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National Renewable Energy Laboratory

Innovation for Our Energy Future

Wind Energy Curtailment Case Studies

May 2008 — May 2009

S. Fink, C. Mudd, K. Porter, and B. Morgenstern
Exeter Associates, Inc.
Columbia, Maryland

Subcontract Report
NREL/SR-550-46716
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I. Introduction

Wind energy development has increased dramatically over the last decade. Over 8,500 megawatts (MW) of wind came online in the United States in 2008, bringing total U.S. installed wind capacity to about 25,000 MW.[1] This represents nearly a tripling in wind capacity just since 2006. According to the North American Electric Reliability Corporation (NERC), another 145 GW of variable resources (mostly wind) are in various stages of planning.[2] While not all of this capacity will come online, the amount of variable resource capacity that is under consideration in the United States is quite significant.

Investment in the nation's electric grid has failed to keep pace with the sharp rise in installed wind capacity in the United States. Transmission construction over the last 10-15 years has also fallen short of growth in electric demand. Though development of new transmission now appears to be increasing, lack of transmission is currently a primary barrier towards the expansion of wind capacity, in no small part because high-quality wind resources are typically located in areas far from load centers. In addition, wind development can generally proceed much more quickly than new transmission projects, leading to a timing mismatch between wind development and new transmission. Due to these factors, wind curtailment initiatives appear to be on the rise.

This paper presents a series of case studies on how wind curtailment is being used by different entities. To date, it appears that wind curtailment occurs for two primary reasons: 1) lack of available transmission during a particular time to incorporate some or all of the wind generation; or 2) high wind generation at times of minimum or low load, and excess generation cannot be exported to other balancing areas due to transmission constraints. In these instances, wind generation may be curtailed after other generation is running at minimum and imports reduced or curtailed as well.[3]

Wind curtailment initiatives are at an early stage of discussion or implementation, and what wind curtailment is in place differs across the country and is reflective of the regional electricity market that is in place. One can roughly categorize wind curtailment into the following categories:

- *Curtailment as Condition of Generator Interconnection* − Whereby wind generators are required to agree to curtailments if transmission constraints or system conditions require it. E.On Netz in Germany, for instance, requires wind generators to accept "wind power management" for interconnecting in Schleswig-Holstein and Lower Saxony until transmission upgrades are completed.

[1] American Wind Energy Association, "Wind Energy Grows by Record 8,300 MW in 2008," January 27, 2009, http://www.awea.org/newsroom/releases/wind_energy_growth2008_27Jan09.html.
[2] North American Electric Reliability Corporation, *Accommodating High Levels of Variable Generation,* April 2009, http://www.nerc.com/files/IVGTF_Report_041609.pdf.
[3] Not discussed in this paper are wind curtailments due to environmental reasons, such as for reducing or preventing bird and bat mortality. Wind projects in Altamont Pass in California are subject to periodic curtailments to minimize avian mortality. Recently, testing at Iberdrola's Casselman wind project in Pennsylvania found that turning off wind generation during low-wind-speed times during bat migration times reduced bat mortalities by over 70%.

- *Contractual* − Some utilities have included wind curtailments in power purchase agreements with wind companies, whereby utilities can curtail a certain amount of wind generation either at no cost or reduced cost. Other utilities may curtail wind and pay the wind generator for the lost value of wind power, and, in some cases, the lost value of the federal production tax credit.

- *Bid-based Curtailment* − More recently, the New York Independent System Operator (ISO) and PJM are allowing wind generators to bid a price that includes their willingness to curtail operations. Because of the value of the federal production tax credit and renewable energy credits, the wind bids may be zero or even negative.

- *Daily Operating Limits* − Until recently, the Electric Reliability Council of Texas (ERCOT) imposed daily operating limits on wind projects in West Texas by calculating the amount of generation that could be reliably operated within the area based on the projected daily dispatch of generating units (including wind) in the McCamey region. With the planned addition of new transmission and the implementation of a nodal market in late 2010, ERCOT removed the daily operating limits for wind in West Texas and made all wind in Texas subject to ERCOT's transmission congestion protocols.

- *Differences by Type of Wind Technology* — ERCOT also distinguished between wind plants in West Texas as either rapid response wind farms (RRWF), which are wind resources that can respond within 15 minutes of getting a request, or slow response wind farms (SRWF), which must respond within 30 minutes of getting a request. RRWFs tended to be newer wind farms with more advanced control capabilities. The RRWFs were allowed to operate above their daily limit (SRWFs were not), but had to reduce generation upon request if reliability issues arose. If RRWFs were asked to reduce generation to deal with the congestion in the following hour, SRWFs were required to reduce generation by more than their pro-rata share to allow the RRWFs to recoup some of the lost generation and the associated revenues.

- *Reserves* − Bonneville Power Administration (BPA) will consider curtailing wind power in an over-generation situation if 90% of BPA's balancing reserves have been utilized. BPA assigns a maximum generation limit for variable generators if BPA is in an over-generation situation. Once 90% of BPA's reserves have been utilized, variable generators that have substantially over-generated relative to their schedule will be required to reduce generation to a specified level. Variable generators that have substantially under-generated relative to their schedule will be curtailed down to actual levels.

Table 1 provides more detail on various wind curtailment initiatives in the United States. It should be noted that grid operators, either through interconnection agreements or operating rules, may curtail any generation (including wind) to maintain reliability, such as during emergency situations, transmission constraints, or minimum load situations. In addition, generator curtailment may be an agreed-upon condition for certain transmission arrangements. Under transmission service agreements in non-regional transmission operator (RTO) markets, for example, non-firm transmission service provides transmission service when the transmission grid is not constrained, and the transmission service is reduced or cut when the transmission grid is constrained. Conditional-firm transmission service is another example, where transmission service is firm except during certain times or can be curtailed by the grid operator for a certain number of hours annually.

Table 1.

Examples of Wind Energy Curtailment Practices in the United States

	Description	Constrained Operation Procedures	Amount Curtailed	Compensation
ERCOT	Congestion is currently managed by ERCOT on a zonal basis. The majority of wind is near McCamey, in the western zone. ERCOT used special rules for this zone as transmission constraints limited transfers from the zone into the load centers in eastern Texas. ERCOT imposed daily operating limits for wind plants in the McCamey area based on projected generation and demand. This protocol was removed effective Sep. 1, 2009, in preparation for the transition to nodal markets.	ERCOT may call upon wind plants in to make reductions in output during periods of transmission congestion. New nodal market rules being implemented.	January to August 2008, curtailed approximately 140-150 MW about 45-50% of the days, via restricted daily operating limits. From December 2008 to July 2009, curtailed between 500 MW and 1000 MW daily, and at times curtailing up to 3000 MW daily.	If McCamey area plants were called upon for curtailment, ERCOT paid out-of-merit energy payments, but only up to the daily operating limit. New nodal market rules being implemented.
Midwest ISO	No specific wind curtailment program. Will curtail wind during Minimum Generation Events along with other generation resources according to economic order.	During Minimum Generation Events, will order curtailments in the following order: 1. Generation identified through the Reliability Assessment Commitment process. 2. Generation above the day-ahead schedule from non-DNRs (Designated Network Resources). 3. Generation above the day-ahead schedule from DNRs. 4. Non-DNR committed in the Day Ahead Market. 5. DNRs and firm imports committed in the Day Ahead Market	No ISO-wide data available.	Locational marginal price (LMP) -based market, no additional compensation.
New York ISO	Wind integrated into real-time and day-ahead market dispatch. Wind bids price-quantity curve into real-time market and is dispatched economically along with other generation. Wind plants must participate in wind forecasting and be able to accept electronic basepoint dispatch signals.	During constrained operations generation will be curtailed according to economic bids. Wind plants must follow electronic basepoint dispatch signals within 5 minutes or be assessed penalties for non-compliance.	No data available.	LMP-based market, no additional compensation.
PJM	Wind included in procedures for Emergency Events and Light Load Events. Wind curtailed along with other generation based on economic and emergency minimums. Wind assumed to have minimum of zero unless otherwise bid. Wind plants are required to participate in forecasting system and be able to accept electronic basepoint signals.	During events, all generation reduced to economic minimums first. If additional curtailment needed, all generation reduced to emergency minimum levels. Wind plants are required to respond to electronic basepoint dispatch signals within 15 minutes or must notify PJM if they cannot respond that quickly.	No data available.	LMP-based market, no additional compensation.

	Description	Constrained Operation Procedures	Amount Curtailed	Compensation
Bonneville Power Administration	Curtailment procedures included in wind Large Generation Interconnection Agreement for system events. Wind plants required to participate in forecasting and be able to accept electronic basepoint signals.	When 90% of balancing reserves deployed, BPA can assign generation limits to wind plants based on scheduled output plus a pro rata allocation of balancing reserves. Wind plants must respond to electronic basepoint signals within 10 minutes or BPA can disconnect the plant.	No data available.	No compensation.
Hawaiian Electric Company	All wind plants are equipped with grid operator controlled curtailment interfaces. Grid operator sets electronic basepoint generation limits as necessary.	During system emergency events grid operator will use most effective control to address issue (such as reducing a specific wind plant output). During light load times, Must-Run Generators reduced to minimum levels, then As-Available Generators (including wind) curtailed according to a pre-determined priority established via contractual agreements.	No data available.	No additional compensation, curtailments built into contractual agreements.
Xcel Energy	Northern States Power MN (NSP) is in Midwest ISO and follows the Midwest ISO's direction on whether curtailment is required. Public Service of Colorado (PSCO) and Southwestern Public Service (SPS) have procedures to reduce all generation and prices/sales to minimum levels prior to ordering wind energy curtailments.	NSP: agreements with wind plants in Southwest Minnesota to curtail on a rotational basis when required by Midwest ISO. PSCO: contracts with wind plants to curtail a set amount per year on an as-needed basis. If additional curtailment required PSCO will call wind plants to reduce generation according to a schedule based on the day of the month.	NSP: about 23,000 MWh in 2008. PSCO: about 3,000 MWh in 2008.	NSP: make whole kWh payments for both fixed and variable costs. PSCO: contracted amounts are at no cost. Additional amounts made whole for energy plus Production Tax Credit.
Southern California Edison	Wind curtailment system in place for the Tehachapi region due to transmission constraints.	Agreement with Terra-Gen Power to reduce output on an as-needed basis.	About 15 MW for 3-4 hours about every two days (or 6-8% of the time).	Make whole payment for energy.

Data on how much wind is being curtailed is difficult to obtain and inconsistent in format from grid operator to grid operator. ERCOT curtailed about 140-150 MW of wind for 45-50% of the days between January through August 2008. From December 2008 through July 2009, ERCOT curtailed between 500 and 1000 MW daily, and between 2500 MW and 3000 MW on some days between February and April 2009. BPA reported curtailing wind generation in July 2008, although how much was curtailed is not known. Because of transmission issues, Xcel Energy curtailed 23,000 MWh of wind generation in the Midwest in 2008, at the direction of the Midwest ISO. From 2005 to 2007, nearly 5% of Xcel's Minnesota wind generation was curtailed each year. Xcel Energy also made wind curtailment payments in Minnesota ranging from below $1 million in 2006 to nearly $6 million in 2007, then falling to $2.5 million in 2008. In Colorado, Xcel Energy curtailed about 3,000 MWh of wind generation in 2008. In Alberta, wind energy projects were curtailed for 860 hours in 2008. Southern California Edison estimates it curtails about 15 MW of wind generation for three to four hours every two days, or about 6-8% of the time, in the Tehachapi region, although the development of the $2 billion Tehachapi transmission project should ease (if not eliminate) the need for wind curtailment in that region. Wind curtailment has also occurred in Germany and Spain, although data on how much wind curtailment took place is also sparse. In 2007, 23.9 GWh of wind generation in Spain was curtailed, representing 0.09% of total wind production.

A key issue that will determine whether significant levels of wind power can be added is the availability of new transmission. High-quality wind resources tend to be in remote areas where the capacity of the transmission grid is inadequate relative to the available wind resource. Furthermore, there is a timing mismatch between the development of wind projects and the development of transmission projects, with transmission projects taking much longer than wind projects on average. Several transmission projects have been announced or are in planning that may accommodate thousands of megawatts of new wind projects by the time these transmission projects are in operation between 2013 and 2015. The timely completion of these transmission projects is by no means certain though, and wind curtailment will likely persist, if not worsen, until new transmission is available. Larger balancing areas, dynamic scheduling, and dynamic ratings of transmission lines may also reduce wind curtailment.

This paper consists of a series of case studies that summarizes wind curtailment proposals and initiatives in the United States and abroad. To the extent possible, data on how much wind is curtailed is provided, although this data is not always easy to collect. The paper closes with a summary.

II. Wind Power Curtailment Examples in the United States

Electric Reliability Council of Texas[4]

Texas has the most installed wind capacity of any state in the United States, with about 8,000 MW in operation as of April 2009. Most of this wind capacity is in west Texas. Due to transmission constraints, ERCOT can accommodate only about 4,500 MW of wind, assuming there are no transmission outages.[5] During periods of high wind production, generation can exceed the reliability limits on a given transmission line. ERCOT manages congestion on a zonal basis, and the generators that have the greatest effect on the constraint are typically curtailed first.

Under its zonal system, ERCOT calculates a real-time market clearing price for energy (MCPE) every 15 minutes based on projected load and generator offers. ERCOT procures and schedules the amount of balancing energy needed for every 15-minute interval (paid the interval MCPE) through the market on a merit basis, awarding the opportunity to provide regulation energy to the lowest cost resources first. Because balancing energy is procured from the least-cost offers, the generators are not always optimally located and can lead to overloading of transmission lines in certain areas. To compensate for this, ERCOT also procures what is termed out-of-merit energy (OOME) from the units needed to alleviate congestion in a particular zone. Unit curtailments consist of OOME-Down instructions. In any given 15-minute interval, OOME-Down is paid the interval MCPE, i.e., the generator is compensated for lost production up to its scheduled output level.

Conventional generators are required to operate within ±1.5% of their scheduled amount. To accommodate wind energy variability, ERCOT granted wind generators the right to deviate from scheduled amounts by ±50%. This system created a perverse incentive for suppliers scheduling wind energy, leading them to over-schedule generation, which often resulted in them receiving additional OOME-Down payments.[6] This was especially an issue in west Texas where transmission capacity is lacking to transport the energy from wind projects. From 2003 through August 2009, ERCOT assigned generation limits to wind projects in west Texas on a daily basis and OOME-Down payments were only made up to the daily limit. The way wind curtailment will be dealt with will change as ERCOT transitions to a nodal market system in late 2010. The nodal market will use locational marginal prices (LMPs) that factor in nodal congestion, and balancing energy procurement will become a market-based function (discussed in greater detail below).

Wind resources are particularly concentrated in the McCamey area in west Texas and thus, curtailment in this region is prevalent and until recently, was governed by special rules. ERCOT designated wind plants in McCamey as either RRWFs, wind resources that can respond

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[4] ERCOT declined to review this section. The information presented here is based on the authors' understanding of wind curtailment in ERCOT.

[5] Personal communications with ERCOT personnel, February 3, 2009.

[6] R. Sioshansi and D. Hurlbut, "Market Protocols in ERCOT and Their Effect on Wind Generation," submitted to Energy Policy, http://iwse.osu.edu/isefaculty/sioshansi/papers/ERCOT_wind_mkt_design.pdf.

within 15 minutes of getting a request, and SRWFs, which must respond within 30 minutes of getting a request. RRWFs tend to be newer wind farms with more advanced control capabilities (see Table 2). ERCOT currently procures balancing energy as spinning reserves and as non-spinning 30-minute reserves (on an as-needed basis). The variability of wind energy may require response times shorter than 30 minutes, but of a long enough interval (10 to 15 minutes generally) that using spinning reserves is impractical and expensive. The RRWF plants can act in the shorter 10 to 15-minute interval, thereby reducing ERCOT's need to maintain additional spinning reserves. Under the old protocol, ERCOT calculated a quantity of tradable generation rights (TGR), equivalent to the amount of generation that could be reliably operated within the McCamey area based on the projected daily dispatch of generating units in the region. The TGRs, posted by ERCOT in the day-ahead market, were in the amount of the operating limits assigned to the wind plants for the next operating day. Tradability of the generation rights was not implemented, and plants were simply held to their operating limits, but concepts such as tradable rights are being discussed with regard to ERCOT's proposed nodal market design. The daily operating limits protocol for the McCamey area was removed effective September 1st, 2009, in preparation for ERCOT's nodal market.

Table 2.

Example of Daily Operating Limits for Wind in ERCOT

Wind Unit Name	Capacity (MW)	On-Peak Limit (MW)	Off-Peak Limit (MW)
SW Mesa	75	67	65
Orion (RRWF)	83	82	78
Desert Sky 1	84	83	79
Desert Sky 2	77	76	73
Woodward Mount 1 (RRWF)	83	75	71
Woodward Mount 2 (RRWF)	77	69	66
King Mount NE	79	71	68
King Mount NW	79	71	68
King Mount SE	40	36	34
King Mount SW	79	71	68
Total	756 MW	701 MW	670 MW

Source: ERCOT, "Section 7.8 – Congestion Management in McCamey Area," presentation for WMS Conference Call, May 31, 2007.

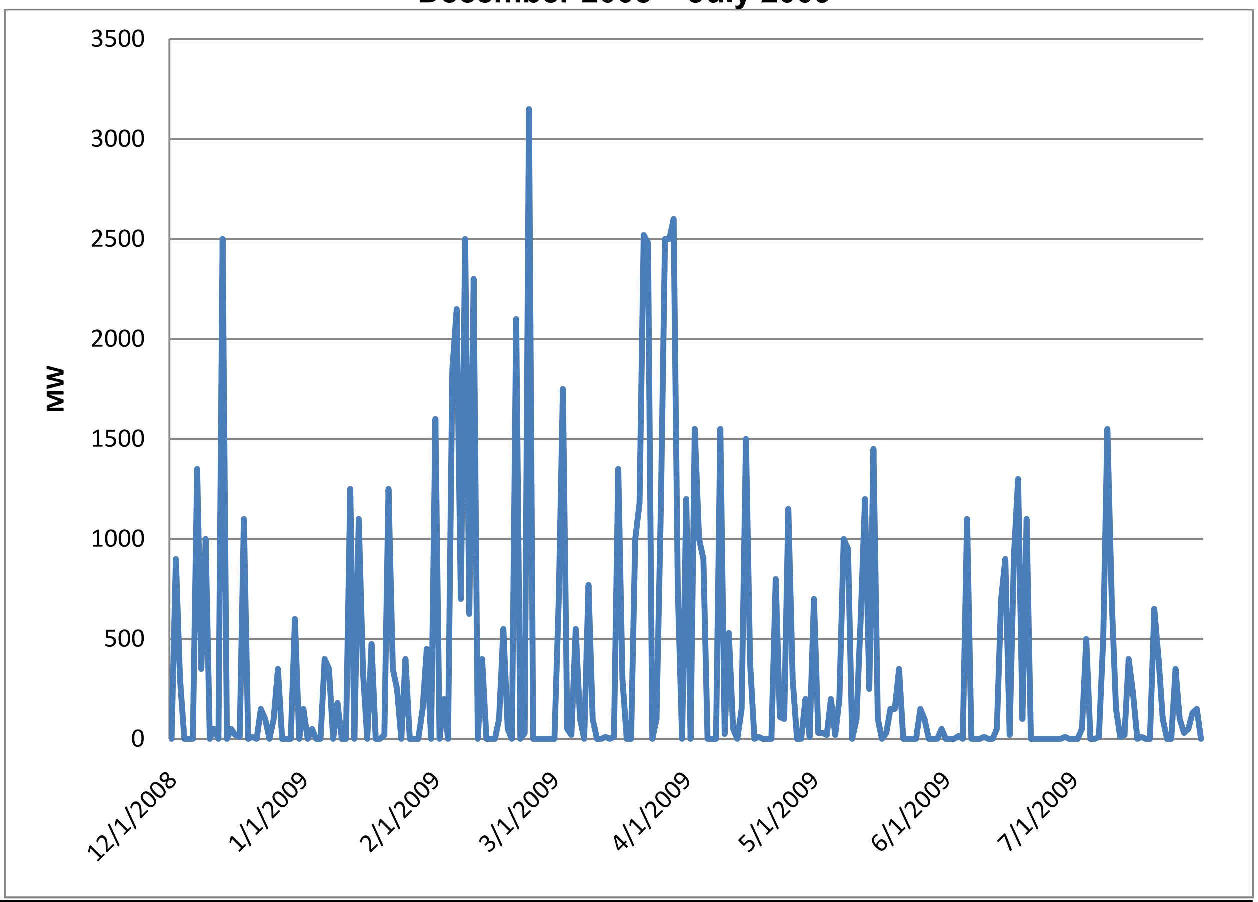
The RRWFs were allowed to operate above their daily limit (SRWFs are not), but would have to reduce generation upon request if reliability issues arose. During constrained periods, the transmission capacity was compared to the amount of TGRs in real time. If too many TGRs were present, meaning more generation was scheduled than could be accommodated by the grid, RRWFs were asked to reduce generation to deal with the congestion. In the following hour, SRWFs where then required to reduce generation by more than their pro-rata share to allow the RRWFs to recoup some of the lost generation and the associated revenues. On days that ERCOT was required to curtail wind from January through August 2008, the average amount curtailed was approximately 140-150 MW. ERCOT was required to curtail wind approximately 45-50% of the days during that time period.[7]

[7] Personal communications with ERCOT personnel, February 3, 2009.

Data from December 2008 through July 2009 showed that ERCOT is curtailing a significant amount of wind power on a daily basis. Figure 1 indicates that ERCOT typically curtails between 500 and 1,000 MW of wind capacity daily during the peak hour, with much larger increases to between 2,500 and 3,000 MW on some days from February 2009 through April 2009. The wind curtailment is done in real time and does not include balancing down instructions that ERCOT sends as a result of ERCOT's real-time balancing market. Furthermore, because only the peak hour is measured, not all wind curtailment throughout the day is represented.[8]

Figure 1.

Estimated Capacity of Wind Curtailed Daily during the Peak Hour in ERCOT December 2008 – July 2009



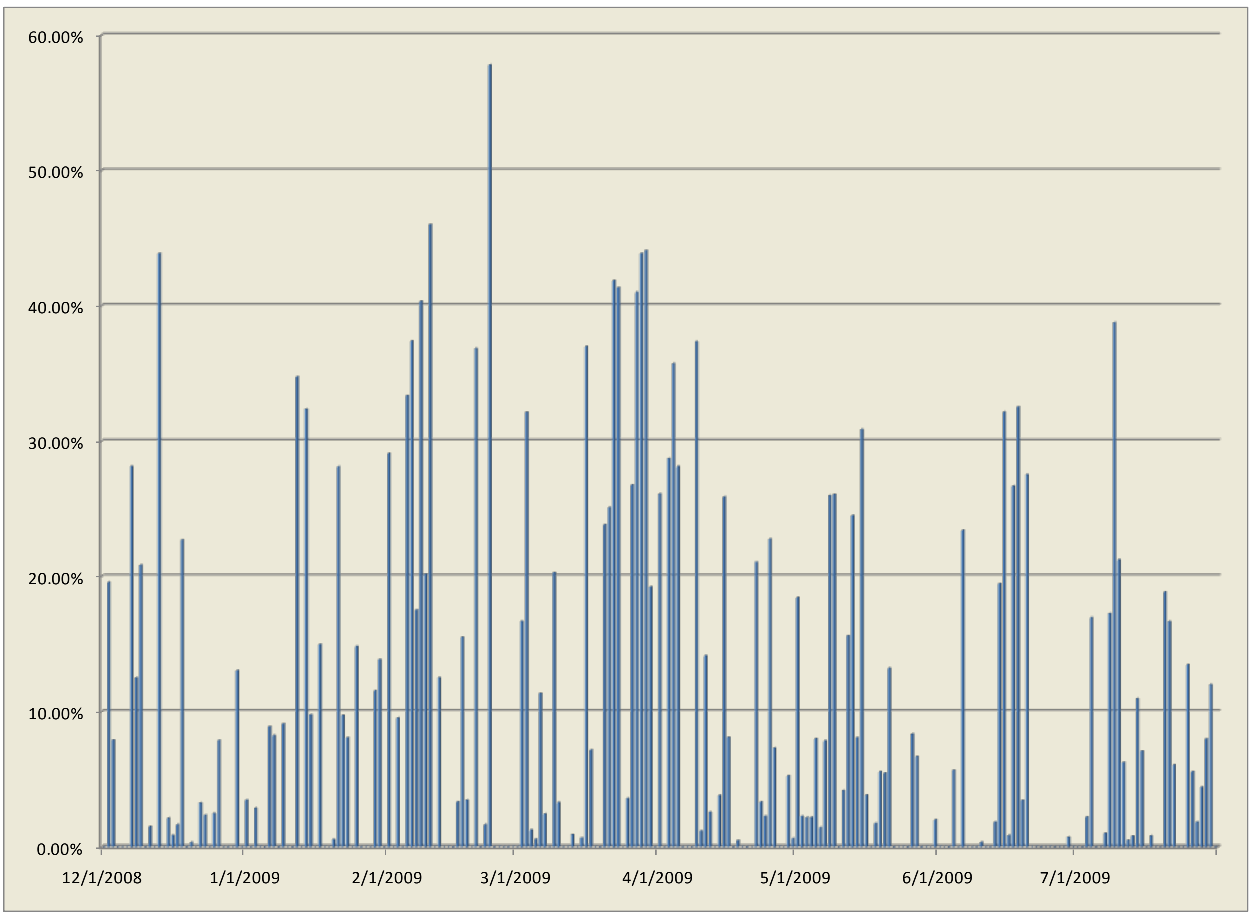
Source: Estimated from Monthly Staff Presentations to the ERCOT Board of Directors, December 2008 through July 2009.

[8] For the data in Figures 1 and 2, ERCOT mostly used average wind output and wind curtailment for the peak load hour of the day, but for May and July, ERCOT used actual wind output and both resource-specific and portfolio curtailments averaged over the entire day. ERCOT said this will be the method they will use going forward.

Encompassing the same December 2008 through July 2009 period, Figure 2 depicts the proportion of wind that was curtailed daily as compared to the total amount of daily wind output. Although the percentage of wind curtailed in ERCOT varies considerably from day to day, it exceeds 30% on over 20 occasions, over 40% on nine days, and over 50% on one day.

Figure 2.

Percentage of Wind Curtailed Daily during the Peak Hour in ERCOT as Compared to Daily Aggregate Wind Output December 2008 – July 2009



Source: Estimated from Monthly Staff Presentations to the ERCOT Board of Directors, December 2008 through July 2009.

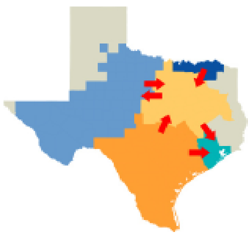
Transition to a Nodal Market

ERCOT is in the process of implementing a new market design by late 2010, designated the Texas Nodal Market, as directed by the Public Utility Commission of Texas (PUCT) in 2003 (see Figure 3). The Nodal Market will establish a day-ahead market for energy, ancillary service capacity, and certain congestion revenue rights, and will use LMPs at individual bus-bars.

Figure 3.

ERCOT Nodal versus Zonal Market System

Zonal Market



In today's zonal market, the grid is divided into Congestion Management Zones (CMZs), which are defined by the Commercially Significant Constraints (CSCs).

Several limitations have been identified with the current zonal model:

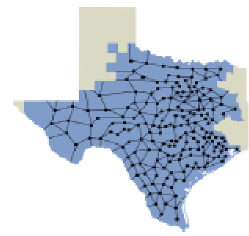
- **Insufficient price transparency** – This results in less efficient power dispatch, less efficient congestion management tools and muted or distorted signals for investment.
- **Resources grouped by portfolio** – QSEs submit schedules for a group of resources (portfolio) in a specific zone, and ERCOT operators have limited options to resolve congestion.
- **Indirect assignment of local congestion** – Participants who contribute to local congestion are not directly assigned the associated costs.

Nodal Market

Moving to a nodal design will satisfy the PUCT order to directly assign local congestion.

In the nodal market, the grid will consist of more than 4,000 nodes, replacing today's CMZs.

The Texas Nodal design is expected to deliver the following benefits:



- **Improved price signals** – More granular pricing will encourage additional generation and/or transmission investment in the proper locations.
- **Improved dispatch efficiencies** – Dispatching at the resource level will yield a lower overall cost of power supply.
- **Direct assignment of local congestion** – Settlement prices are based on locational marginal costs.

Source: ERCOT, *Understanding: Texas Nodal Market Implementation,* January 23, 2008, http://nodal.ercot.com/about/kd/understandingNodal012308.pdf.

In ERCOT, generators and load-serving entities (LSEs) do not always deal directly with ERCOT system operators. Generators and load-serving entities are represented by qualified scheduling entities (QSEs)[9] that handle (among other things) scheduling and financial settlements. Currently, ERCOT does not have a day-ahead market for energy. Energy is scheduled by QSEs for the next operating day through bilateral agreements. ERCOT runs a separate ancillary services market for capacity for the next operating day. Under the nodal market, these two functions will be centralized into the day-ahead market, where ERCOT will clear the market for day-ahead energy and ancillary service capacity simultaneously. The current balancing energy system where generators receive OOME payments will also be replaced. The new Reliability Unit Commitment (RUC) process will ensure sufficient capacity is available at each node and will be calculated on a day-ahead and an hourly basis for each node.

The new security-constrained economic dispatch (SCED) will settle the markets in real-time every 5 minutes using LMPs at each node. The SCED will dispatch individual resources (including wind) throughout the grid in economic merit order, managing congestion and maintaining security on a nodal basis. Under a nodal system and with additional transmission being constructed to access wind energy in west Texas, the special rules governing the McCamey area plants will no longer be required. ERCOT is in the process of changing its procedures and wind management protocols to integrate wind into the nodal market system, where wind will be bid into the markets and treated in the same way as other generation

[9] A generator or load-serving entity (LSE) can also be a QSE.

resources. A protocol revision request (PRR 810)[10] was submitted in April 2009 and approved in August 2009, to remove the congestion protocols for wind projects in McCamey, and allow wind projects in west Texas to be treated in the same fashion as other wind projects in terms of their impact on transmission congestion in ERCOT.

PJM Interconnection[11]

PJM encompasses all or parts of 13 states and the District of Columbia, and includes about 163 GW of generation. Wind makes up a small but growing generating resource in PJM, with about 2,200 MW of wind in operation and another 1,700 MW under construction.[12] Generation facilities can choose to be capacity or energy-only resources. Wind generation facilities that choose to be counted as capacity resources and participate in PJM's Reliability Pricing Model (PJM's three-year forward capacity market) have their capacity value calculated annually based on historical performance during the three previous summers.[13]

In late 2008, PJM formed the Intermittent Resources Working Group (IRWG) to examine market, operational, and reliability issues associated with intermittent resources. The IRWG is developing recommendations for fully integrating wind energy into the PJM market. In June 2009, PJM implemented changes to its dispatch software so that wind generators located in constrained areas receive an appropriate price signal to curtail generation. Additionally, PJM is initiating a wind forecasting program. In conjunction with the integration of wind power forecasting into PJM markets, IRWG will consider changes to how operating reserve charges are applied to intermittent resources. PJM selected a wind forecast vendor (Energy and Meteo Systems GmbH) and launched its wind forecasting system in April 2009. Ultimately, Energy and Meteo Systems GmbH will produce multiple forecasts, including hourly forecasts for the week ahead and short-term forecasts every five minutes for the operating day.

Wind curtailment may be applied for two different market circumstances − during constrained operations and during light load events. During constrained operations, PJM curtails generation based on a cost-effective re-dispatch calculation. When more generation is needed, wind generators will not be dispatched upward, as they are assumed to be operating at their maximum economic generation. By contrast, during emergency events when generation needs to be reduced, wind units may be dispatched down.

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[10] ERCOT, *PRR810 – Remove McCamey Congestion Management*, approved August 18, 2009, www.ercot.com/.../810PRR-01_Remove_McCamey_Congestion_Management_040109.doc. See also *ERCOT News: August Board Meeting Highlights; IMM Report*, August 19, 2009, www.texasenergyreport.com/energypress/downloadep.cfm?dcid=45.

[11] Much of the information in this section taken from PJM Intermittent Resources Working Group materials, accessed February 1, 2009, http://www.pjm.com/committees-and-groups/working-groups/irwg.aspx.

[12] Sanjay Patil, "Wind Forecasting Process Development," Presentation before the Utility Wind Integration Group Annual Meeting, Philadelphia, PA, April 2, 2009.

[13] A default 13% capacity value is the class average for wind facilities in PJM and is re-evaluated annually by PJM. For more information, see the following: PJM, Manual M-21, *Rules and Procedures for Determination of Generating Capability*, Revision 7, June 2008, available at: http://www.pjm.com/~/media/documents/manuals/m21.ashx.

During constrained operations, wind generation is subject to curtailment if it has an impact of greater than 5% for contingency overloads and 3% for actual overloads. PJM will curtail wind down toward its Economic Minimum on a cost-effectiveness basis. When determining what generation should be re-dispatched or curtailed to manage congestion, PJM subtracts the generating unit bid price from the dispatch price, then divides the result by the generation shift factor as calculated by PJM in real-time.[14] Curtailments will be based on the unit offer and lowest $/MW relief on constraint. Wind generation being lowered for a constraint may contribute to setting LMP. PJM wants wind plants to achieve the required curtailment within 15 minutes or within a timeframe that the wind farm technology permits. If the curtailment will take longer than 15 minutes, then PJM should be notified. Once economic re-dispatch is exhausted, PJM may request further curtailment of wind generation toward the Emergency Minimum limit if the constraint still exists. The Emergency Minimum for wind plants is set at zero. The Economic Minimum is also assumed to be zero unless some other value has been submitted by the wind generator based on blade feathering capability or other control limit. PJM allows all generators (including wind generators) to bid in negative prices; therefore, wind plants can submit bid curves with negative prices. This may be desired due to federal production tax credits and the sale of renewable energy credits.

PJM publishes market notices if a light load event is expected. Light loads generally occur during the spring and fall, and sometimes on summer weekends. The market notice will explain what percentage of generation is expected to be reduced by market participants after all economic curtailment is utilized. In real-time operations, a Minimum Generation Emergency Event is initiated after all units are at Economic Minimum and additional generation reduction is required. During a Minimum Generation Emergency Event, all Emergency Reducible Generation (ERG) is reduced by an equal percentage (i.e., 20%, 30%, etc.), where the available ERG is equal to the Economic Minimum minus Emergency Minimum. PJM does not differentiate between resource types during a Minimum Generation Emergency Event. However, after all ERG has been utilized, PJM will consider the impact of directing wind to shut down prior to de-committing steam generation. PJM dispatchers can recommend that specific generating units not required for current area protection or not required for the subsequent on-peak period be shut down first.[15] This is due to long turn-around times of baseload steam units that may be required for the next operating day's on-peak period.

New York Independent System Operator[16]

As of February 2009, the New York ISO's (NYISO) total wind power capacity was 1,274 MW and may reach 6,500 MW by 2011.[17] The wind development is located primarily in

[14] The generation shift factor predicts the effect of changes in generation on transmission line flow.
[15] PJM, "Manual 13: Emergency Operations, Section 2: Capacity Emergencies," Revision 36, Effective Date: June 30, 2009, http://www.pjm.com/documents/~/media/documents/manuals/m13.ashx.
[16] Information in this section from the New York ISO, *Integration of Wind into System Dispatch, A New York ISO White Paper,* October 2008, http://www.nyiso.com/public/webdocs/documents/white_papers/wind_management_whitepaper_11202008.pdf.
[17] NYISO press release, "NYISO Marks Wind Power Milestone," February 26, 2009, http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/NYISO_Marks_Wind_Power_Milestone_02262009.pdf.

the northern and western regions of New York and there is typically insufficient transmission capacity to transfer the large amounts of wind expected in the area to the load centers of southeastern New York. NYISO anticipates that dispatching other resources around the availability of wind plant output, which has been the standard procedure, will soon become an inadequate solution and longer-term solutions are needed. The long-term solutions identified in a NYISO white paper released in October 2008 are:

- Facilitate the building of additional transmission to the north and west.
- Promote energy storage development to absorb the excess off-peak power.
- Implement new operational rules.

NYISO is working on all three solutions and in early 2009 started implementing their new market rules for variable resources. In moving to a more market-based system for operation of wind power facilities, NYISO anticipates having more efficient dispatch orders during constrained periods. NYISO's new dispatch system went into operation in May 2009.

Under the new dispatch procedures, NYISO evaluates each generating resources' (including wind) economic preferences based on their submitted offers to determine the least-cost means of meeting load requirements while maintaining reliability. This transforms NYISO's wind plant control method from one of manual curtailment-upon-need to a market-based wind plant management system. NYISO integrated wind plants into its economic dispatch to ensure they will be treated like all other generators.

In the NYISO market, conventional generators indicate their willingness to re-dispatch through their economic offers. Under the new procedures, wind plants are required to submit economic price curves into the real-time market, which are due 75 minutes before each operating hour. These price curves, or bids, consist of price-quantity pairs that indicate the LMPs at which the wind plant would prefer to operate. Up to 11 price-quantity pairs can be submitted each time and they can vary each time. Recognizing that wind plants cannot offer to increase production, the offers from wind plants indicate the prices below which a wind plant no longer wants to produce. NYISO's Security Constrained Economic Dispatch software (SCED) can accommodate both zero and/or negative offers and prices in its algorithm. NYISO evaluates all generator offers, including wind, and the load forecast to produce a least-cost dispatch solution every 5 minutes. If NYISO is transmission constrained, NYISO will select the most economic solution for curtailment.

During unconstrained operation, wind plants will operate as normal and be paid for all their output, as per the NYISO special market rules for renewables. When the wholesale markets first opened, NYISO created special market rules for intermittent renewable resources that exempt wind and run-of-river hydro units from financial penalties for deviations from expected schedules, up to a maximum installed capacity of eligible renewable energy capacity. The initial cap on the total amount of renewable resources that could operate under the special market rules was set at 500 MW, but was increased to 1,000 MW in 2006 and to 3,300 MW in 2008.

During constrained operating periods, NYISO will provide an electronic re-dispatch signal arising from its market-based economic solution. The least-cost economic solution will be calculated from all generation offers, including wind plant offer curves. The price-quantity offers submitted by each wind plant will determine the basepoint amount set for each plant. If they are not fully economic, wind plants must follow the re-dispatch signal and meet the basepoint output limit within 5 minutes. Wind plants will be paid for their output at or below the re-dispatch basepoint. If a wind plant does not respond to the market basepoint and reduce output accordingly, a financial penalty will apply. The penalty structure is as follows:

*MWs above basepoint * Regulation Clearing Price*

NYISO allows a 3% bandwidth margin for error, based on the wind plants' upper operating limit.

Bonneville Power Administration

As of March 2009, BPA has over 2,000 MW of installed wind power capacity connected to its 10,500 MW peak load balancing area, and expects that amount to double within the next 2 to 3 years. BPA expects to experience wind penetration rates by capacity of up to 30% in 2009, with projections of up to 39% penetration by 2010 (see Figure 4).[18] Additionally, many of the wind projects are in the same general area, the Lower Columbia region, which means wind generation tends to move up and down together, leading to large swings in wind generation. To date, BPA has provided balancing from its hydro plants, but with the projected addition of wind power projects in the next two years, the ability of the hydro system to balance the BPA grid is becoming more limited. A lack of sub-hourly markets in the Pacific Northwest also makes wind integration more difficult.

In July 2008, a large increase in wind power taxed the availability of BPA's balancing reserves and BPA's calls to wind producers to request curtailment mainly reached answering machines. BPA succeeded in getting only one wind farm to curtail production.[19] Since this occurrence, BPA has implemented new procedures and communications systems, and has had full compliance whenever BPA has called on wind plants to limit output. BPA is working with other regional stakeholders through the Wind Integration Team (WIT) on integrating increasing amounts of wind energy into the transmission grid by:

- Building (and financing) new transmission to interconnect remote renewable resources to load centers;
- Revamping the way BPA operates its grid to work with large amounts of variable generation; and
- Creating new wind energy-friendly business practices and working with other utilities across the Western Interconnection to find regional solutions.

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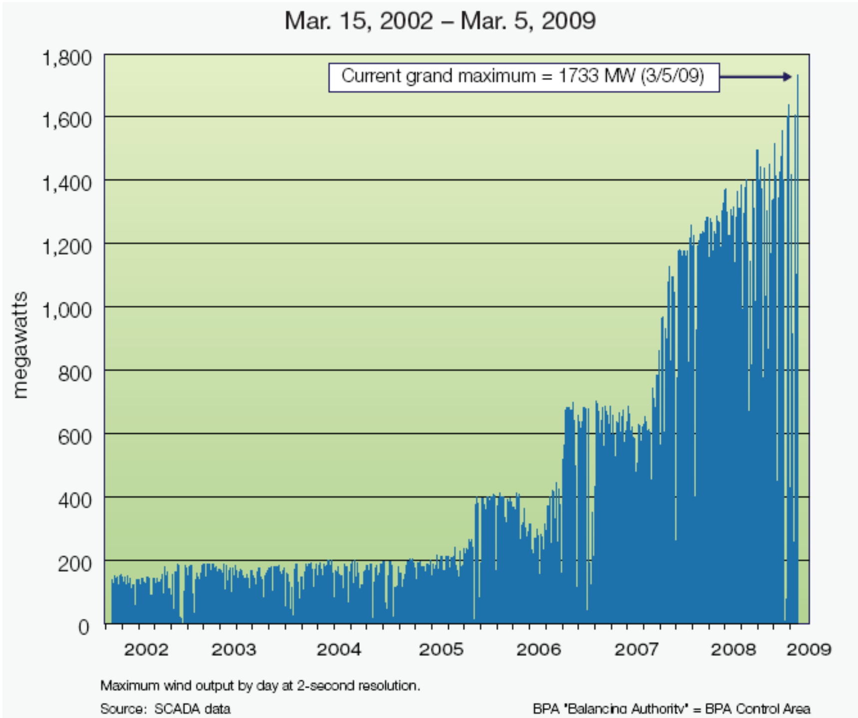
[18] Silverstein, Brian, Bonneville Power Administration, "Integrating Renewable Resources Into the Electric Grid," presentation before the FERC Technical Conference on Integrating Renewable Resources into the Wholesale Electric Grid, March 2, 2009.
[19] Kinsey Hill, Gail, "Wind power surge forces BPA to spill at Columbia Basin dams," The Oregonian, July 5, 2008, http://www.oregonlive.com/environment/index.ssf/2008/07/columbia_basin_river_managers.html.

Figure 4.

Wind Generation in BPA: March 2002 – March 2009



Source: Bonneville Power Administration, *How BPA Supports Wind Power in the Pacific Northwest,* BPA Fact Sheet, March 2009, http://www.bpa.gov/corporate/pubs/fact_sheets/09fs/BPA_supports_wind_power_for_the_Pacific_Northwest_-_Mar_2009.pdf.

The WIT established a new Work Plan in early 2009, focusing primarily on the following critical areas:

1. New operating protocols − BPA has already established protocols in Dispatch Standing Orders to limit variable generators, as outlined in the Wind Integration Team's report.[20] This approach for dealing with over-generation (and other situations) has been incorporated into their Large Generator Interconnection Agreements for variable resources. In over-generation situations, balancing reserves will be utilized first to restore the load and generation balance. However, after 90% of all balancing reserves are deployed, BPA may require variable generators such as wind plants to limit wind output in order to reduce excess generation or curtail schedules to actual generation plus a reserve allocation. In such situations, variable generators are assigned a maximum generation limit based on their scheduled output plus a proportional allocation of balancing reserves. The following protocols will be used to limit variable generators when 90% reserve deployment is reached:

[20] Bonneville Power Administration, *Connecting Variable Generating Resources to the Federal Columbia River Transmission System (FCRTS),* January 29, 2009, http://www.bpa.gov/corporate/windpower/docs/Connecting_Variable_Generating_Resources_to_Grid_Mar_5_final.pdf.

- Variable generators that have substantially over-generated relative to their schedule will be required to reduce generation to a specified level.
- Variable generators that have substantially under-generated relative to their schedule will have schedules curtailed to actual levels plus the allocated amount of reserve.[21]

BPA is also automating its dispatch process to signal variable generation operators to feather their turbines to comply with an order to reduce generation within ten minutes. If a variable generator fails to respond to three orders within a two-year period, BPA requires automatic generation control equipment to be installed at the site to allow BPA to send a generation limit directly into the wind facility's controlling computer.

BPA has also launched an Internet application known as Generation Adviser to monitor the current balancing reserves limit, the amount of balancing reserves that are in use, and certain limit and curtailment alarms. A warning alarm will sound if either incremental or decremental (i.e., inc or dec) balancing reserves exceed 85% for 30 seconds continuously, and a limit alarm if 90% or more of the inc or dec balancing reserves are in use for 30 seconds continuously.

2. Wind forecasting − BPA and wind operators are also working to create a more accurate wind forecasting system to provide more up-to-the-minute scheduling data for dispatchers. BPA is installing 14 additional meteorological devices to assist the wind operators and forecasting companies in creating better forecasts of wind output. BPA plans to begin within-hour in-house wind forecasting by May 2010.

3. Sub-hourly scheduling pilot − BPA is developing systems and processes that will enable schedule changes on a sub-hourly basis. Market participants will be able to schedule excess wind generation from the BPA balancing area on the half-hour, making it possible for excess power that may have needed to be limited, to be sold instead. By December 2009, BPA plans to start offering reservation and transmission scheduling and power exports on half-hour intervals for the excess energy.

4. Dynamic transfer limits study − BPA is working with other utilities to develop new power dispatch protocols and scheduling systems so that BPA-region wind plants can be electronically controlled and supported by adjoining balancing authorities. This work will begin with a comprehensive study to evaluate the criteria and necessary requirements on four specific paths; the Northern Intertie, Southern Intertie, Idaho to Boardman, and Libby to Garrison.

5. Customer supplied generation imbalance − Some wind plant owners have expressed interest in self-supplying some capacity reserves to reduce their reliance on BPA

[21] Silverstein, Brian, Bonneville Power Administration, "Integrating Renewable Resources Into the Electric Grid," presentation before the FERC Technical Conference on Integrating Renewable Resources into the Wholesale Electric Grid, March 2, 2009.

reserves (and associated charges). BPA will begin examining systems and processes that could be implemented by October 2010 to allow customers to supply a portion of their own generation imbalance service either from their own resources or through contracts with other resource owners.

6. Third-party supply pilot − BPA is proposing to examine balancing area reserve augmentation through the use of third party supply of within-hour balancing reserves that would respond directly to BPA's Automatic Generation Control signal.[22]

Midwest Independent System Operator

The Midwest Independent System Operator (ISO) has over 6,500 MW of wind capacity and total installed generation capacity of over 159,000 MW. A new wind outpeak record of 5,280 MW was set on September 28, 2009. In late 2008, the Midwest ISO formed the Minimum Generation Task Force (MGTF), a stakeholder process to examine minimum generation situations and provide input, policy guidance, and recommendations on how to best mitigate and deal with issues that arise during surplus situations. The Midwest ISO reported 17 minimum generation events in 2008, a significant increase over past years.[23] The Midwest ISO speculates this is partly due to the increasing levels of wind energy in the Midwest ISO footprint and a decrease in the ability of certain baseload coal units to be able to reduce generation as a result of the addition of NO_x controls.[24]

The MGTF has evaluated previous minimum generation events and continues to evaluate new events as they occur. The MGTF is in the process of developing recommendations for changes to grid operating procedures and market rules that may help mitigate the impacts of and/or reduce the frequency of future minimum generation events. Possible items to be reviewed may be how import and export schedules are treated (including ramp limit adjustments) during supply surplus situations, an examination of how to better utilize price signals or LMP adjustments leading up to an event, and possible changes to the market rules associated with intermittent resources.[25] At an MGTF meeting on May 27, 2009, there was discussion of potential tariff changes to mitigate the key drivers of minimum generation events. These drivers include the persistence of price signals (e.g., imports/exports, economic/emergency minimum prices, and pumped storage, etc), the unit commitment process (timing and amount), wind generation (e.g., more in real time than was cleared in the day ahead market), and forecast errors (load and wind generation). The priority is on getting the price signals correct during Minimum Generation Events and then letting the market work.

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[22] BPA, Work Plan cover letter, June 16, 2009, http://www.bpa.gov/corporate/WindPower/docs/Work_Plan_cover_letter,_June_16,_2009.pdf.
[23] Midwest ISO, *Forecast Accuracy & Impact of Min Gen Events*. November 5, 2008, http://www.midwestiso.org/publish/Folder/45e84c_11cdc615aa1_-7eb10a48324a?rev=2.
[24] Midwest ISO, *Midwest ISO Stakeholder Governance Guide, Appendix E, Proposal For Minimum Generation Task Force*. October 15, 2008 (draft), http://www.midwestiso.org/publish/Document/45e84c_11cdc615aa1_-7c560a48324a?rev=1.
[25] *Ibid.*

The Midwest ISO's Emergency Operating Procedures include protocols for supply surplus events. A Minimum Generation Emergency Alert is issued if system load and interchange are expected to fall to within 2,000 MW of minimum non-emergency scheduled supply. This alert initiates reviews of unit commitment and dispatch operations, and asks generation operators to verify preparedness to operate at emergency levels. A Minimum Generation Emergency Warning is issued if system load and interchange are expected to fall below the non-emergency minimum. A Minimum Generation Emergency Event (Min Gen) is declared when the short-term forecasted load and interchange falls below non-emergency supply. This allows the Unit Dispatch System to utilize the emergency range of online resources. If this action is insufficient, generation may be de-committed. In March 2009, the Midwest ISO implemented a "short term" interpretation of the current Min Gen curtailment procedures to mean that resources with the "shortest restart time" (i.e., variable resources such as wind) are always curtailed first when an event stage is reached and the emergency ranges in the first phase of the event stage are not sufficient. A Min Gen event occurred on June 1 that lead to intermittent resources being curtailed at 4:05 AM for about two and a half hours. The event was declared at 1 AM and by 4 AM the Midwest ISO had reduced all their conventional units to minimum emergency dispatch levels. The Midwest ISO then asked for 100 MW of intermittent resource curtailments pro rata across the on-line units.

In early May, the MGTF approved non-tariff changes to the Emergency Operating Procedure for Supply Surplus (RTO-EOP-003, Min Gen) that include a curtailment sequence which comes close to treating wind similar to other technologies. If curtailments are required, de-commitment of generation or reduction in scheduled generation will be executed in the following order:

1. Generation identified in the Reliability Assessment Commitment process.
2. Generation above the day-ahead schedule from non-DNRs (designated network resources).
3. Generation above the day-ahead schedule from DNRs.
4. Non-DNR committed in the Day Ahead Market.
5. DNRs and firm imports committed in the Day Ahead Market.[26]

Within each of these groups, the generation shall be de-committed in reverse economic order regardless of the type of resource. The procedure changes were presented to the Market Subcommittee and the Reliability Subcommittee and are now in the next step of the Procedure Review Process. As currently written, this version of the Supply Surplus Procedure would replace the "short term" interpretation that disadvantages intermittent resources.

The Midwest ISO has a separate set of procedures if generation curtailment is necessary because of transmission congestion. If a generator is coming online but is not yet considered commercial, test energy will be curtailed first before LMP Binding Procedures and Transmission Loading Relief (TLR) are imposed. If transmission congestion is local and not impacted by any other generator, then wind is normally curtailed on a pro-rata basis by order of transmission priority. If the transmission congestion is regional and can be addressed or is impacted by other

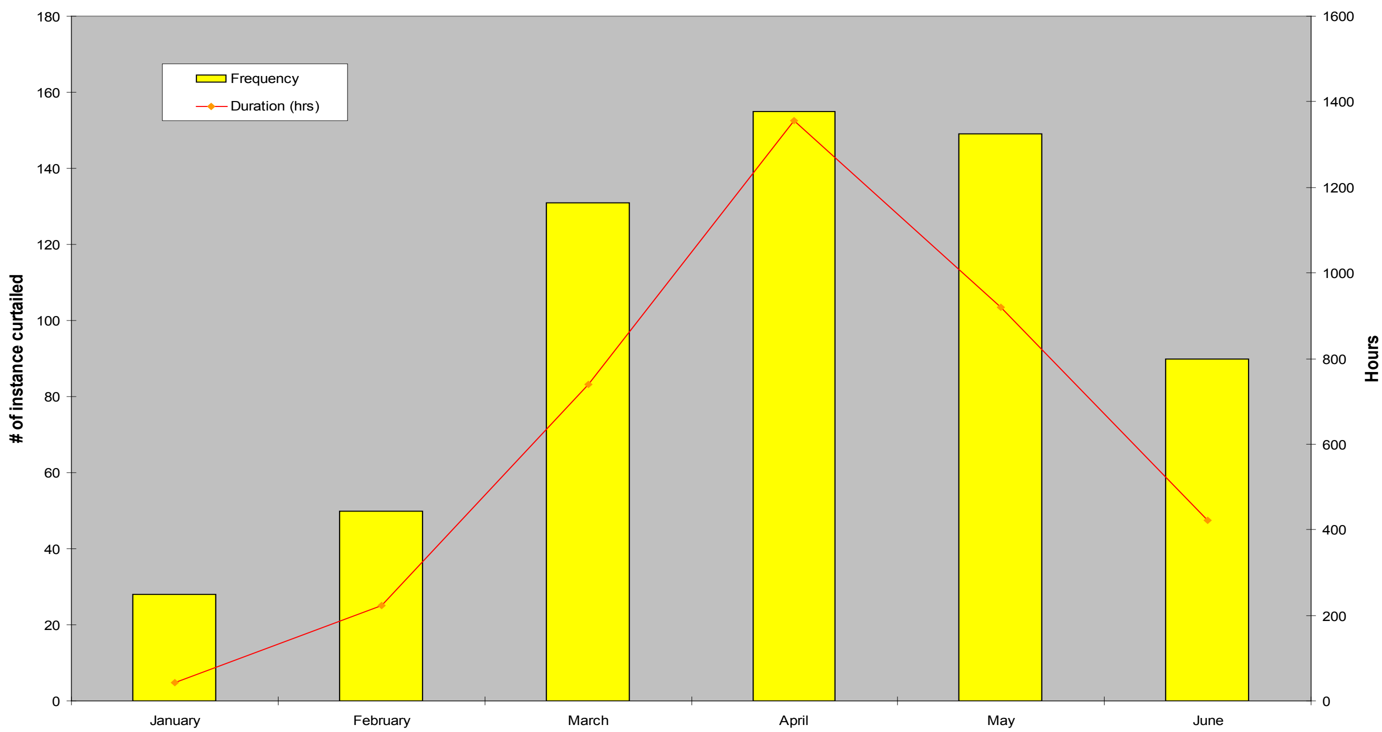
[26] Midwest ISO, *Midwest ISO Supply Surplus Procedures,* RTO-EOP-003-R9, effective date: January 6, 2009, redline version, not yet fully approved or implemented, accessed June 8, 2009.

generators, the TLR process is used first. If that does not provide sufficient relief, then wind may be manually curtailed on a pro-rata basis in order of transmission priority.

Figure 5 presents the number of hours and instances that the Midwest ISO has curtailed wind between January and June of 2009. Note that because the data includes multiple wind facilities, the total number of curtailed hours may exceed the hours in a month.

Figure 5.

Frequency and Duration of Wind Curtailment in the Midwest ISO January – June 2009



Source: Midwest ISO, "Wind Resources—Underutilized Flexibility," presentation before the Midwest ISO Wind Workshop, September 29, 2009, http://www.midwestiso.org/publish/Document/6b6059_1239ec7b046_-78210a48324a/Underutilized_Wind_Flexibility.pdf?action=download&_property=Attachment.

Hawaiian Electric Company

The Hawaiian Electric Company (HECO, serves Oahu) along with its subsidiaries, the Hawaii Electric Light Company (HELCO, serves the Big Island) and the Maui Electric Company (MECO, serves Maui, Lanai, and Molokai) provides electricity service to most of the Hawaiian Islands. Installed capacity in the control areas as of August 2008, was:

- HECO – approximately 1,800 MW (no installed wind energy at this time).
- HELCO – approximately 300 MW plus about 33 MW of wind.
- MECO – approximately 280 MW plus about 30 MW of wind.[27]

Being islands, the Hawaiian electric systems are relatively small isolated grids without any interconnections. The small grid size along with the generation mix results in a relatively small frequency bias. In 2008, peak load was 198.2 MW for HELCO and 199 MW for MECO. All three islands are evening peaking utilities and demand has dropped since 2008. The daytime peak is presently running around 160 MW for HELCO and evening peaks are about 170 MW for HELCO and in the 180's for MECO. Minimum load is approximately 50% of the evening peak, typically between 80 to 90 MW. Due to a combination of factors including limited geographic area; lack of interconnections, degree of volatility in output second to second, sustained ramps by the wind plants, and (for HELCO) a large amount of non-flexible generation from hydro and geothermal resources, integration of the wind plants onto the MECO and HELCO systems have presented challenges for system balancing and frequency control. In addition, the low minimum load coupled with the large amount of as-available resources and must-take generation (particularly from the geothermal facility for HELCO and the biomass facility for MECO), creates excess energy problems during lower-load periods.

Primary system balancing and frequency control is provided by the conventional generating units through droop response. On a longer time scale, with a 4-second control cycle, automatic generation control provides supplemental frequency control and economic dispatch.

The two newer wind plants on the HELCO system and the 30-MW plant on the MECO system are equipped with grid operator-controlled curtailment interfaces that allow the operator to issue a set point that limits the output of the wind plant to no more than the set amount. HELCO uses generation curtailment, from wind or from other generating plants, in two general circumstances:[28]

1) System events where there is a system problem that is best addressed through reduction in a plant's output – In such a case, the most effective control to address the system problem is employed, which may include reduction of a wind plant's output through curtailment. Examples include:

    - Transmission line overload conditions (congestion) – The most effective control for the particular overload is employed, which may be curtailment of a wind plant or a conventional generator.

    - The transmission line is open and cannot close due to excessive phase angle – This would require reduction in power flow at a particular point on the system.

    - Fast time-scale variability of a particular wind plant is causing system frequency to deviate – Curtailment of that plant is used as a means to reduce the variability.

[27] Hawaiian Electric Company Fact Sheet, "Power Facts," August, 2008, http://www.heco.com/vcmcontent/StaticFiles/pdf/01_01_PowerFacts.pdf.
[28] Information in this section is from a personal communication with Lisa Dangelmaier, Hawaiian Electric Company, January 28, 2009.

Due to the manner in which curtailments are effected at the wind plant through the controls, the curtailment has the effect of smoothing the output.

2) Conditions of excess generation – Transmission-side as-available generation suppliers, including wind power suppliers, are curtailed according to a pre-determined priority that was established at the time of the contract agreement. Prior to curtailment for excess energy, HELCO and MECO will reduce output of the must-run generation to minimum levels, taking into consideration regulating reserve requirements (for down regulation). If time permits, intermediate units are then taken off-line, with consideration given for load demand changes, observed variability of wind output and the minimum down time for bringing these intermediate units back on-line. This is the primary cause of the majority of curtailments of wind energy on the HELCO and MECO systems.

Xcel Energy

Xcel Energy has utility operations in three separate regions through its regulated subsidiaries: the Public Service Company of Colorado (PSCO) serving portions of Colorado; the Southwestern Public Service Company (SPS) serving portions of New Mexico and Texas; and the Northern States Power Company with divisions in Minnesota and Wisconsin. The Northern States Power Company (NSP) is a part of the Midwest ISO. As of 2008, Xcel Energy has almost 1,300 megawatts of wind energy capacity in Minnesota, North Dakota and South Dakota, with the majority of this generation concentrated in southwestern Minnesota. Transmission issues in this region resulted in the regional curtailment of approximately 23,000 MWh of wind generation in 2008, at the direction of the Midwest ISO. Xcel Energy has an agreement with the wind generators in southwestern Minnesota establishing responsibility for curtailment on a rotational basis between the various plants (see Table 3).

Table 3.

Minnesota Wind Projects Participating in Xcel Energy's Wind Curtailment Rotation (as of 2007)

Wind Plant	Capacity (MW)
Lake Benton Power Partners I	107.25
Lake Benton Power Partners II	103
Chanarambie Power Partners	85.5
Moraine Wind	51
Northern Alternative Energy	27*
Norgaard	8.75**
Total	**382.5**

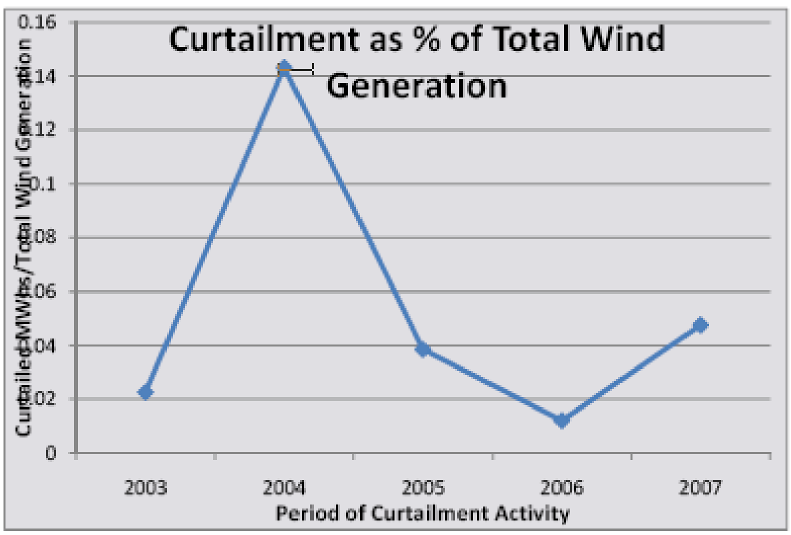
* Consists of several facilities below 2 MW
** Consists of seven 1.25-MW facilities

Source: Minnesota Public Utilities Commission, *Report to the Legislature on Wind Curtailment Payments under Minnesota Statutes §216B.1681,* July 2008, http://www.puc.state.mn.us/portal/groups/public/documents/pdf_files/000805.pdf.

Wind plants that are curtailed are made whole by Xcel Energy, covering both the lost value of the federal production tax credit (PTC) and energy. Wind generation has been continuously curtailed in this area since 2004, when nearly 14% of wind generation had to be curtailed. New transmission as part of the Southwestern Minnesota transmission project in late 2004 helped decrease the level of wind curtailment after 2004. From 2005 to 2007, nearly 5% of Xcel Energy's Minnesota wind generation was curtailed each year (see Figure 6). Wind curtailment increased slightly in 2007 as existing transmission facilities had to be taken out of service to allow continued construction of the Southwestern Minnesota transmission facilities.[29] For 2008, Xcel Energy estimated it curtailed about 23,000 MWh in the Midwest ISO's service territory.[30]

Figure 6.

Curtailment as a Percentage of Total Wind Generation for Xcel Energy in Minnesota 2003-2007



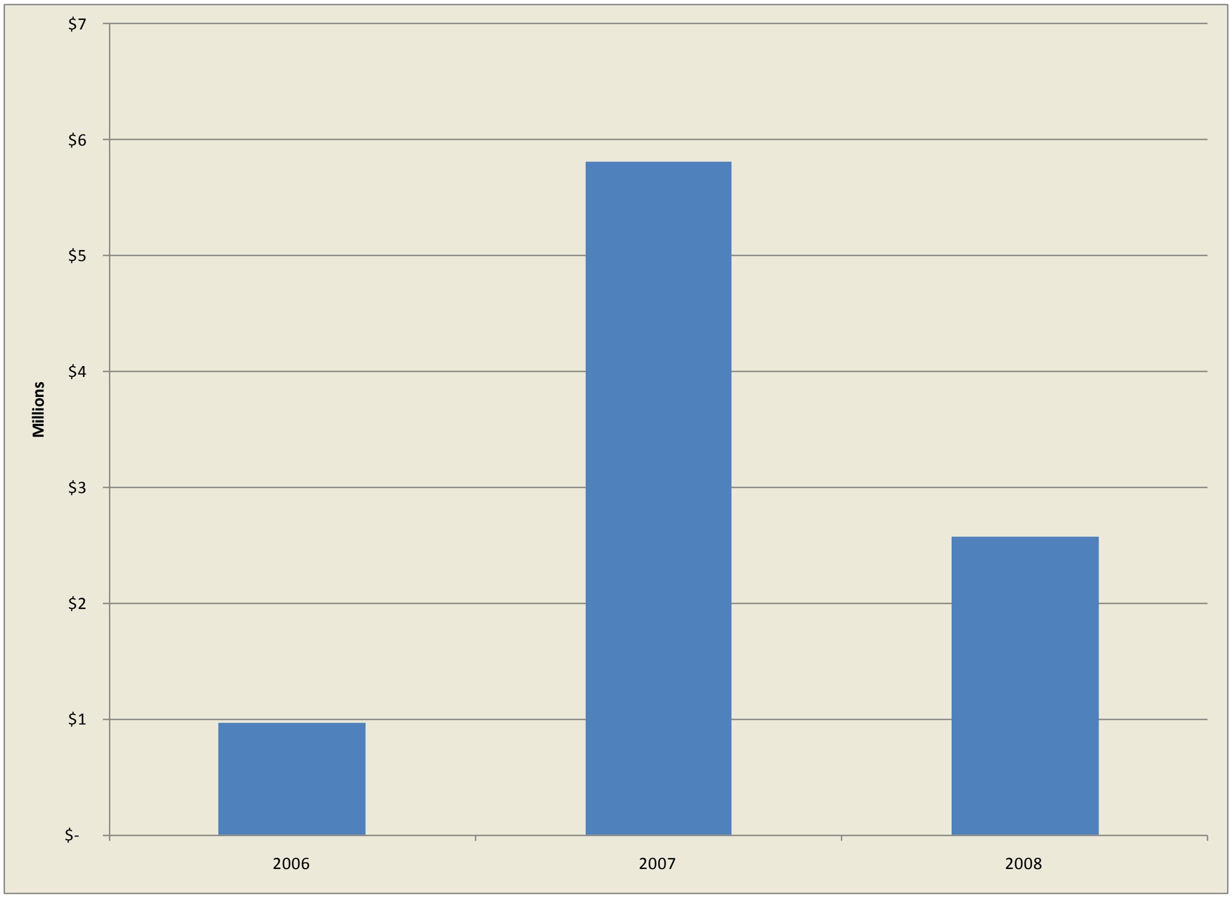
Source: Minnesota Public Utilities Commission, *Report to the Legislature on Wind Curtailment Payments under Minnesota Statutes §216B.1681,* July 2008, http://www.puc.state.mn.us/portal/groups/public/documents/pdf_files/000805.pdf.

Figure 7 shows Xcel Energy's annual wind curtailment payments in Minnesota. Total wind curtailments began at below $1 million in 2006, then increased sharply to nearly $6 million in 2007 before decreasing to about $2.5 million in 2008. As noted earlier, the large increase in wind curtailment payments in 2008 is likely due to taking some transmission facilities out of service to allow construction of transmission facilities in southwestern Minnesota.

[29] Minnesota Public Utilities Commission, *Report to the Legislature on Wind Curtailment Payments under Minnesota Statutes §216B.1681,* July 2008, http://www.puc.state.mn.us/portal/groups/public/documents/pdf_files/000805.pdf.
[30] Personal communication, Tom Ferguson, Xcel Energy, May 12, 2009.

Figure 7.

Annual Wind Curtailment Payments in Minnesota by Xcel Energy 2006 – 2008

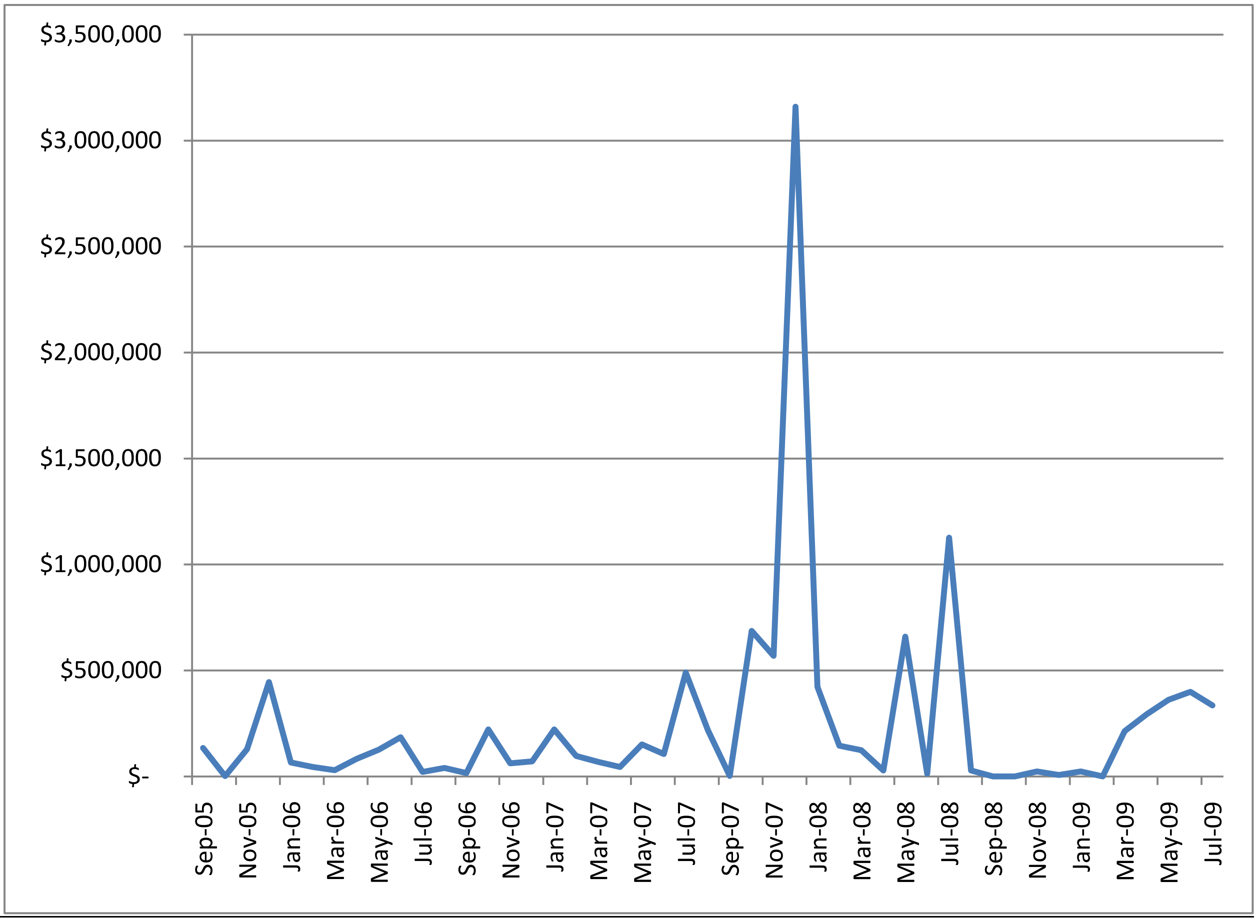


Source: Xcel Energy Monthly Fuel Adjustment Charge Reports, as filed with the Minnesota Public Utilities Commissions.

Figure 8 presents Xcel Energy's monthly wind curtailment payments between September 2005 and July 2009. The monthly wind curtailment payments were generally below $500,000 with some large jumps in December 2007 and in July 2008.

Figure 8.

Monthly Wind Curtailment Payments in Minnesota by Xcel Energy September 2005 – July 2009



Source: Xcel Energy Monthly Fuel Adjustment Charge Reports, as filed with the Minnesota Public Utilities Commissions.

The PSCO and SPS (which is in the Southwest Power Pool) regions operate under a separate policy. Under this policy, eight steps must be taken before any wind generation is curtailed, including backing down gas and coal generation to minimums, lowering power purchases and increasing sales, and reducing sales prices to $0.[31] In Colorado, Xcel Energy had 1,060 MW of wind energy as of the end of 2008, and has a contractual arrangement with the Logan Wind plant to provide up to 14,000 MWh of annual curtailment at no cost. A number of other wind generators have similar contracts for less amounts of energy, and are curtailed after Logan, followed by curtailment of energy purchases. After these steps are exhausted, wind generation may be curtailed outside of these no-cost agreements, with Xcel Energy paying for

[31] Xcel Energy, Generation Plant Reliability, *Wind Dispatch Policy*, Revision 1.2, http://www.xcelenergy.com/SiteCollectionDocuments/docs/CRPExhibit5OperatingProcedures.pdf.

the energy it is not receiving as well as the federal PTC. The choice of which plants are curtailed is predetermined by a schedule based on the day of the month. In Colorado, Xcel Energy curtailed about 3,000 MWh of wind generation in 2008. [32]

Southern California Edison[33]

Southern California Edison (SCE) has approximately 700 MW of wind generation in the Tehachapi region. The primary transmission path to the Tehachapi region is the Goldtown-Lancaster 66-kV line, which often becomes overloaded. The lack of adequate transmission has forced SCE to curtail wind production to reduce loading on the line. SCE has an agreement with Terra-Gen Power, which operates about 187 MW of wind power in the region, to curtail production when the need arises. SCE then makes payments for this service by covering the lost energy, though not the federal PTC. SCE estimates that it is forced to curtail about 15 MW of wind generation for 3 or 4 hours every two days.[34] The development of the $2 billion Tehachapi transmission project that can access up to 4,500 MW of wind power will significantly ease the need for wind curtailment. The first phase of the Tehachapi transmission project could come on-line as early as this year (2009).

[32] All estimates for PSCO are from personal communication, Tom Ferguson, April 24, 2009.
[33] Southern California Edison did not review this profile. The information presented here is based on the authors' understanding of how wind curtailment is done in Southern California Edison's service territory.
[34] Personal communication with Southern California Edison personnel, May 2009.

III. Wind Power Curtailment Examples outside the United States

Alberta Electric System Operator[35]

The Alberta Electric System Operator (the AESO) began studying the integration of wind into their system in 2004. Studies performed in 2005 and 2006 indicated that the AESO did not have the procedures in place to be able to accommodate the increasing amounts of wind power being planned in Alberta. The AESO is a fairly isolated system with limited interconnections to grids outside Alberta, and therefore a limited ability to share balancing services. Additionally, the generation in the AESO is mainly large baseload coal-fired plants along with a significant amount of cogeneration. In 2006, the AESO placed a temporary cap of 900 MW of wind capacity on their grid. The AESO's peak load is approximately 9,700 MW; therefore, the temporary cap represented about 9% total wind penetration by capacity. Current wind capacity on the AESO system is approximately 500 MW, more than 5% of peak load by capacity. There is more than 11,500 MW of additional wind power projects in the AESO's interconnection queue.[36]

Under the (AESO's) Operating Policy and Procedure 103 (OPP 103), "Dispatching Multiple $0 Offers," wind generation is exempt from curtailment because such generation is of "undetermined or uncertain minimum stable generation." Wind power is a non-dispatchable resource, along with cogeneration and some baseload units that are must-run, that does not submit offers into market. Wind power is accepted as delivered and treated as a price taker supplying energy to the market at a $0 bid price. Therefore, wind power is only curtailed to manage transmission constraints and other reliability events. Figure 9 shows the amount of dispatchable capacity on the AESO system, which can vary from 1,000 to 3,000 MW in a one-week period. Capacity available for dispatch includes unloaded capacity from regulating reserves as well as generation offers not included as must-run baseload.

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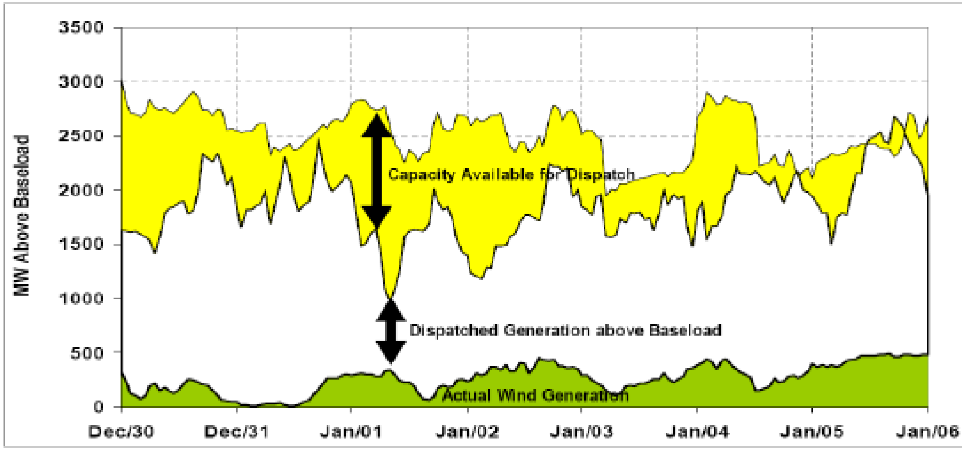
[35] The Alberta Electric System Operator did not review the information in this section. The information presented here is based upon the authors' understanding of how the Alberta Electric System Operator uses wind curtailment.
[36] Alberta Electric System Operator, *Implementation of Market & Operational Framework For Wind Integration in Alberta,* March 2009, http://www.aeso.ca/downloads/WI_Paper-_Final.pdf.

Figure 9.

The AESO Dispatchable Generation



Source: Alberta Electric System Operator, *Implementation of Market & Operational Framework For Wind Integration in Alberta,* March 2009, http://www.aeso.ca/downloads/WI_Paper-_Final.pdf.

The Energy Market Merit Order (EMMO) is the AESO electricity market control software and consists of all the offers and bids for supply and demand that is sorted in order of offer and bid price blocks and dispatched in relative economic order. Generation that is subject to curtailment is divided into two groups; inflexible and flexible generation. When the EMMO receives a quantity of $0 bids indicating that supply exceeds demand, flexible generation is curtailed by an amount related to its contribution to the power supply. If this is not enough to achieve balance, imports will be curtailed, followed by reductions of inflexible generators to their respective minimum generation levels. In September 2007, the AESO released the Market and Operational Framework (MOF) study for wind integration.[37] The study recommended that the AESO develop a wind forecasting system, procure more regulating reserves and that wind generators should be subject to wind power management (WPM). Under WPM, wind power facilities would be required to have the capability to reduce output. WPM includes on-site power management such as curtailment, power limiting, and ramp limiting. WPM will be integrated with the current EMMO, regulating services, and load and supply following services, allowing wind power the opportunity to participate in providing these services, along with conventional generators. When other measures are insufficient to absorb forecasted or actual wind generation, WPM will be used to curtail wind power. Three work groups (i.e., Supply Surplus Protocol, Wind Power Management Protocol (WPMP), and Wind Power Management technical requirements) are studying how to implement the MOF. Wind generators will be responsible for the costs of wind forecasting and any equipment associated with WPM. In addition, wind generators will not be compensated for lost production due to curtailment.

[37] Alberta Electric System Operator, *Market & Operational Framework For Wind Integration in Alberta,* September 26, 2007, http://www.aeso.ca/files/MOF_Final__Sept26.pdf.

An August 2008 report by the WPMP supply surplus working group suggested changes to OPP 103 in order to implement the MOF.[38] The proposal suggests that OPP 103 should be amended to no longer exempt wind generation from being power limited. The work group suggested a sharing of the burden of curtailments between inflexible, flexible, and wind generation. The WPMP report recommends an adoption of a system similar to ERCOT where the AESO will use data from EMMO, ancillary services requirements, load and wind power forecasts, and measurements of potential MW availability from operating wind projects to calculate a System Wind Power Limit (SWPL). The SWPL amount will then be allocated amongst the wind power generators on a pro rata basis. The WPMP also recommended that wind curtailment be re-assessed and re-allocated every 20 minutes if the limit for any one wind project changes by more than 5 MW.

The first set of recommendations for implementing WPM was released by the Market and Operational Framework working group in March 2009.[39] The recommendations include rules, practices and procedures, and requirements need to implement the MOF. These recommendations are:

- *Wind power forecasting requirements*: The MOF working group recommends procuring a centralized wind forecasting system, starting a stakeholder process to define a set of rules, procedures, standards, and technical requirements for data and communications protocols, establishing a data management system, and making aggregated wind forecasts available to market participants.

- *Wind power curtailment protocol*: The MOF working group recommends adopting the WPMP recommendation on how to allocate system wind power limits to individual facilities. The working group proposed the Potential MW Capability approach, a pro-rata allocation of system-wide wind curtailments based on the current MW capability of each wind plant, with reassessments and re-allocations every 20 minutes if the limit for any one wind plant has changed by more than 5 MW.

- *Supply surplus protocol*: The MOF working group recommends including wind facilities in operating procedures, developing a minimum operating level for wind plants, and developing a market notification system for notifying generators of supply surplus conditions to encourage voluntary curtailment actions.

In June 2009, the AESO issued its final recommendations concerning the MOF. The AESO supports implementing centralized wind forecasting and plans to issue an RFP for wind forecasting services. The AESO also intends to develop requirements for wind generators to submit wind and turbine data that would be necessary inputs for the AESO centralized wind forecast, and to publish and make available to market participants aggregated wind forecasts. The AESO also will pursue a rule development process for implementing WPM and endorsed

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[38] Alberta Electric System Operator, *Wind Power Management Protocol for Alberta: Wind Power Management Work Group Recommendation to the Alberta Electric System Operator,* August 15, 2008, http://www.aeso.ca/downloads/WPM_Protocol_Work_Group_Paper.pdf.

[39] Alberta Electric System Operator, *Implementation of Market & Operational Framework For Wind Integration in Alberta,* March 2009, http://www.aeso.ca/downloads/WI_Paper-_Final.pdf.

the SWPL methodology. The AESO said it will first use EMMO and then use available ancillary services before turning to WPM.[40]

The WPMP is also working on a set of congestion management protocols where WPM can be integrated into real-time system operations to curtail wind power when necessary during times of transmission congestion. In September 2007, the AESO removed the limit on wind power and is in the process of developing transmission system upgrades to accommodate additional wind power projects in the Province – the 240-kV Pincher Creek to Lethbridge transmission line to interconnect up to 1,000 MW of wind in the southwest; a 240-kV southern loop to interconnect up to 2,700 MW of wind over next 10 years; and scoping for new facilities in central Alberta (Hanna area) to interconnect up to 1,400 MW of wind.[41]

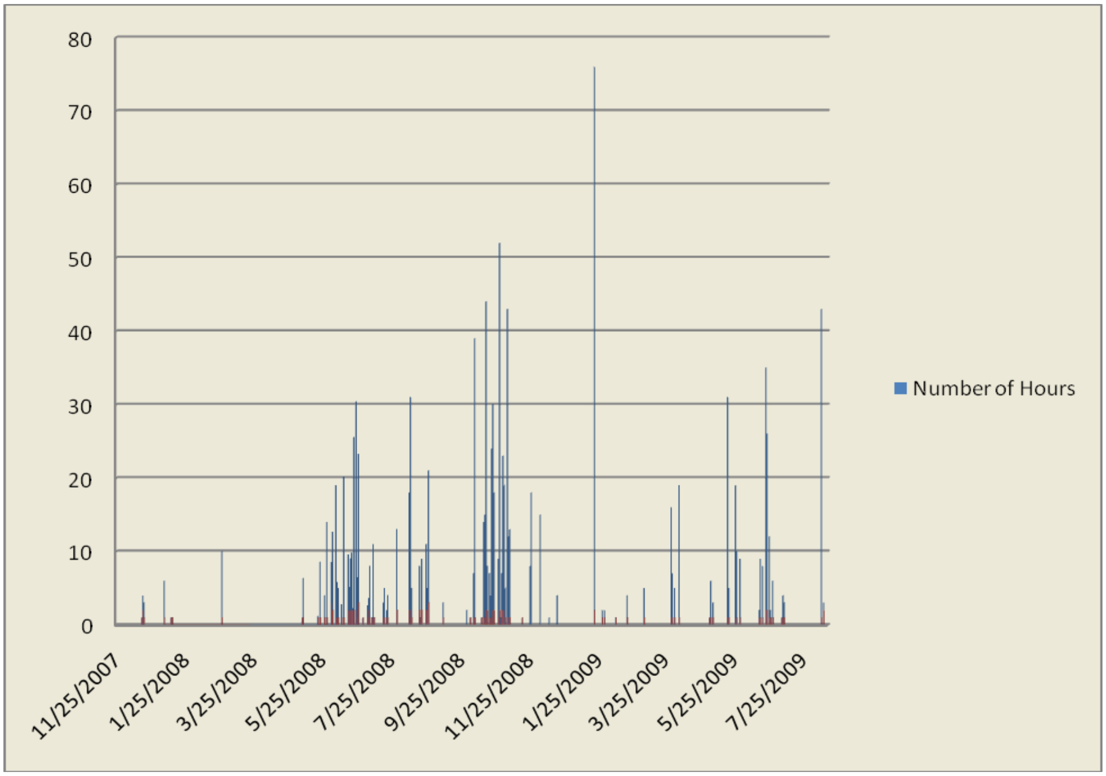
The AESO plans to continue stakeholder consultations and expects that its market rule will change over the next few years as the market continues to evolve and adapt to the additional wind generation in Alberta.

Figure 10 presents the number of hours per day at the number of wind facilities that the AESO curtailed, from November 2007 through mid-August 2009. The number of hours that AESO curtailed wind was higher in the spring and fall, with one noticeable spike to over 70 hours in January 2009.

[40] Alberta Electric System Operator, *Final Recommendations Regarding Implementation of Market and Operational Framework for Wind Integration in Alberta and AESO Response to Stakeholder Comments*, June 18, 2009, http://www.aeso.ca/downloads/MOF_stakeholder_comments_and_AESO_response_matrix_cover_letter.pdf.
[41] Alberta Electric System Operator, "Implementation of Market & Operational Framework for Wind Integration," presentation at Stakeholder Information Session, March 23, 2009, http://www.aeso.ca/gridoperations/17383.html.

Figure 10.

Number of Hours of Wind Curtailment by Day by the Alberta Electric System Operator November 2007 – July 2009

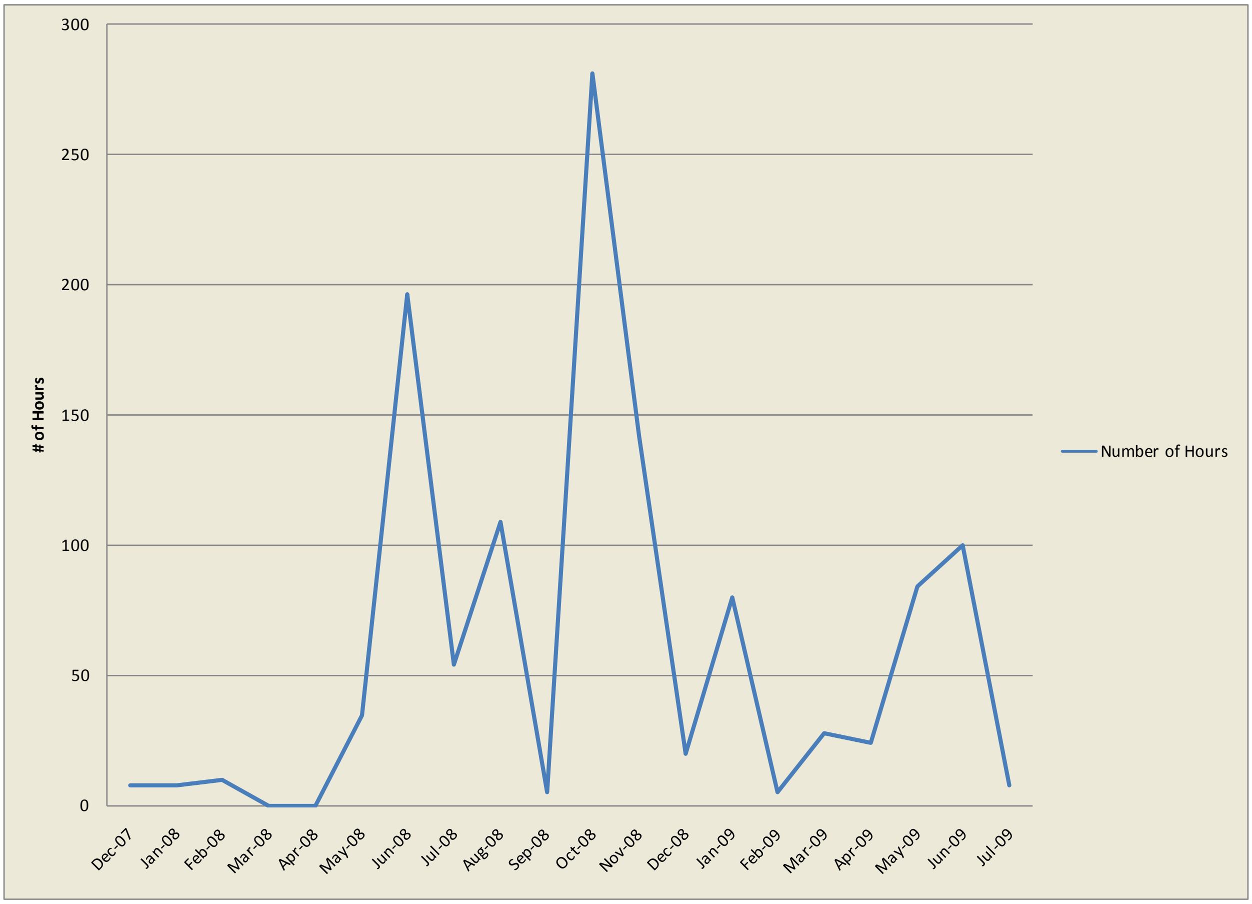


Source: Alberta Electric System Operator, "Weekly Wind Power Operational and Market Reports," http://www.aeso.ca/gridoperations/14246.html.

Figure 11 shows the number of hours by month that AESO curtailed wind generation. Again, the spring and fall months showed jumps in wind curtailment, with some increases in wind curtailment some winter months as well.

Figure 11.

Number of Hours of Wind Curtailment by Month by the Alberta Electric System Operator December 2007 – July 2009

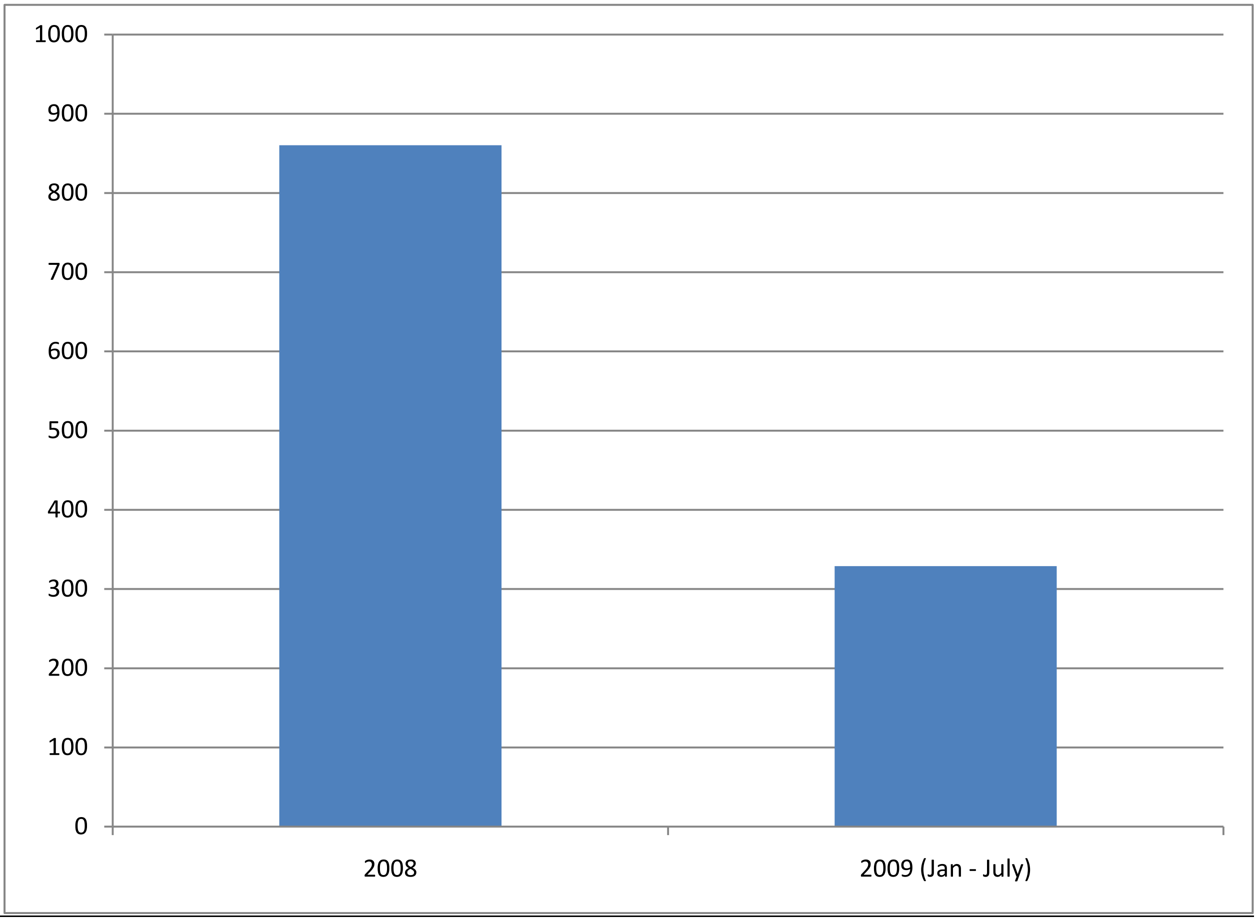


Source: Alberta Electric System Operator, "Weekly Wind Power Operational and Market Reports," http://www.aeso.ca/gridoperations/14246.html.

Figure 12 depicts the number of hours wind energy projects were curtailed in Alberta in 2008, and the number of hours that wind energy projects have been curtailed in 2009 through July. In all, the AESO curtailed wind for 860 hours in 2008, and for 329 hours from January through July of 2009.

Figure 12.

Number of Hours of Wind Curtailment by the Alberta Electric System Operator 2008 and through July 2009



Source: Alberta Electric System Operator, "Weekly Wind Power Operational and Market Reports," http://www.aeso.ca/gridoperations/14246.html.

Spain

Spain has more than 16,700 MW of wind power capacity installed and predicts that it will have more than 20,000 MW by 2010. At times, the highest wind production times occur during times of low or declining periods of electricity demand. On November 24, 2008, at approximately 5:00 AM, wind power contributed more than 46% of the total electricity demand providing 9,250 MW when there was a demand of 21,264 MW.[42] On this date and at other times, the wind power facilities were asked to curtail their operations, limiting output or disconnecting

[42] "La eólica ha alcanzado un nuevo récord de generación con 11.159 MW simultáneos y de producción diaria con 23.060 MWh," press release of the Asociación Empresarial Eólica, January 23, 2009, available at: http://www.aeeolica.es/prensa_notas.php; supplemented with data collected by Red Eléctrica España, Wind Power Generation in Real Time, available at: http://www.ree.es/ingles/operacion/curvas_eolica.asp#.

from the grid altogether. This summary explores some of the operating procedures and tools used to determine when curtailment might be required, as well as a summary of research and analysis used to improve the integration of wind power into the Spanish electric power system.

Grid Operation: Provisions for Renewable Resources

The Red Eléctrica de España (REE), the grid operator in Spain, created the Control Centre for Renewable Energies (CECRE) as the central point for coordination of the interconnected renewable energy resources greater than 10 MW into the operations of the Electrical Control Centre (CECOEL), the Spanish system operator. Put into service in 2006, the objective of CECRE is to achieve a high level of integration for renewable energy sources without compromising system security. In order to achieve this objective, CECRE groups renewable energy facilities by General Coordination Centers (GCCs) to coordinate, control, and supervise all generation units as necessary via supervisory control and data acquisition (SCADA) systems. Every wind power facility of 10 MW or greater must be directly connected to a GCC which must then have sufficient local controls to execute CECRE orders within 15 minutes. The real-time data transferred by wind farms to the GCC and on to the CECRE includes the following:

- Active power,
- Reactive power,
- Connectivity (connected/disconnected),
- Voltage level,
- Wind speed and direction (if available), and
- Ambient temperature (if available).[43]

With this information, CECRE is able to estimate the maximum output of the wind farm and is also able to monitor the stability of the electricity network with regards to wind power production. The information is transmitted every 12 seconds to CECRE and is fed into simulation models to determine the need, if any, for curtailment of wind power facilities.

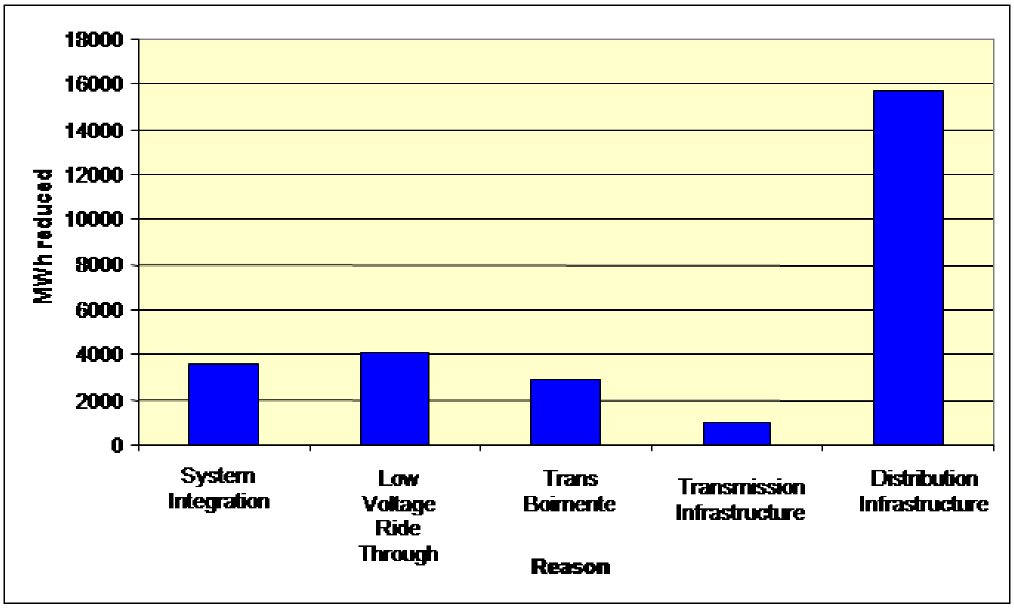
CECRE operates a computer model called GEMAS, (Generación Eólica Máxima Admisible en el Sistema -- Maximum Admissible Wind Power Generation in the System). GEMAS uses switching studies to simulate the likelihood of faults under various real-time situations. Switching over-voltage might occur with abrupt changes in load or supply on a transmission line or as a result of circuit breaker malfunction. The magnitude and shape of the switching over-voltages vary with the system parameters and network configuration, and thus the switching studies are designed to predict and prevent network faults under a variety of conditions. As part of the analysis, the production of every wind farm connected to the GCCs is fed into CECRE's GEMAS model which simulates three-phase solid faults in the bus bars of 70 substations every 20 minutes. Simulation results are continuously compared with real faults

[43] A. Ceña Lázaro and J. Gimeno Sarciada, "The Spanish Experience in the Integration of the Electricity from Wind Power Plants into the Electrical System," 7th *International Workshop on Large Scale Integration of Wind Power and on Transmission Networks for Offshore Wind Farms*, May 2008.

and have been found to be consistent in predicting system faults in a majority of instances.[44] GEMAS is an analytical model that is used to predict the likelihood of faults from real-time wind predictions and thus, is used to indicate a need for curtailment providing specific generation set points, or reduction amounts, based on the real-time data input to GEMAS. For 2007, 23.9 GWh of wind generation was curtailed, representing 0.09% of total wind production.[45] In 2008, the majority of curtailments were due to problems of grid overloads on distribution networks, legally defined in Spain as power lines rated less than 220 kV, as depicted in Figure 13 below:

Figure 13.

Reasons for Wind Production Curtailments in Spain in 2008



Source: Alberto Ceña, "The Impact of Wind Energy on the Electricity Price and on the Balancing Powers Costs: the Spanish Case," presentation before the European Wind Energy Conference, March 19, 2009.

Recent Events

According to the Association Empresarial Eolica (AEE), there were eight notable wind curtailment incidents in 2008. The most significant was an incident on November 1 when a large number of wind power facilities were disconnected from the electric grid on a weekend morning as hurricane force winds came ashore on the north-eastern seaboard. At approximately 7:00 AM, REE ordered the shutdown of 2,700 MW of wind capacity after which power production increased from 1,868 MW to 7,517 MW over an eight-hour period, starting shortly before

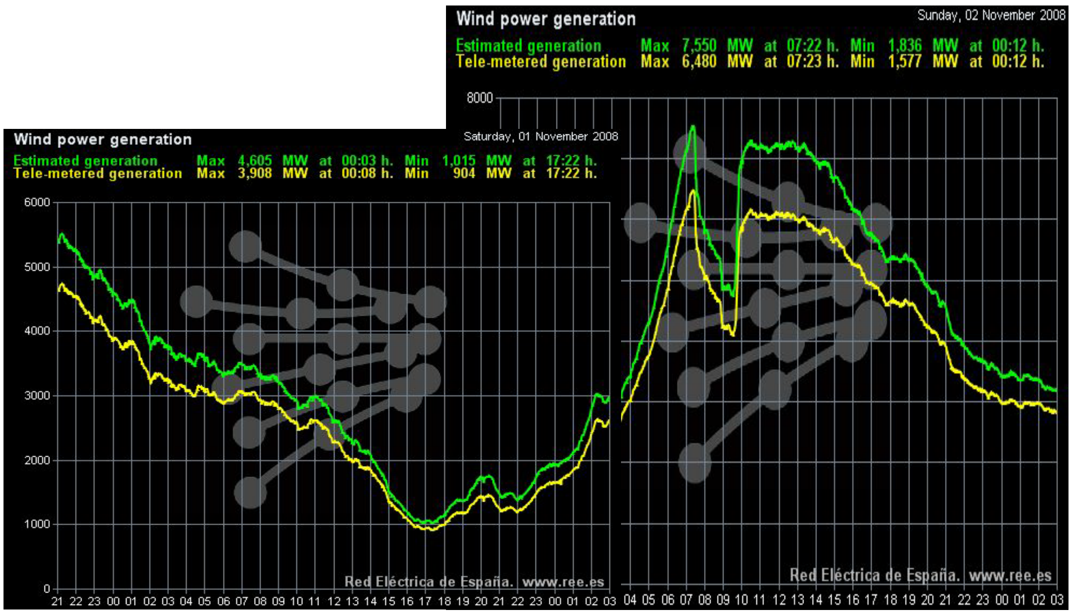
[44] M. de Torre, T. Domínguez, G. Juberías, E. Prieto, O. Alonso, "Operation of a Power System with Large Integration of Renewable Energies," *7th International Workshop on Large Scale Integration of Wind Power and on Transmission Networks for Offshore Wind Farms*, May 2008.

[45] T. Dominguez, M. de la Torre, G. Juberias, E. Prieto, R. Rivas, and E. Ruiz. *Renewable energy supervision and real time production control in Spain,* undated paper, http://www.icrepq.com/icrepq-08/302-dominguez.pdf.

midnight on November 1 (Figure 14). At the time of the ordered curtailment, total demand was approximately 20 GW, with wind capacity serving an estimated 38% of the total load. Demand had been falling throughout the early morning hours. Prior to ordering the curtailment of wind power, REE reduced hydro production to zero and curtailed four combined-cycle gas power facilities by a combined 1,500 MW, dropping the output of the thermal facilities to what is described as the absolute technical minimum output.[46]

Figure 14.

Real-Time Wind Power Generation in Spain for November 1-2, 2008[47]



Source: Red Eléctrica España, Wind Power Generation in Real Time, and Electric Power Demand in Real Time for November 1, 2008, available at: http://www.ree.es/ingles/operacion/curvas_eolica.asp#.

Further analysis of the November curtailment indicates that between 800 and 1200 MW of the curtailed capacity was shutdown erroneously, the miscalculations occurred in part because communication signals that typically provide real-time information (every 12 seconds) on electricity supply and demand were delayed due to satellite communications interference caused by the strong winds. As a result, and consistent with default protocols, CECRE ordered the shutdown of every wind power production facility where GCC was experiencing communication problems. The affected GCCs accounted for more than 800 MW of the wind capacity that was curtailed. This 800 MW of curtailed power was not considered at the time that calculations were made to estimate the need for further shutdown requests. Thus, the calculations determining the need for wind curtailment assumed that the 800 MW − shut down due to communication

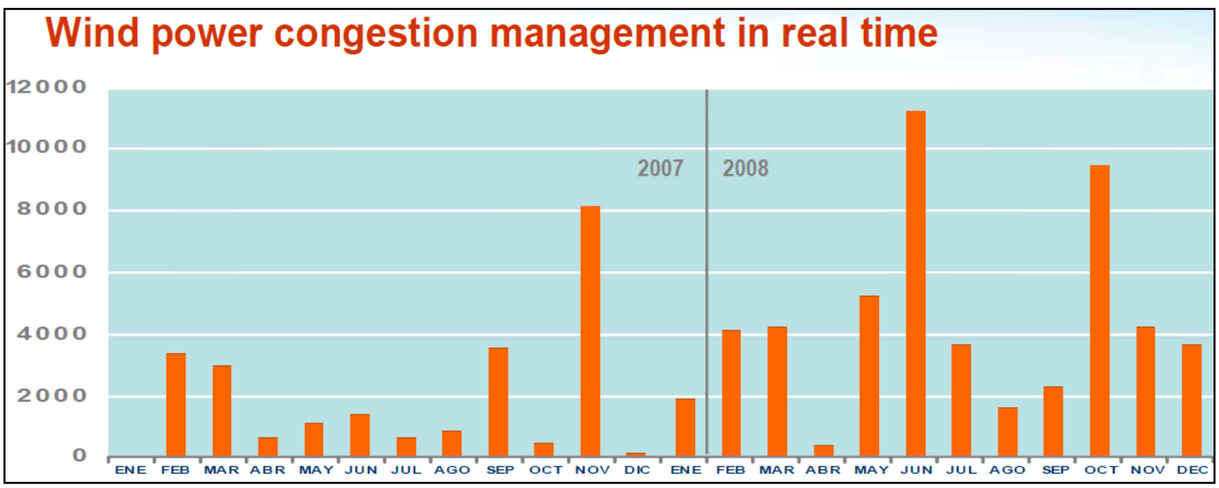
[46] Michael McGovern, "Grid Operator Unplugs Huge Volume of Wind Plant," *Windpower Monthly*, Volume 24, No. 12, December 2008, pp. 27-28.
[47] Data collected by Red Eléctrica España, Wind Power Generation in Real Time, and Electric Power Demand in Real Time for November 1, 2008, available at: http://www.ree.es/ingles/operacion/curvas_eolica.asp#.

problems − were still on line, leading to the call to curtail more wind power than was actually necessary given the actual situation.

Initially, REE curtailed wind output if wind power penetration exceeded 12% of demand. This protocol was the result of a study that was conducted in 2002 and found that the grid functioned adequately at peak with a peak demand of 36,500 and with 10,000 MW of wind, or 27% of demand. According to the study, system problems emerged during minimum demand periods at 25,000 MW, with more than 5,000 MW of wind on line. At peak times, REE believed that as much as 20% could be met by wind, or 13,000 MW, assuming that REE can curtail wind production during periods of minimum demand.[48] REE relaxed this restriction when the wind target was raised to 20 GW and with the adoption of grid management practices. However, the amount of wind power curtailed as part of the congestion management program has increased steadily over the past two years (Figure 15). Lessons learned from the November event, and others, led to closer coordination between AEE and CECRE to improve wind balancing methodologies and practices.[49]

Figure 15.

Capacity of Wind Curtailed by Month in Spain 2007 – 2008



Source: Alberto Ceña, "The Impact of Wind Energy on the Electricity Price and on the Balancing Powers Costs: the Spanish Case," presentation before the European Wind Energy Conference, March 19, 2009.

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[48] Craig, Dr. Lucy, "Large-Scale Integration of Wind Power into Power Systems—the Spanish Experience," presented before the Fifth International Workshop on Large-Scale Integration of Wind Power and Transmission Networks for Offshore Wind Farms, Glasgow, Scotland, April 7-8, 2005.

[49] Michael McGovern, "System Operator Admits Errors," *Windpower Monthly*, Volume 25, No. 5, May 2009, pp. 34-35.

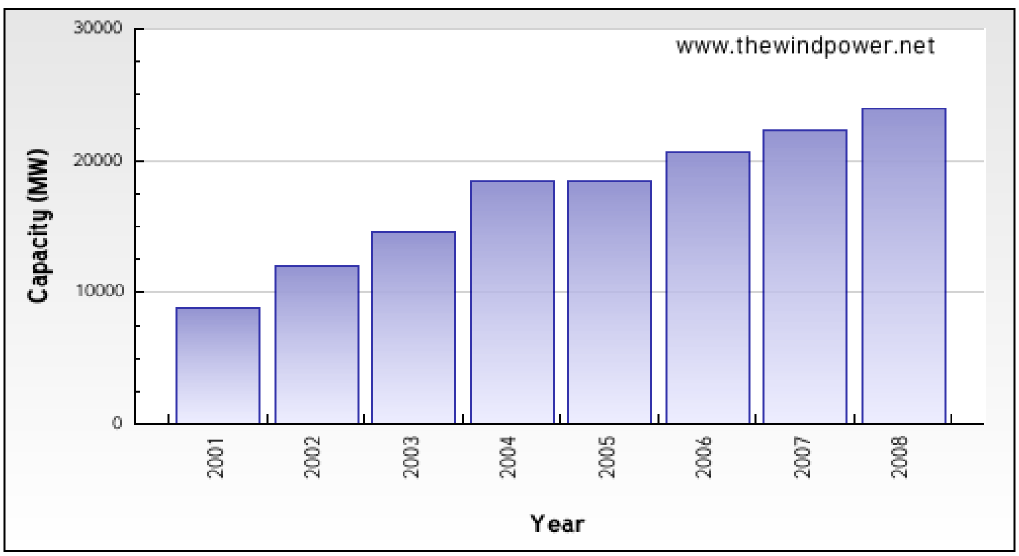
Germany

There are more than 20,000 wind turbines connected to the German electricity grid, with an overall capacity of 23,903 MW as of the end of 2008 (see Figure 16).[50] Lower Saxony is the first German federal state to exceed 6,000 MW of total installed capacity and has a goal of 10,000 MW by 2020.

Large-scale wind power generation has caused some controversy with German utilities, warning that there are bottlenecks in power transmission grids due to the difficulties of integrating high amounts of wind energy. In addition, there are costs for redispatch and grid development to meet the requirements of the Renewable Energy Act. According to RWE, one of the German Transmission System Operators (TSOs) and the grid manager for the German and Northern European System, the balancing power needed for wind power feed-in accounts for almost one fifth of the grid costs.[51] At times, it appeared as though the German TSOs were unable or unwilling to take all of the wind power produced due to transmission congestion. German wind operators complain of the use of 'curtailment' (shutting down of wind power stations) in the effort to alleviate transmission constraints. According to the German environment ministry, 74 GWh of wind power were curtailed between 2004 and 2006, and wind companies had lost revenues of €17,600/MW in 2006 alone.[52]

Figure 16.

Installed Wind Capacity in Germany



Source: Windpower Wind Turbines and Windfarms Database, http://www.thewindpower.net/country-datasheet-2-germany.php.

[50] Windpower Wind Turbines and Windfarms Database, http://www.thewindpower.net/country-datasheet-2-germany.php.
[51] RWE Webpage, company portrait, available: http://www.rwetransportnetzstrom.com/web/cms/en/132902/company/portrait/.
[52] Sara Knight, "Owners Compensated for Lost Production," *Windpower Monthly,* September 2009, p. 84.

German policy is to continue to encourage the development of renewable resources. Passed in 2004, the Renewable Energy Sources Act (EEG) was amended in 2009 that, among other things, allowed voluntary bilateral agreements between a transmission operator and a wind company. These agreements allowed wind companies to interconnect new wind projects if they agree to follow curtailment orders without compensation, thus allowing for the connection of wind projects on the grid that may not have occurred otherwise. E.On Netz alone estimates that these voluntary agreements allowed for more than 1,000 MW of wind capacity to be connected in its service area alone since June 2003.[53]

To further facilitate the development of renewable energy resources, the EEG was amended in June 2008 and entered into force on January 1, 2009. The revised act includes several provisions that are aimed at reducing the amount of curtailment occurring by grid operators faced with congestion and an oversupply of wind power during periods of low demand. Furthermore, cooperation among transmission system operators in Germany and surrounding countries will better facilitate the integration of wind power facilities. Transmission System Operators in Austria, Switzerland, Germany, the Netherlands, Poland, and the Czech Republic launched the regional “TSO System Security Cooperation” in December 2008, with the objective of achieving a common platform for data exchange and grid security. Under this regional initiative, the German TSOs began sharing wind forecasts and near-to-real time data of wind generation to their partners of the TSO Security Cooperation (TSC). This allows TSOs of Austria, Czech Republic, The Netherlands, Poland, and Switzerland to have instantly a better and broader view of the interconnected electricity system in order to better take care of their respective responsibilities and will likely reduce unexpected cross-border flows of electricity during periods of high wind output.

Regulations

There are four German TSOs: Transpower Stromübertragungs GmbH (Transpower), RWE Transportnetz Strom GmbH, Vattenfall Europe Transmission AG, and EnBW Transportnetze AG. In compliance with the German EEG, each of the transmission operators is obligated to take all electricity generated from renewable energy sources within their control area and compensate the generators for their electricity at an established tariff rate. Amendments to the Renewable Energy Act modified the payment provisions of feed-in tariffs, effective January 2009. In 2009, the initial tariff paid for onshore wind-powered installations is generally set at 9.2 euro cents, depending on the quality of the site, and is to be paid for the first five years of operation. The final tariff, paid beginning of year 6 and through year 20, is set at 5.02 euro cents. Both the initial tariff and the final tariff decrease each year by one percent. In the case of offshore wind power facilities, the initial tariff is set at 13 euro cents for the first 12 years of operation. There is also a bonus of 2 euro cents per kilowatt hour generated for offshore facilities commissioned prior to January 1, 2016. Depending on the location of the facility, the initial tariff and bonus tariff might be extended beyond the 12-year time period. The further the facility is located offshore and the deeper the water, the longer the bonus and initial tariff would be extended. The final tariff, paid after the termination of the initial tariff and through year 20 of operation, is set at 3.5 euro cents. The offshore feed-in tariff decreases by 5% each year with the first degression taking place in 2015.

[53] *Ibid.* p. 52.

The amount of renewable energy produced and put onto the German grid is pooled in a common electricity market and balanced among the four German TSOs. Therefore, the cost of purchasing the renewable energy is shared equally by the four TSOs even though two of the TSOs (Vattenfall and Transpower) have substantially more wind power facilities connected to the grid. The balancing of the renewable energy takes place within the day-ahead market of the European Energy Exchange (EEX), and the real-time market exchange and is settled accordingly with settlement data and payments reported by each of the TSOs in an annual report.[54]

According to the EEG amendments in 2008, electric power facilities with over 100 kW of power input will be subject to generation management, e.g., forced curtailment of power production, as grid bottlenecks occur. According to the revised regulations, grid operators will need to pay compensation for energy left unused due to grid management and curtailment procedures.[55] In addition, wind turbines installed before 2009 must be retrofitted so generation can be curtailed at a TSO's request. The TSOs may recover curtailment costs from customers, but it must first demonstrate that all possible measures to optimize, improve, and expand network capacity were taken before undertaking curtailment. However, the rate at which facilities are compensated from energy being curtailed is not specified in the law. The German wind association, Bundesverband Windenergie (BWE) negotiated an agreement with Transpower, a subsidiary of E.On Netz, and one of four transmission grid operators in Germany, and plans to pay the electricity tariff rate for 90% of the lost revenues for the duration of the curtailment, a proposal that was accepted by the wind power plant operators. BWE is hopeful it can reach agreement with the other three TSOs.[56]

Transpower

Since the Renewable Energy Act first went into effect in 2000, there has been a major increase in the installed capacity of wind energy plants. However, as described above, network operators are required without prejudice to accept all production of renewable energy facilities. Under the Renewable Energy Act, TSOs must interconnect facilities of 100 kilowatts or more, providing grid extension and upgrades in the affected area of the network that would otherwise be overloaded by the power supplied. Furthermore, as projected in the dena Grid Study, approximately 850 km of new high-voltage transmission lines will be needed in order to reliably interconnect wind power facilities by 2015.[57] Subsequently, Transpower is working on five grid expansion projects with a combined 370 km of high-voltage transmission lines, and two interconnection projects, including a 380-kV line to the port city of Wilhelmshaven designed to interconnect offshore wind power facilities (Table 4).

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[54] "Renewables Management," Vattenfall website, http://www.vattenfall.de/www/trm_en/trm_en/942105renew/942123renew/index.jsp.

[55] Information provided by Niels Ehlers, Technishe Universitat Berlin, Institut für Energietechnik, Berlin, Germany with reference to the German Wind Energy Association, http://www.wind-energie.de/de/themen/windenergie-im-stromnetz/; and Transpower, http://www.transpower.de/pages/tso_de/EEG__KWK-G/Erneuerbare-_Energien-Gesetz/EEG-Anlagen/Einspeisemanagement/index.htm.

[56] Sara Knight, "Owners Compensated for Lost Production," *Windpower Monthly,* September 2009, p. 84.

[57] *Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020 (dena Grid study)*, Deutsche Energie-Agentur, March 2005.

Table 4.

Transpower Projects in the dena Network Study

Altenfeld - Redwitz (Thüringen, Bavaria)	approx. 25 km
Diele - Niederrhein (Lower Saxony)	approx. 50 km
Ganderkesee - St. Hülfe (Lower Saxony)	approx. 60 km
Hamburg/Nord - Dollern (Schleswig-Holstein, Lower Saxony)	approx. 45 km
Wahle - Mecklar (Lower Saxony, Hesse)	approx. 190 km
Power Plant Connections	
Stade – Dollern	approx. 20 km
Wilhelmshaven – Conneforde	approx. 40 km

Source: Transpower web site,
http://www.transpower.de/pages/tso_en/Tasks/Network_development/index.htm.

Furthermore, Transpower established a power production management system that curtails wind power at times when the grid is overloaded. This permits the continued connection of decentralized energy production plants such as wind farms, solar energy plants, and biomass power stations until the necessary network development has been completed in Schleswig-Holstein and Lower Saxony.

While grid management practices, including increased use of wind forecasting tools and market-based capacity auctions, have helped to mitigate some curtailment and related cross-border congestion, there are still instances of curtailment among wind power facilities connected to the E.On Netz distribution system. In the first six months of 2009, there were 15 instances of congestion and curtailment on the E.On Netz distribution system, affecting 1,080 MW of wind capacity. Table 5 provides the duration and location of each major incident, as reported by E.On Netz on their grid management website. The wind curtailments lasted from 27 minutes to 305 minutes. The Dithmarschen and Ostholstein regions of Schleswig-Holstein are home to a significant share of German wind power, including hundreds of smaller installations interconnected at the distribution level, as well as some of the larger coastal and offshore systems recently installed and interconnected to the Transpower transmission system.

Table 5.

Instances of Wind Power Curtailment on the E.On Netz Distribution System January – June 2009

Date	Duration (minutes)	Region	Maximum Reduction
January 20	82	Nordfriesland, Schleswig-Holstein	60%
March 17	305	Dithmarschen, Schleswig-Holstein	30%
March 17	164	Ostholstein, Schleswig-Holstein	60%
March 22	131	Lower Saxony	60%
March 22	136	Dithmarschen, Schleswig-Holstein	60%
March 23	164	Ostholstein, Schleswig-Holstein	60%
March 24	62	Ostholstein, Schleswig-Holstein	60%
May 6	247	Ostholstein, Schleswig-Holstein	60%
May 18	27	Nordfriesland, Schleswig-Holstein	60%
May 27	95	Nordfriesland, Schleswig-Holstein	30%
May 28	27	Ostholstein, Schleswig-Holstein	60%
June 12	159	Nordfriesland, Schleswig-Holstein	60%
June 26	199	Ostholstein, Schleswig-Holstein	60%
June 26	180	Dithmarschen, Schleswig-Holstein	60%

Source: E.On Netz Einspeisemanagement Einsätze, available at: http://www.eon-netz.com/pages/ehn_de/EEG__KWK-G/Erneuerbare-_Energien-Gesetz/Einspeisemanagement/Einspeisemanagement_Einsaetze/index.htm#tabelle.

Vattenfall

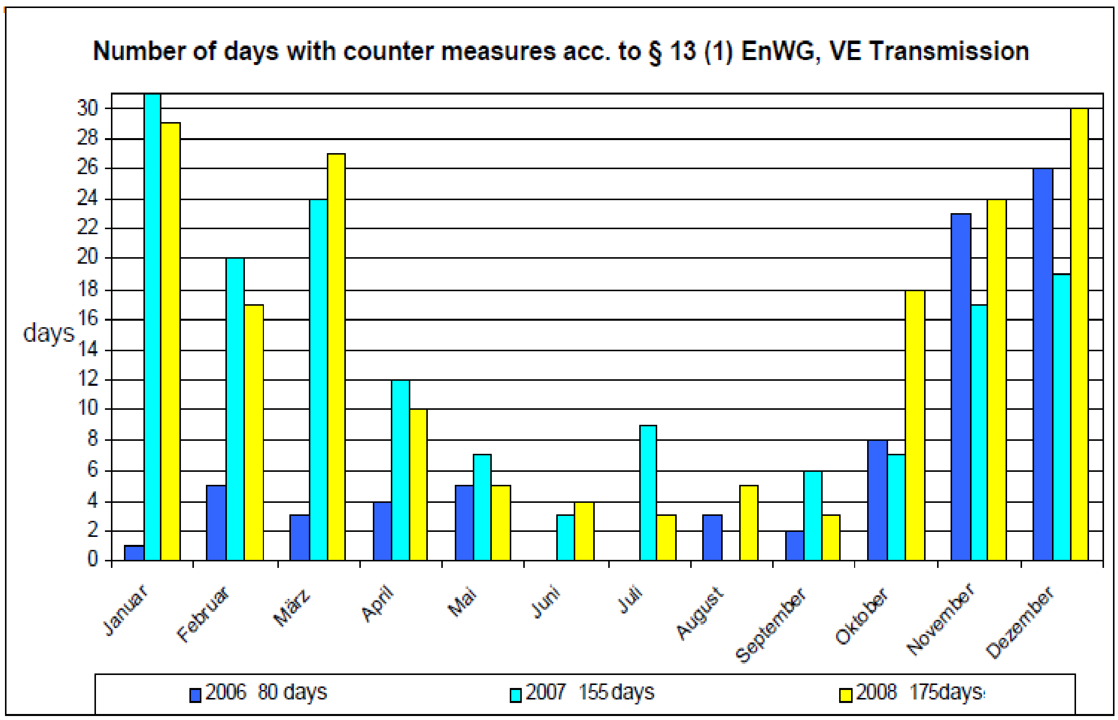
As required by regulation, Vattenfall Europe Transmission guarantees that all energy fed into its control area shall be fully accepted and transmitted in accordance with the German Federal Act on Granting Priority to Renewable Energy Sources (EEG). However, the number of days in which congestion occurs on Vattenfall transmission lines has increased over the past three years. In 2008, there were 175 days in which grid congestion occurred, a 13% increase over 2007 during which congestion was present for 155 days (Figure 17). In its annual report to the

German grid regulator, Vattenfall Europe specifically cited wind power as a contributing factor to the transmission bottlenecks which created critical situations on the grid.[58]

Vattenfall currently has approximately 425 km of new transmission projects in various stages of development. The grid extension is specifically designed to help transmit wind power located in remote areas to regions with greater electricity demand (Figure 18).

Figure 17.

Number of Days with Grid Congestion in Vattenfall Transmission System

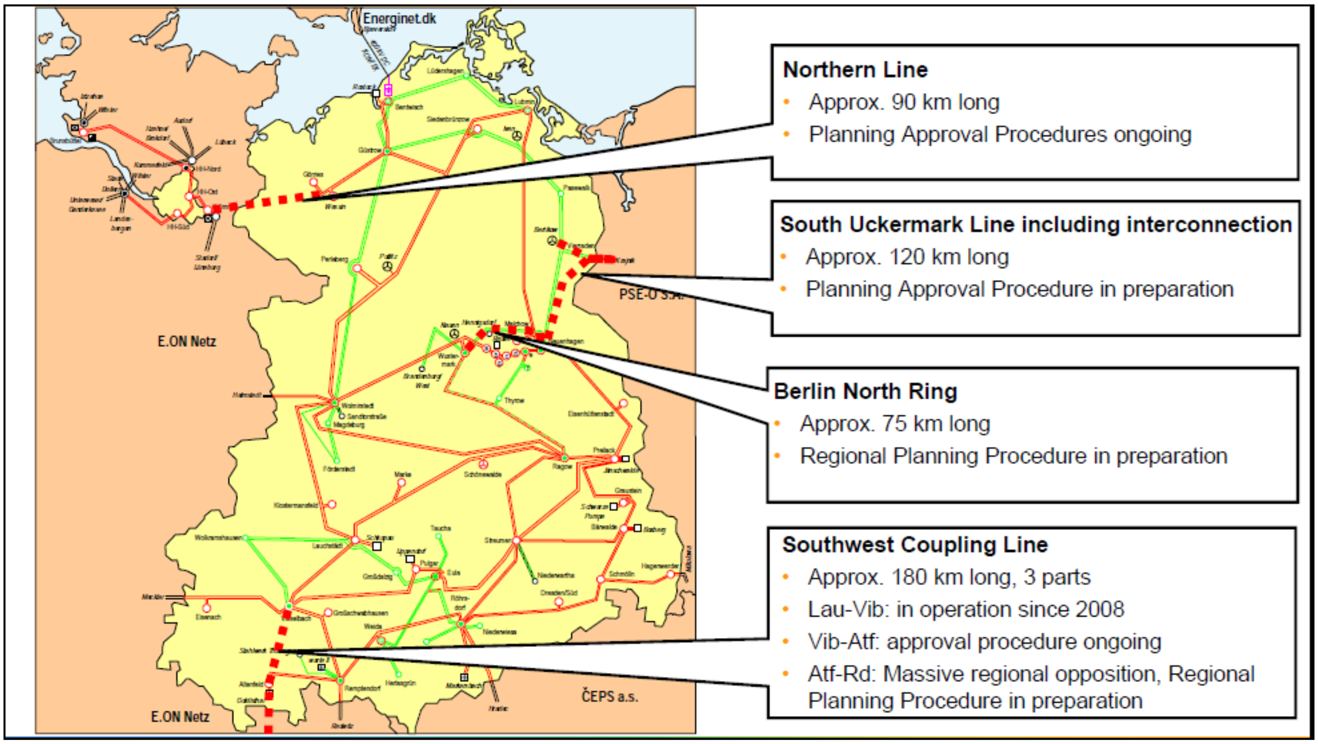


Source: Dirk Bierman, Vattenfall Europe Transmission GmbH, *Incentive Regulation for German TSOs – A Major Challenge in a Changing Environment*, 4th Conference on Energy Economics and Technology, Dresden, 2009.

[58] Frederik Richter, *German Utilities Warn of Power Bottlenecks Due to Wind Integration,* Thomson Financial, January 31, 2008.

Figure 18.

Vattenfall Grid Extension



Source: Dirk Bierman, Vattenfall Europe Transmission GmbH, Incentive *Regulation for German TSOs - A Major Challenge in a Changing Environment*, 4th Conference on Energy Economics and Technology, Dresden, 2009.

In addition to balancing overall electricity supply and demand in cooperation with neighboring TSOs, Vattenfall requires that "renewable energy substitutes" be available to help smooth fluctuations in energy supply, in particular from wind power. These "renewable energy substitutes" are pre-qualified energy resources that are able to provide positive and/or negative primary, secondary, and "minute" reserves. Pre-qualified resources bid into a regional market and are dispatched according to economic efficiency as needed to provide "renewable compensation energy." Table 6 provides data pertaining to wind power in the control area of Vattenfall, demonstrating the positive and negative increases in wind power production that would require the use of renewable energy substitutes.[59]

[59]Vattenfall, "Wind Power," http://www.vattenfall.de/www/trm_en/trm_en/941994gridx/942069windx/index.jsp.

Table 6.

Control Area of Vattenfall Europe Transmission: Wind Power Specifications for 2007 on the Basis of Information from Distribution System Operators (actual values)

Average installed capacity of wind power plants	8,573 MW
"Secured" capacity (power credit acc. to dena) (4–5% of installed capacity of wind power plants)	420 MW
Maximum wind power in-feed	7,511 MW
Minimum wind power in-feed	2 MW
Largest quarter-hourly jump in wind power	+638 MW / –977 MW
Largest hourly jump in wind power	+1,601 MW / –1,618 MW
Largest daily jump caused by wind power	+6,146 MW / –6,398 MW
Energy-based supply ratio	21.88%
Installed capacity of wind power plants at the end of 2007	8.970 MW

Source: Vattenfall, "Wind Power,"
http://www.vattenfall.de/www/trm_en/trm_en/941994gridx/942069windx/index.jsp.

RWE

As the "control block" coordinator, RWE coordinates the load and frequency control for the four German TSO areas. RWE is also responsible for the coordination, energy exchange, and system accounting both for not only the German transmission grid, but the entirety of the northern part of the European interconnected system (Belgium, Bulgaria, Germany, The Netherlands, Austria, Poland, Romania, Slovakia, Czech Republic, and Hungary). The German-Dutch security center, which was established in concept in July 2008, went into operation in January 2009. The center will locate bottlenecks in the grid and support the system operation activities. The center is considered to be an important new tool that will enhance the security of the system and allow for better management of the fluctuations in the electricity flows on the grid that come from large amounts of wind power.[60]

[60] RWE, "First European Security Center Taken into Action," RWE Press Release issued January 5, 2009, http://www.rwetransportnetzstrom.com/web/cms/en/133208/press-releases/.

IV. Summary

Wind curtailment initiatives appear to be increasing, perhaps in part because of the rapid growth of wind power, and the lack of development of supporting transmission infrastructure to keep up. To date, with the exception of isolated systems such as Hawaii, it appears that wind curtailment occurs for two primary reasons: 1) lack of available transmission during a particular time to incorporate some or all of the wind generation; or 2) high wind generation at times of minimum or low load, as wind generation in some regions may have production characteristics nearly opposite of electricity demand, and the energy cannot be exported to other balancing areas because of lack of transmission. As wind penetration levels in most balancing areas in the United States are still quite low, the primary cause of most wind curtailments can be attributed to a lack of transmission capacity.

A wide variety of approaches are being taken with wind curtailment, perhaps not only reflective of the early stage of wind curtailment initiatives, but also representative of regional markets that may not be transferrable to other regions. Some regions with LMP tend to allow market price signals to drive the need for curtailment by wind power and conventional facilities, only taking prescriptive action when market forces are inadequate, or during emergency events. For example, PJM and the NYISO are incorporating wind into their economic dispatch systems, and are requiring wind generators to submit economic price curves to determine at what price a wind generator will be willing to be curtailed. Both also allow generators to submit negative LMP bids.

Conversely, BPA does not have LMP; instead BPA ties its wind curtailment to the amount of available reserves. BPA may require wind generators to curtail after 90% of BPA's reserves have been deployed. BPA assigns maximum generation limits based on their scheduled output, plus a proportional allocation of balancing reserves. When BPA is using 90% of its reserves, it will require variable generators that have over-scheduled to reduce generation to a specified level, while variable generators that have under-generated will have schedules curtailed to actual levels, plus the allocated amount of reserve. Others, such as Southern California Edison and Xcel Energy's subsidiaries that are not in the Midwest ISO, have contractual provisions that allow each utility to call upon wind curtailment under certain conditions. Still others have tied curtailment to grid interconnection and set daily capacity limits for wind generation.

Given the early stage of wind curtailment initiatives, it is difficult to point to best practices or to make any generalizations. Nevertheless, some principles can be articulated. First, the grid operator should ensure that all actions have been taken before curtailing generation, such as ensuring that all non-wind generation is running at minimum, that import schedules have been reduced or eliminated, and that opportunities to export power have been maximized. Second, if generation is to be curtailed, all generation should be treated comparably. Wind power should not be the first to be curtailed simply because it is new and unfamiliar, or because wind is extremely quick to respond to instructions from the system operator. Third, to the extent regional markets allow it, generators (including wind) should have the option to bid in a price at which they are willing to be curtailed. Alternatively, allowing the trading of daily capacity limits among wind generators (as was done in ERCOT until recently) is another potential strategy. The question of whether generators (including wind) should be paid if curtailed, and on what basis, should also be addressed.

The amount of wind curtailment in the United States will likely rise in the near future as more wind is added, and the nation tries to work through issues regarding transmission siting and cost allocation. Should significant new transmission be developed in the United States over the next several years, the need for wind curtailment would likely drop as new transmission comes on line. Additional measures that could reduce wind curtailment include large balancing areas, dynamic scheduling, and dynamic ratings of transmission lines.

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