scenarios

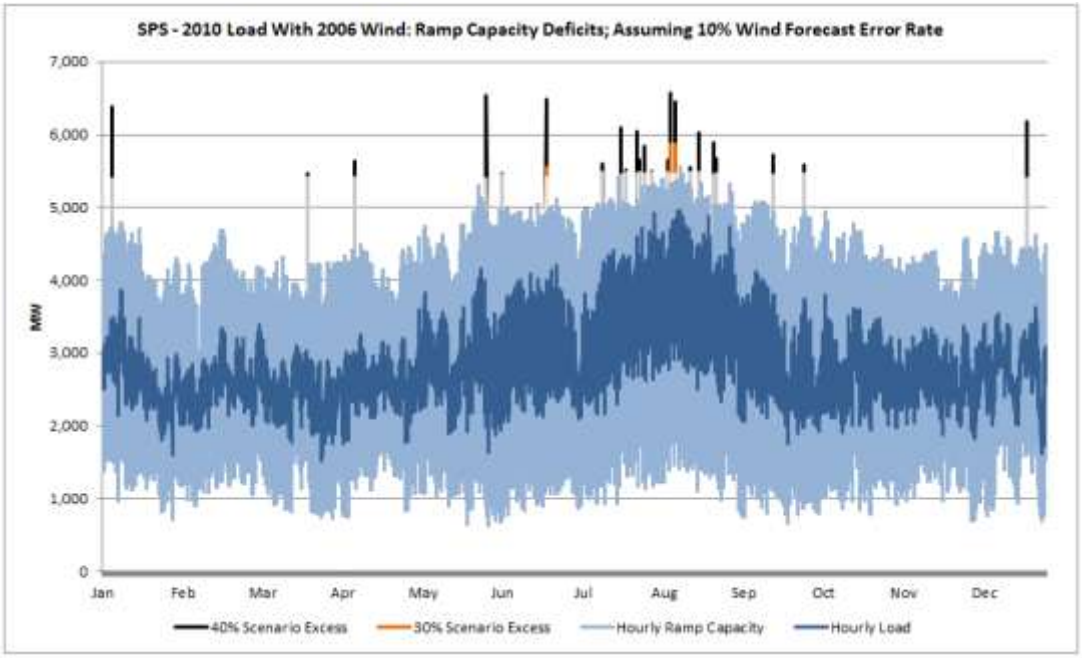


The second approach assumes a rational wind forecast error. The impact of the forecast error can be assumed to have symmetrical probability of forecasting over and under the actual wind load. SPS is assumed to have a ten percent forecast error, therefore this equates to a five percent error rate of underestimating wind down-ramps. Including forecast value significantly reduces the ramping deficit of SPS compared to the prior example; see Table 5.8 and Figure 5.6.

Table 5.15 - Insufficient Ramping Capacity for Scenarios; Assuming Forecast Value with Error of 10%

Wind Integration Scenario	Number of Events	Total Ramping Deficit (MWh)	Average Ramping Deficit (MW)	Min Hourly Ramping Deficit (MW)	Max Hourly Ramping Deficit (MW)
15% Wind	0	0	0	0	0
20% Wind	0	0	0	0	0
30% Wind	3	824	275	77	377
40% Wind	23	73,410	155	5	1,155

Figure 5.8 - Insufficient Ramping Capacity for Scenarios; Assuming Forecast Value with Error of 10%



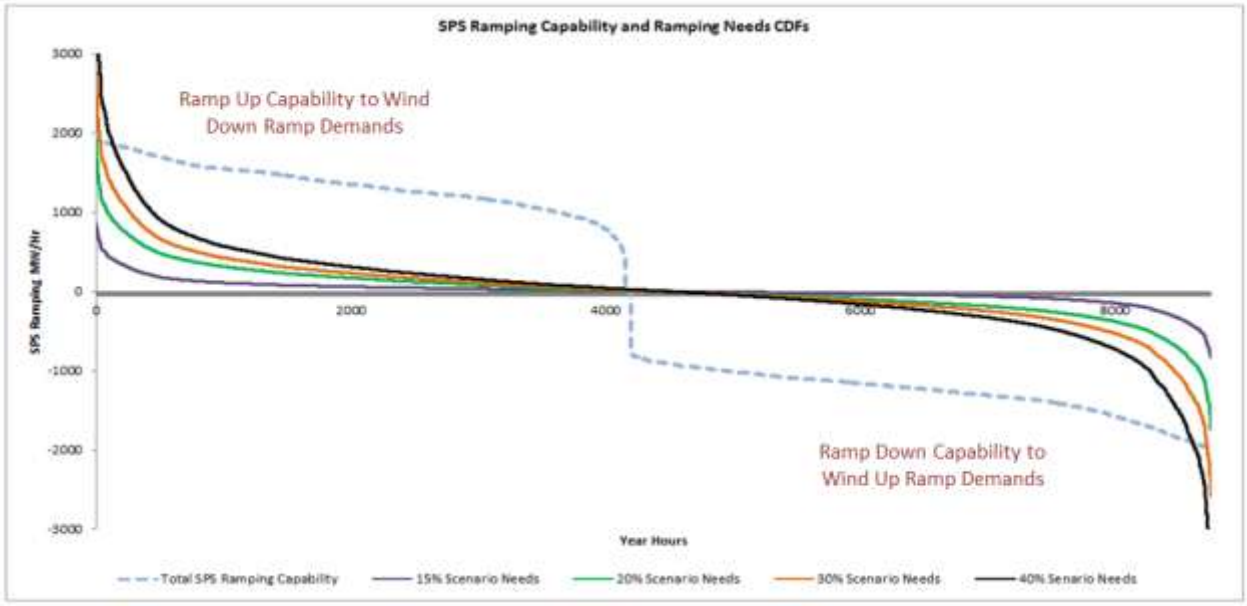
The third approach is to evaluate the cumulative probability function (CDF) of a markets ramping capability against the CDF of hourly wind step changes over the hours of a year under each wind integration scenario. In this approach all step changes in wind are evaluated. Further, this approach assumes that the largest step change in wind is matched with the greatest instance of ramp capability in the market. All temporal dependence between load demand and generation is removed. This approach can be seen as a compromise between the two prior approaches. Under this third approach there are many more ramping deficit events when compared to the first, however, no deficits occur under the 15% and 20% scenarios. As there are more events the total annual megawatt hours needed to cover wind down-ramps for the extreme integration scenarios is quite larger: seventy-three gigawatt hours under 40% scenario; see table 5.9 for statistical results. Although the ramp up capability of a market is of primary concern, due to the available option to

curtail wind, Figure 5.7 illustrates not only probabilistic ramp-up coverage of wind down-ramps, but also a market's ramp down capability to cover wind up-ramps. Note that the 20% scenario is very close to breaching the markets ramping capabilities.

Table 5.16 - Insufficient Ramping Capacity for Scenarios CDF Evaluation

Wind Integration Scenario	Number of Events	Total Ramping Up Deficit (MWh)	Average Ramping Up Deficit (MW)	Min Hourly Ramping Up Deficit (MW)	Max Hourly Ramping Up Deficit (MW)
15% Wind	0	0	0	0	0
20% Wind	0	0	0	0	0
30% Wind	338	12,239	36	12	784
40% Wind	473	73,410	155	3	1,927

Figure 5.9 - Insufficient Ramping Capacity for Scenarios CDF Evaluation



In summary, the analysis appears indicates that SPS does not offer great need for additional load-following resources in the near-term or in the long-term. It is not until the SPS has a 30% or 40% wind penetration level that material issues appear. Further, under the first two approaches the issues that appear are large, but infrequent, indicating a need for emergency demand side management programs rather than continual balancing services. The CDF approach, which is perhaps the most balanced approach of those evaluated, does indicate significantly more events than time series evaluations. Overall the SPS market appears to hold uniquely large hourly ramping up capabilities, which limits an additive resource tact to market entry.

6.0 Conclusion

After assessing wind markets in the United States using both qualitative and quantitative assessments of markets across the United States, we believe that demand response may be a viable and effective solution to wind down-ramps. Our analysis shows that wind generation will likely be integrated into areas that do not necessarily have capacity to manage a high influx of intermittent generation and therefore will need to consider developing additional generation sources or at least utilizing their ancillary services capacity with greater frequency.

Using publicly available data, we developed a unique tool that will help ISOs, RTOs, utilities or third-party demand response providers assess market conditions, characterize markets and loads, and quantify a market's potential. Specifically, our tool identifies a) markets across the U.S. that would best fit a model where demand response is integrated into ancillary services, b) characteristics of wind ramps (specifically, the magnitude, duration, rate, and frequency of down ramps) in a given region for chosen wind penetration levels, and c) electricity consumers present in the balancing authority of interest that may be ideal candidates to provide wind-balancing capacity to the grid by curtailing or completely shedding load.

In order to demonstrate our tool, we used it to assess a specific market - the Southwest Power Service (SPS) balancing authority - and build a case study. Our analysis of the region predicts that SPS will likely have a large amount of wind entering its system, however, it also appears that the system has enough ramping capacity to manage wind integration scenario up to twenty percent. We were able to quantitatively characterize the wind ramps in SPS and confirm load potential in the area. Although our initial study showed that SPS meets our criteria for using demand response to manage wind down ramps, the current market structure limits the participation of demand response (and specifically the bidding of demand response-based capacity by third-party providers) in this balancing authority. We assert that it is likely that these market barriers will be removed as the region is currently undergoing a process to modernize the organization of its power market. Demand response providers looking to pursue opportunities in ancillary services should continue to monitor the developments in SPS and the overall SPP RTO. Our findings demonstrate that with the appropriate market rules in place, high wind growth in the region will lead to substantial demand for increased ancillary services that can be met through responsive demand resources.

6.1 Areas for further research / Discussion

Although we were able to identify and assess a market's potential to integrate demand response into an ancillary services market, we believe that our tool can still be further enhanced. We based our assessment solely on publicly available data but believe that more comprehensive data, which is not likely available for public use, would improve our analysis and increase the utility and effectiveness of our tool. More specific data on loads present in the SPS region in addition to specific data on the electricity consumption of these loads would allow for a more accurate characterization of the specific load potential in the balancing authority. In addition, interviewing managers at specific establishments would further confirm opportunity costs and other potential barriers of identified loads providing demand response as ancillary services. Finally, performing an assessment of the cost of dispatchable ramping for wind balancing would be helpful to evaluate further market size potential for demand response in greater detail, particularly for markets that seem to exhibit enough ramp up capacity, such as what is exhibited in SPS.

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