Arnold Schwarzenegger
Governor

REVIEW OF INTERNATIONAL EXPERIENCE INTEGRATING VARIABLE RENEWABLE ENERGY GENERATION

PIER PROJECT REPORT

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit the electricity and natural gas ratepayers in California.

The PIER program strives to conduct the most promising public interest energy research by partnering with RD&D organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural /Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Review of International Experience Integrating Variable Renewable Energy Generation is the final report for a subtask of Task 3 for the PIER Intermittency Analysis Project (IAP), contract number 500-02-004, work authorization number MR-017, conducted by the IAP team comprised of the California Wind Energy Collaborative, Exeter Associates, BEW Engineering, Davis Power Consulting, and GE Energy Consulting (with assistance from AWS Truewind, National Renewable Energy Laboratory (NREL), Oak Ridge National Laboratory (ORNL), and Rumla Consulting). The information from this project contributes to PIER's Renewable Energy Technologies program.

For more information on the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at (916) 654-5164.

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Abstract

This report summarizes the experience in the United States and internationally through 2006 with integrating variable renewable energy generation, primarily wind generation, and discusses potential operating and mitigation strategies for incorporating variable renewable energy generation. Initially, wind development in Europe, particularly in Denmark and Germany, consisted of smaller but numerous wind projects interconnected to the distribution grid, in contrast with larger, utility-scale wind projects interconnected to the transmission grid in the United States. The differences between Europe and the United States are starting to narrow as development of variable renewable energy generation (e.g. wind and solar) increases and as wind development takes place in more countries. In addition, as more utility-scale wind projects emerge, more countries are relying on common strategies, such as grid codes, to help integrate variable renewable energy generation. This report is a part of the Intermittency Analysis Project (IAP), a comprehensive project aimed at assessing the impact of increasing penetration of variable renewable energy generation in California. A review of the international experience will provide perspective and insight to the IAP analysis team on various techniques for managing intermittency.

Keywords: wind integration, solar variability, wind forecasting, variable renewable energy generation, wind forecasting, transmission, VAR support, reserves, ramp rates, grid code, ancillary services.

Executive Summary

Introduction

California's renewable policy targets of 20 percent renewable energy by 2010 and 33 percent by 2020 are likely to be met with significant amounts of variable renewable energy generating resources such as wind and solar power. The anticipated growth in these renewable sources is challenging decision makers to look at how the California grid will accommodate these resources. Some answers are found by examining international experience, where wind development has been growing steadily for several years, and solar generating capacity is accelerating. By the end of 2006, over 74 gigawatts (GW) of wind power capacity has been installed worldwide, with two-thirds of that in Europe. By the end of 2005, about five GW of grid-connected solar power is installed worldwide, with over half of that capacity located in Germany.

Purpose

Although there are numerous studies estimating potential wind integration costs that rely on models and power simulations, there is little information that provides actual experience with increasing levels of variable renewable energy generation. This report will discuss results from both actual experience and studies that rely on models and simulations, and will attempt to distinguish between those two throughout the document. This report is part of the Intermittency Analysis Project (IAP) and is funded by the California Energy Commission's Public Interest Energy Research (PIER) Program. The IAP is a comprehensive analysis project aimed at assessing the impact of increasing penetration of variable renewable energy generation in California. A review of the international experience will provide perspective and insight to the IAP analysis team on various techniques for managing intermittency. The IAP will model four scenarios of increasing levels of variable renewable energy generating resources, and assess the potential grid impacts and propose market and operation strategies to mitigate impacts, if any are identified.

Market Penetration

Worldwide wind capacity is more than 74 GW by the end of 2006, with Europe accounting for two-thirds of that capacity. Germany has the most installed wind capacity with over 20 GW, followed by Spain (11 GW), the United States (11 GW), India (6 GW) and Denmark (3 GW). By energy contribution, Denmark is the world leader, with over 18 percent of its energy coming from wind. Some regions within countries have even greater penetrations of wind power, as indicated in Table ES-1.

Germany accounts for more than half of the world's installed solar capacity, with the United States and Japan the next leading countries. There is less grid experience with solar capacity as there is with wind power, in part because larger grid-connected solar facilities are just now coming on-line. Of the 20 largest solar facilities in the world, only four were installed before 2004. For that reason, this report will mostly focus on wind power.

Table ES-1. Examples of wind power penetration levels, 2005

Country or region	Installed wind capacity (MW)	Total installed power capacity (MW)	Average annual penetration level[a] (%)	Peak penetration level[b] (%)
Western Denmark	3,128	7,488	~23	>100
Germany:	18,428	124,268	~5	n.a.
Schleswig-Holstein	2,275	———[c]	~28	>100
Spain	10,028	69,428	~8	~25%
Island systems:				
Swedish island of Gotland[d]	90	No local generation in normal state	~22	>100

n.a. = Not available

[a]Wind energy production as share of system consumption

[b]Level at high wind production and low energy demand, hence, if peak penetration level is >100% excess energy is exported to other regions.

[c]German coastal province

[d]2002 data. The island of Gotland has a network connection to the Swedish mainland.

Source: Adapted from Soder, Lennart and Ackerman, Thomas (2005). "Wind Power in Power Systems: An Introduction," In T. Ackerman (Ed.), *Wind Power in Power Systems* (pp. 25-51). England: John Wiley and Sons, Ltd. Updated and adapted by the author. Reproduced with permission.

Market Operations

Europe uses different terminology in describing the ancillary services necessary to maintain grid reliability than the United States (Table ES-2). In Europe, primary reserves assist with the short-term, minute-to-minute balancing and control of the power system frequency, and is equivalent in the United States to regulation. Secondary reserves in Europe take over for primary reserves 10 to 30 minutes later, freeing up capacity to be used as primary reserves. Longer-term reserves in Europe are called tertiary reserves and are available in the periods after secondary reserves. Since we are focused on international experience with integrating variable renewable energy generation, we will use the terms primary and secondary reserves for this report.

To date, grid reliability has been maintained as wind and solar capacity has been incorporated. The largest impact of wind appears to be on secondary reserves. Wind has had little effect on primary reserves, as the variations in wind power are random. When aggregated with load and generation variations, the variations from wind power tend to be small or cancel each other out. So far, Denmark, Germany and Spain have not changed the amount of primary reserves required to maintain system reliability, and wind integration studies conducted in Germany and the United Studies have also found that only small amounts of additional regulating reserves are required.

Table ES-2. Reserve definitions in Germany, Ireland and the United States

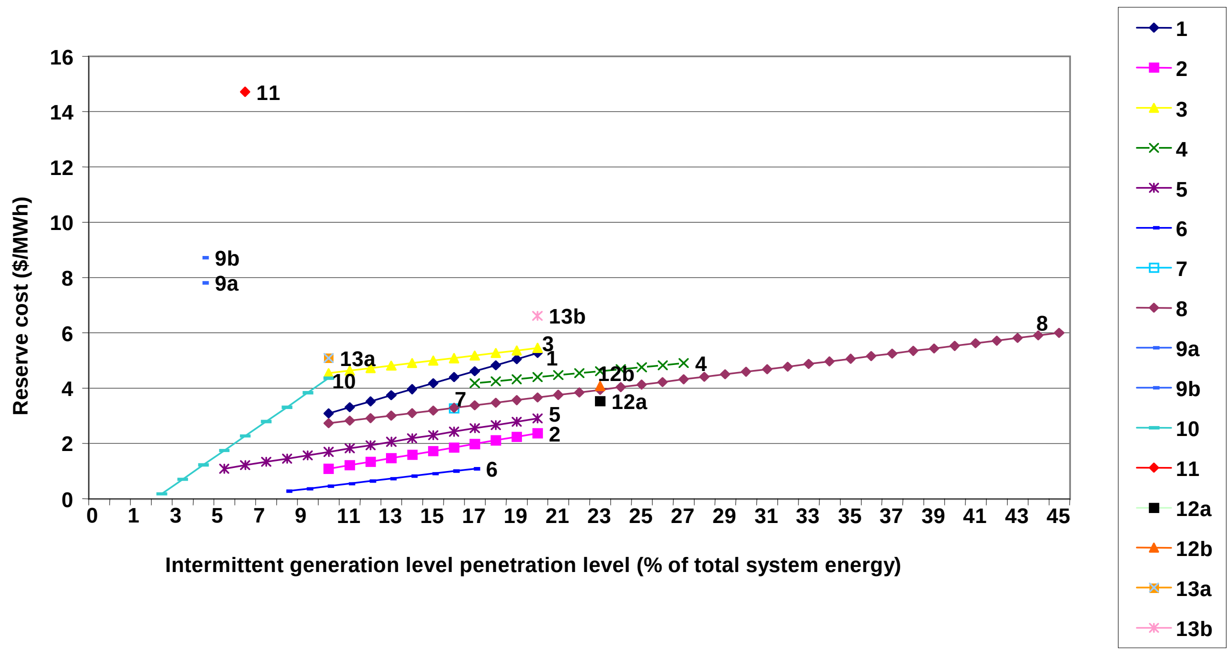
	Short-term reserves	Medium-term Reserves		Long-term reserves
Germany	Primary reserve: available within 30 seconds, released by transmission system operator	Secondary reserve: available within 5 minutes, released by transmission system operator	Minute reserve: available within 15 minutes, called by transmission system operator from supplier	n/a
Ireland	Primary operating reserve: available within 15 seconds (inertial response/ fast response)	Secondary operating reserve: operates over timeframe of 15-90 seconds	Tertiary response: from 90 seconds onwards (dynamic or static reserve)	n/a
United States	Regulation horizon: 1 minute to 1 hour with 1- to 5-second	Load-following horizons: 1 hour within increments 5- to 10 -minute increments (intra-hour) and several hours (inter-hour)		Unit-commitment horizon: 1 day to 1 week with 1-hour time increments

Source: Gul, T. and Stenzel, T. 2005. *Variability of Wind Power and Other Renewables: Management Options and Strategies*. Paris: International Energy Agency

Including both primary and secondary reserve costs, it appears that the cost of integrating wind is less than $6/MWh at energy penetration levels of up to 20 percent (Figure ES-1). Caution should be used in interpreting Figure ES-1, as the studies employ different methodologies, data, time scales, and tools. For example, the E. On Netz data in Figure ES-1 measures reserve impacts of wind on a day-ahead basis, while other studies measure reserve impacts during the hour; the results illustrate that wind cannot be forecasted as accurately on a day-ahead basis as one-to-two hours ahead.

Factors that affect wind integration costs include:

- How the variability in wind generation interacts with the variability in electricity demand
- The geographic concentration of wind projects
- How far in advance the power schedules must be submitted to system operators.



	Country	Comments	Reference
1	UK	Lower bound estimates based on analysis from NEMCO (Australia), Lewis Dale of National Grid, SCAR Study and Millsborrow 2002	Mott MacDonald, 2003.
2	Nordic	Based on data collected in Finland, Sweden, Norway and Denmark	Holttinen, 2004.
3	UK	Dale, Milborrow SCAR, PIU studies	Dale et al 2003.
4	UK	Based on modeling efforts	Ilex & Strbac, 2002.
5	Ireland	Numbers derived from analysis of international experience, specifically, Denmark, US (BPA)	Millborrow, 2004.
6	Ireland	Study conducted for Sustainable Energy Ireland, estimates based on modeling analysis	Ilex et al, 2004.
7	Denmark	Actual costs to Eltra, Danish grid operator	Pedersen et al, 2002
8	UK	Estimates based on the technical standards of the National Grid Company	Milborrow, 2001a
9a	Spain	Low market costs of procuring the difference between predicted and actual generation	Fabbri et al, 2005.
9b	Spain	High market costs of procuring the difference between predicted and actual generation	Fabbri et al, 2005.
10	UK	Estimates based on 2001 market data for imbalances	Dale, 2002
11	Germany	Figures derived from analysis of E.On Netz study	Milborrow, 2005a
12a	Denmark	Low estimate based on Nord Pool balancing market (2002 prices	Ackerman et al, 2005
12b	Denmark	High estimate based on Nord Pool balancing market (2002 prices)	Ackerman et al, 2005
13a	Scotland	National Grid estimates for balancing costs with 10 % penetration of wind in the UK, as reported to the Scottish Parliament	National Grid Transco, 2004
13b	Scotland	National Grid estimates for balancing costs with 20 % penetration of wind in the UK, as reported to the Scottish Parliament	National Grid Transco, 2004

Figure ES-1. Range of findings of additional reserve costs from wind generators

Source: Adapted from Gross, Robert; Heptonstall, Philip; Anderson, Dennis; Green, Tim; Leach, Matthew; and Skea, Jim. (2006). *The Costs and Impacts of Intermittency*. London: United Kingdom Energy Research Center. Available at http://www.ukerc.ac.uk/content/view/258/852. British currency converted to U.S. $ using a conversion of $1.8717 per British pound, as of May 25, 2006. Denmark 2002 from Ackerman, Thomas; Morthorst, Poul Erik. 2005. "Economic Aspects of Wind Power in Power Systems." In T. Ackerman (Ed.), *Wind Power in Power* Systems (pp. 384-410). England: John Wiley and Sons, Ltd. National Grid numbers from National Grid Transco. 2004. *Submission to the Enterprise and Culture Committee: Renewable Energy in Scotland Inquiry*. Available at www.scottish.parliament.uk.. Sustainable Energy numbers from Sustainable Energy Ireland. 2004. *Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System*. Available at http://www.sei.ie/uploadedfiles/InfoCentre/IlexWindReserrev2FSFinal.pdf. See Reference for details.

Submitting schedules closer to the real-time market will allow for more accurate predictions of wind generation, although some trade-offs are involved. Having a shorter period of time before the start of real-time market operations may lead to a need for more flexible operating reserves, or perhaps higher costs from the increased starting and stopping of conventional units. The shorter periods of time may not allow sufficient time to change unit commitment decisions for conventional generating units. This problem can be simply addressed with a wind plant schedule update.

Figure ES-2 illustrates the estimated percentage increase in reserves from wind from several wind integration studies in Europe. The methodology differs significantly by study, making these results not directly comparable. For example, the dena study in Germany estimated reserve requirements on a day-ahead basis, while the United Kingdom and Sweden studies estimated reserve requirements four hours ahead. The other studies estimated the impact on reserves from wind variability during the operating hour. Generally, Figure ES-2 suggests that an increase in reserves is likely with higher levels of wind penetration.

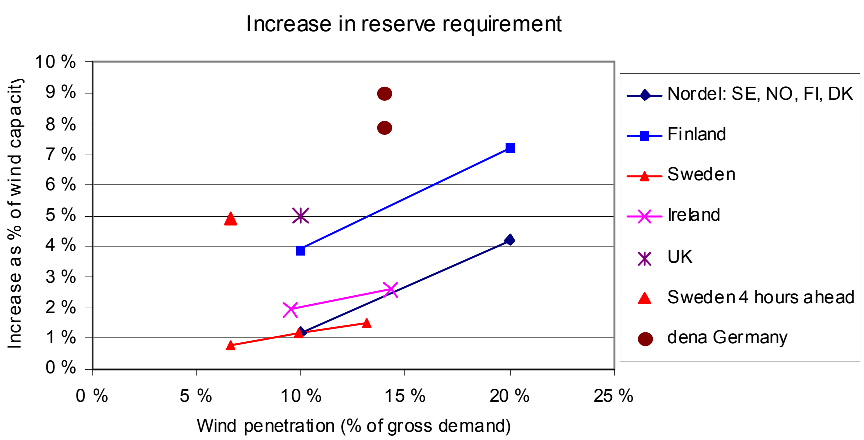


Figure ES-2. Estimated increase in reserve requirements from wind from various studies in Europe

Source: Holttinen, Hannele, Pete Meibom, Antje Orths, Frans Van Hulle, Cornel Ensslin, Lutz Hofmann, John McCann, Jan Pierik, John Olav Tande, Ana Estanqueiro, Lennart Soder, Goran Strbac, Brian Parsons, J. Charles Smith and Bettina Lemstrom. *Design and Operation of Power Systems with Large Amounts of Wind Power: First Results of International Energy Agency Collaboration*. Global Wind Power Conference, Adelaide, Australia. September 18-21, 2006. http://www.ieawind.org/AnnexXXV/Meetings/Oklahoma/IEA%20SysOp%20GWPC2006%20 paper_final.pdf. (accessed November 8, 2006).

Wind integration studies conducted in the United States have often focused on unit commitment, the time frame where generators are committed in advance to meet expected demand (Table ES-3). This is where improvements in wind forecasting are likely to have the greatest impact. In general, the European studies did not focus as much on unit commitment issues.

Table ES-3: Estimated ancillary service costs from various wind integration studies in the United States

Study	Wind Penetration (%)	Regulation $/MWh	Load Following $/MWh	Unit Commitment $/MWh	Gas Supply Cost ($/MWh)	Total $/MWh
UWIG/Xcel	3.5	0	0.41	1.44	NA	1.85
PacifiCorp	20	0	1.64	3.00	NA	4.64
BPA/Hirst	7	0.19	0.28	1.00-1.80	NA	1.47-2.27
PJM/Hirst	0.06-0.12	0.05-0.30	0.70-2.80	N/A	NA	0.75-3.10
We Energies I	4	1.12	0.09	0.69	NA	1.90
We Energies II	29	1.02	0.15	1.75	NA	2.92
Great River Energy I	4.3	NA	NA	NA	NA	3.19
Great River Energy II	16.6	NA	NA	NA	NA	4.53
CA RPS Phase III	4	0.46	NA	NA	NA	NA
MN DOC/Xcel	15	0.23	0	4.37	NA	4.60
Xcel-PSCo	10	0.20	NA	3.32	1.26	3.72
Xcel-PSCo	15	0.20	NA	3.32	1.45	4.97

Sources: Parsons, Brian, et al: *Grid Impacts on Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*. Paper given to Nordic Wind Power Conference, May 22-23, 2006, Finland; and Smith, J.C.; DeMeo, E.; Parsons, B.; and Milligan, M. *Wind Power Impacts on Electric-Power-System Operating Costs: Summary and Perspective on Work to Date*. March 2004. Presented to the American Wind Energy Conference, Chicago, Illinois. www.nrel.gov/docs/fy04osti/35946.pdf. (accessed June 2, 2006).

Although present operating practices in Europe have successfully integrated wind power, current initiatives indicate that changes may be necessary as more wind power comes on-line. Among other initiatives:

- The European Transmission System Operators (TSO), the association of transmission system operators in Europe, is conducting a Europe-wide wind integration study, with results due by 2008.
- The International Energy Agency (IEA) is sponsoring an annex, "Design and Operation of Power Systems with Large Amounts of Wind Power Production," that began in mid-2006.

In Asia, the situation is different in China and India, as the lack of grid infrastructure severely handicaps not only wind development and operations but also the economy as a whole in both countries.

Capacity Credit of Wind

A review of various studies estimating the capacity credit of wind power in Europe indicated that wind has a capacity credit greater than zero, and also that the capacity credit decreases as the level of wind generation rises. These findings are illustrated in Figure ES-3. Capacity credit studies for wind in the United States have not generally measured the capacity credit of wind versus the market penetration of wind. Instead, these studies have focused more on the methods and mechanics of determining the capacity credit for wind. A variety of approaches have been used in the United States for determining the capacity credit of wind, ranging from determining the equivalent load-carrying capability of wind; using a proxy value; applying the capacity factor of wind during peak demand hours; and using the capacity value of wind during a fraction of the top peak demand hours (Table ES-4).

As with Figure ES-1, caution should be used in interpreting Figure ES-3 and Table ES-4, as different study methodologies, assumptions and data were used in several of these studies.

Operating Issues to Date

Minimum Load: Defined simply, minimum load is the smallest amount of load on the grid during a defined period of time. Wind production may coincide with times of minimum load and add to system challenges in managing the grid.

Wind integration in Denmark and Germany has been eased considerably by the extensive interconnections the two countries have with neighboring countries. At times in Denmark, hourly wind production can exceed load demand, and conventional power plants have to reduce their production until the supply and demand balance is restored. On these occasions, spot prices may drop to zero, as occurred for 83 hours in Denmark in 2003. General Electric's wind integration study for the New York State Energy Research and Development Authority (NYSERDA) found that minimum load is not a significant issue with 10 percent wind penetration, as New York is an energy importer without wind and remains an importer with wind.

California has the potential for minimum load issues. These issues include:

- "Must-run" qualifying facility contracts under the Public Utility Regulatory Policies Act.
- Increased procurement of combined cycle natural gas projects that operate baseload and around the clock.[1]

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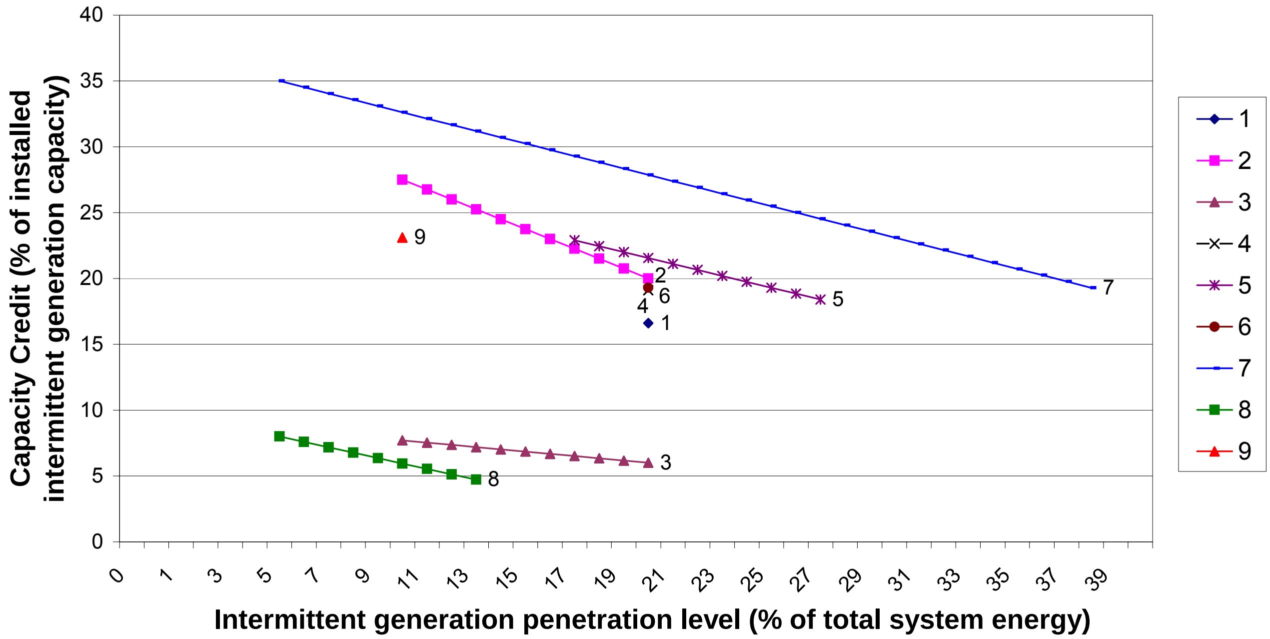
1 Another potential near-term contributor to minimum load issues is the around-the-clock energy procurement contracts that the California Department of Water Resources signed during the electricity crisis of 2000 and 2001. However, these contracts expire between 2009 and 2011, likely before variable renewables may reach high levels of market penetration in California.



	Country	Comments	Reference
1	Ireland	Estimate of capacity credit values for an island system	Watson 2001
2	UK	Estimates based on analysis from a three different sources, Central Electricity Generating Board, National Grid, and System Costs of Additional Renewables (SCAR Report)	Mott MacDonald 2003
3	Germany	Dena project steering group	Dena 2005
4	UK	Examines the CEGB and SCAR reports and adjusts them for greater penetrations of wind	Dale, et al., 2003
5	UK	Based on modeling	Ilex and Strbac, 2002
6	N. Europe	Estimates based on reanalysis data collected from operating wind facilities	Giebel, 2000
7	UK	Early assessment of capacity of wind projects in the UK	Grubb 1991
8	Germany	E. On Netz	E. On Netz 2005
9	UK	Study Commissioned by UK Government	Sinden 2005

Figure ES-3. Capacity credit values

Source: Adapted from Gross, Robert; Heptonstall, Philip; Anderson, Dennis; Green, Tim; Leach, Matthew; and Skea, Jim. (2006). *The Costs and Impacts of Intermittency*. London: United Kingdom Energy Research Center. Available at http://www.ukerc.ac.uk/content/view/258/852. See Reference for details.

The California Independent System Operator (CAISO) noted that minimum load conditions can be exacerbated in April and May when hydroelectricity generation, considered "must-take," increases because of snow melt and when wind generation correspondingly is at a high level as well.

Table ES-4. Examples of wind capacity credit methods in the United States

Region/Utility	Method	Note
CA/CEC	ELCC	Rank bid evaluations for RPS (low 20s)
PJM	Peak Period	Jun-Aug from 3 p.m.-7 p.m., capacity factor using 3-year rolling average (20%, fold in actual data when available)
ERCOT	10%	May change to capacity factor, 4 p.m.-6 p.m., Jul (2.8%)
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26-34%)
GE/NYSERDA	ELCC	Offshore/onshore (40%/10%)
CO PUC/Xcel	ELCC	PUC decision (30%) and Current Enernex study possible follow-on, Xcel using MAPP approach (10%) in internal work
RMATS	Rule of thumb	20% all sites in RMATS
PacifiCorp	ELCC	Sequential Monte Carlo (20%)
MAPP	Peak Period	Monthly 4-hour window, median
PGE		33% (method not stated)
Idaho Power	Peak Period	4 p.m.-8 p.m. capacity factor during July (5%)
PSE and Avista	Peak Period	PSE will revisit the issue (lesser of 20% or 2/3 Jan C.F.)
SPP	Peak Period	Top 10% loads/month; 85th percentile

Source: Milligan, Michael, and Kevin Porter (2005). *Determining the Capacity Value of Wind: A Survey of Methods and Implementation*. Golden, CO: National Renewable Energy Laboratory. Available at www.nrel.gov/docs/fy05osti/38062.pdf.

Ramping: At times, wind generation can ramp up and down quickly, particularly in response to storms. In general, ramping events are of more concern to smaller, weaker grids with few external interconnections and grids with large concentrations of wind projects in one region. Grids with these features typically do not have a "deep" stack of generating resources, connections to other regions or the large geographic diversity of wind resources to manage ramping events. For this reason, the TSOs that have proposed or implemented ramping limits on wind turbines have tended to be smaller grids or grids with few external interconnections. One exception is in Germany, where the TSOs limit the positive ramp rate of wind generation to 10 percent of rated power per minute. Some examples include the following:

- EirGrid in Ireland limits the positive ramp rate to 1–30 MW per minute
- Scotland, where the positive ramp rate is limited to 1–10 MW per minute, depending on the capacity of the wind project, and the downward ramp rate to 3.3 percent of power output per minute
- The Alberta Electric System Operator has proposed limiting system-wide ramp rates for wind projects to 4 MW per minute.

The IAP will assess the ramping impacts of variable resources on the California grid. As a state, California has a relatively deep resource stack and interconnections with the Pacific Northwest and the Southwest. California is not in the extreme situation as islands or smaller grids. In 2006 the California Wind Energy Collaborative (CWEC), under a consulting agreement to the Energy Commission, examined ramping capability in the CAISO based on publicly available data. CWEC determined that the CAISO had sufficient ramping capability to accommodate load variability and current levels of variable renewable energy generation.

Transmission Rating and Unscheduled Generation: At times, the combination of wind from Denmark and Germany can result in unscheduled power flows on the European transmission grid, especially during times of high wind production and low demand. The lack of sufficient north-to-south transmission in Germany results in wind generation from Northern Germany being transmitted to customers in Southern Germany via the transmission networks of the Netherlands, Belgium and France.

In 2005 the Electric Power Group (EPG), under consulting agreement to the Energy Commission, suggested that the frequency response of generating resources in California and throughout the Western Electricity Coordinating Council (WECC) has decreased in recent years because of several generating resources operating at baseload with limited upward capability. That, in turn, could lead to reduced transmission path ratings into California and throughout WECC. Furthermore, the EPG found that a significant resource shift to more renewable resources in WECC, without corresponding attention to the thermal capability of generators, voltage support, and how generators perform during contingency events, could compound this issue. The impact, if any, would arise most likely during non-peak hours.

Mitigation and Operating Solutions to Date

Several strategies have been proposed and implemented to integrate variable renewable energy generation, primarily wind. These include wind forecasting, grid codes, curtailment, wind turbine modeling and verification, demand response, and transmission planning and development.

Wind Forecasting: In general, wind generation can be predicted more accurately the closer it occurs to actual operation. Wind generation can be predicted with about 90 percent or greater accuracy one hour ahead, with 70 percent accuracy nine hours ahead but only about 50 percent accuracy 36 hours ahead. The mean absolute error by installed capacity for wind forecasting in Denmark is typically between 8 and 9 percent, which is equivalent to a 38 percent forecast error by energy. In Germany, the root square mean error (RSME) of wind forecasts is 5 to 8 percent of installed wind capacity with maximum errors ranging from -30 to 40 percent of installed wind capacity. On a four-hour ahead basis in Germany, the RSME is 3.8 percent, with a maximum error ranging from –28 to 36 percent.

Contributors to wind forecasting errors include "phase errors," which occur when wind forecasts predict storms. In practice, the storm may occur a few hours ahead or few hours behind the wind forecast. Another contributor to wind forecasting errors is the relatively low spatial and temporal quality of meteorological data. Most forecasting has been focused on weather attributes such as precipitation and temperature, with a lower spatial and temporal resolution than is required for wind generation. Many business and governmental entities are becoming interested in finer, more precise forecasting, and that in turn may correspond to better data for improving wind forecasting.

In 2002, the CAISO became the first, and to date the only, regional transmission operator in the United States to offer centralized wind forecasting to predict the output of variable renewable energy generation. The Participating Intermittent Resource Program (PIRP) is voluntary. To date, only wind generation is enrolled in PIRP, although with several proposed large-scale solar projects in California, it is possible that solar will join wind in the PIRP program. In PIRP, the positive and negative imbalances associated with the 10-minute schedules of wind power generators are netted out and settled on a monthly basis, with the notion that these imbalances will cancel out over the month. Any net imbalances at the end of the month, positive or negative, are settled at the weighted average zonal market clearing price. The CAISO is allowed to charge penalties for excessive deviations of a generator compared to advance schedules but does not at this time. If the CAISO charges this penalty, participating intermittent resources in PIRP would be exempt.

Initially, PIRP was handicapped by missing telemetry data causing variations in the wind forecast; however, most of this type of error has been corrected. There are some market participant concerns regarding the re-allocation of costs from which participating intermittent resources are exempt. The CAISO is exploring making several enhancements and changes in hopes of reducing these cost concerns. These enhancements include increasing the forecasting fees for being in PIRP and subjecting power exports from participating intermittent resources to higher fees. In December 2006, the Federal Energy Regulatory Commission (FERC) approved the CAISO's petition to charge an export fee to PIRP facilities that export power out of the CAISO control area.

Grid Codes: A common approach taken by many transmission system operators to incorporate wind, is to adopt grid codes specific to wind generators. Germany introduced their wind grid code in 2003, followed by Denmark's TSOs in late 2004. Britain, Ireland, and the United States have since followed with wind grid codes in 2005.

The intent is to ensure that wind projects do not negatively impact reliability. A large amount of wind capacity tripping off-line in response to a grid disturbance could lead to a fall in voltage and/or frequency. That, in turn, could contribute to other generators tripping off the grid and could result in not having enough generation to meet load. The grid codes have emerged on a transmission operator or country basis, and differences between the grid codes have naturally resulted. To date, wind specific grid codes have required wind power facilities to address one or more of the following conditions to:

- Ride through grid faults
- Increase or decrease power generation at the TSO's request
- Supply reactive power
- Adjust power generation in response to frequency changes

- Control or limit ramping increases.

Generally, all wind grid codes have a fault ride-through requirement specifying that wind generators must stay connected for a period of time when faults occur on the transmission system and voltage drops. As indicated in Table ES-5, fault ride-through requirements differ by country.

Table ES-5. Examples of wind grid codes

Grid Code	Fault Duration (Milliseconds)	Voltage Drop During Fault (% Nominal)	Voltage Recovery (Milliseconds)
Denmark	100	25	1000
Germany (E. On)	150	0	1500
Ireland (Eir Grid)	625	15	3000
UK (NGT)	140	0	1200
Spain	500	20	1000
United States	150	0*	NA

***As of 2008. For 2007 and for normally cleared three-phase faults, wind turbines must be able to ride through voltages down to 15 percent at the point of interconnection for 150 milliseconds. Source: Milborrow, David. 2005b. "Going Mainstream at the Grid Face." *Windpower Monthly*, September 2005, p. 49. Reproduced by permission. United States provisions drawn from Federal Energy Regulatory Commission. December 12, 2005. *Order No. 661-A. Interconnection for Wind Energy*.**

A smaller number of countries also require wind turbines to provide frequency response in order to maintain the frequency at 50 Hz (the level in Europe). Wind turbines have a limited ability to provide frequency control as compared to conventional units. To meet this requirement, wind turbines must be operated at less than full output, such that blade pitch can be adjusted to increase generation when called upon. This is an option on newer pitch controllable turbines. Ireland requires wind generators to provide primary frequency control of 3-5 percent of power output and to provide secondary frequency control if called upon. Denmark and the United Kingdom require wind generators to provide frequency control after a system fault or if part of the grid is isolated. Similarly, transmission system operators are also requiring wind generators to stay on-line during frequency deviations, as indicated in Figure ES-4.

Grid codes also generally require wind turbines to operate continuously at rated output in normal voltage ranges, to stay on-line during voltage changes within a specified range, and to supply reactive power. For instance, E. On Netz in Germany requires wind turbines to continue to supply reactive power for up to three seconds after a voltage drop. Sweden, Norway and Spain also have provisions for wind turbines and reactive power.

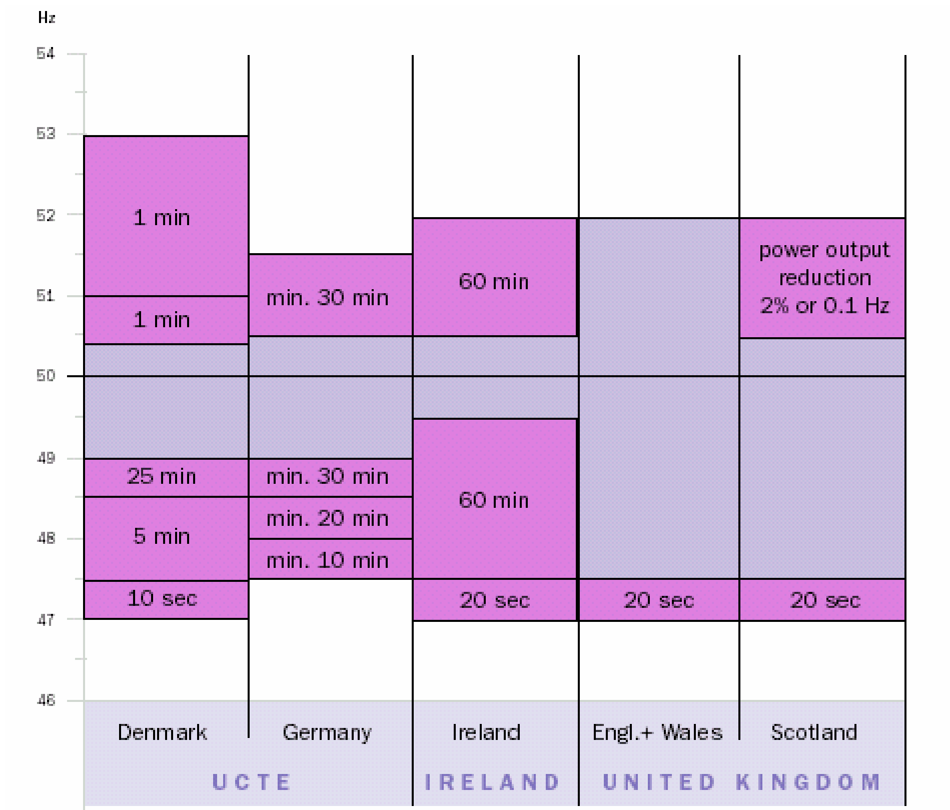


Figure ES-4. Frequency control requirements by selected country

Source: Van Hulle, Fran. 2005. *Large Scale Integration of Wind Energy in the European Power Supply*. Brussels, Belgium: European Wind Energy Association. Available at http://www.ewea.org/fileadmin/ewea_documents/documents/publications/grid/051215_Grid_report.pdf.

In the United States, FERC adopted a grid code in 2005 for wind turbines. A WECC task force is also considering possible changes to WECC's current low-voltage ride-through standard to lower the minimum voltage tolerance period to zero at the point of interconnection for 12 cycles (about 1/5 of a second).

Wind Turbine Modeling and Validation: A common issue with wind development is the need to improve the modeling of wind projects for determining the potential impacts on system reliability during the evaluation of interconnection applications. Lack of knowledge by transmission system operators about wind; the increasing size of wind projects; and the often weak transmission network that wind projects were attempting to interconnect to have made interconnection modeling a challenge. The WECC Wind Generator Modeling Group is preparing wind turbine generator models. In Europe, continued growth of wind energy in some countries may be conditioned on not only resolving uncertainties about the grid impacts of wind turbines but also on the availability of validated analytical tools and models. ESB in Ireland has instituted certification requirements for wind turbine models to be used in system interconnection studies as part of Ireland's grid code.

Demand Response: Demand response may help integrate larger amounts of wind power by moving consumption from when wind production is low to times of higher wind production, thereby lessening the requirement for reserves from conventional power plants. One example researched in Denmark is to use electricity production from wind generation during off-peak hours for district water heating instead of other fuels. So far, participation in demand response programs has been relatively small in Europe and in the United States, although regulatory and industry interest is growing. California has set targets for utilities to meet 3 percent of its annual peak demand with demand response, increasing 1 percent per year to 5 percent by 2007 and favors demand response and energy efficiency over other resources in meeting new electricity demand.

Wind Power Curtailment: Maximum wind production can be several times larger than average wind production, meaning that at 20 percent wind penetration by energy, wind production may equal consumer demand for some hours. Curtailment of wind generation may be necessary if the amount of wind generation at a specific time is more than what the grid can reliably handle. In fact, for grids with small control areas that are dominated by thermal generation that may not be very flexible, wind curtailments could occur at penetrations as low as 10 percent.

In Northern Germany, E. On Netz implemented curtailment policies, or "generation management" as described by E. On Netz, for wind generators in the Schleswig-Holstein region in mid-2003, covering 700 MW (about 1/3 of the wind capacity in that region), and expanding it to Lower Saxony in 2005. If overload conditions are present, E. On Netz identifies the region of concern and sends a signal to wind projects to adjust output accordingly, defining the maximum active output that the region's wind projects can provide to the grid. Until new transmission capacity is added, E. On Netz will not interconnect new wind projects in Schleswig-Holstein unless the wind generators participate in E. On Netz's generation management program. Spain also curtailed wind generation in 2004 when wind power penetration exceeded 12 percent of demand, due to local grid limitations. These wind curtailments occurred less frequently in 2005.

Transmission Planning and Development: Strong grid interconnections have played a part in helping Denmark manage its high level of wind production. In general, though, there is limited interconnection between national and regional electricity markets in Europe, and current trans-country interconnections can be heavily loaded. The International Energy Agency predicts that $1.8 trillion of transmission and distribution investments are necessary by 2030 simply to meet demand growth and to upgrade existing assets in Europe. California has extensive interconnections with the Pacific Northwest and with the Desert Southwest, and the state is working on new transmission that will be necessary if California is going to meet its 20 percent RPS by 2010. A number of transmission planning activities are occurring both inside and outside of California. In August 2006, the CAISO Board of Governors approved the Sun Path project that will add 1,000 MW of transmission capacity to Southern California providing access to geothermal and solar resources in the Imperial Valley. The CAISO Board of Governors is considering proposed transmission projects in Tehachapi and the Lake Elsinore Advanced Pump Storage (LEAPS) project. Outside of California, more than a dozen transmission projects have been proposed, with some of these proposals targeting California as the ultimate market. Many of these proposals are at a very early stage, and not all of them may be constructed.

Conclusions

Nearly two-thirds of the world's wind installed capacity is in Europe, with Germany, Spain, and Denmark alone accounting for one-half of the world's installed wind capacity. Wind development in Europe, at least initially, differed from the larger utility-scale projects in the United States, particularly in Denmark and Germany, where wind development consisted of smaller (but numerous) wind projects interconnected to the distribution grid. That type of wind development in Denmark and Germany took advantage of the geographic diversity of wind resources to smooth some of the variability in wind.

Similar management strategies between the United States and Europe have begun to emerge as wind development has expanded to other countries with less robust grid infrastructure, as compared to Denmark and Germany, and as wind development has tended towards utility-scale projects that are common in the United States. The implementation of grid codes (although varying in specifics from country to country) is one such example. The need for transmission in both Europe and the United States, not just for wind generation but for all types of generation, is another similarity. Considerable transmission planning and activity is underway in both Europe and the United States.

The particular circumstances in each country, state or region will determine the ease of integrating variable renewable energy generation. These factors include the generating mix; the flexibility of resources in mix; whether there are robust day-ahead markets with deep resource stacks; the location of wind resources; transmission availability; and the size of control areas. Wind integration will almost certainly be more challenging in small control areas, in areas with limited interconnections, or in areas with a small load and/or small resource stacks as compared to regions with larger control areas, extensive interconnections or large loads and/or deep resource stacks. Because these circumstances can vary dramatically, caution should be used in comparing countries or regions with each other.

This report examined how countries overseas have incorporated variable renewable energy generation, what operating strategies have been used to integrate variable renewable energy generation, what lessons have been learned, and whether that experience is transferable to California. For a variety of reasons, the report focused mostly on wind, given that there is more grid-connected wind capacity worldwide than solar; the experience with wind is more widely reported; and the development to date of solar systems has been of small, distributed systems and, at least as of now, does not face the same system integration issues as wind power.

Some highlights of integration strategies and findings from various country reports include:

- Strategies implemented to incorporate wind include wind forecasting, grid codes, curtailment, wind turbine modeling and verification, demand response, and transmission planning and development.
- To date, grid codes have featured these major themes: requiring wind turbines to ride through grid faults; increasing or decreasing power generation at the TSO's request; supplying reactive power; adjusting power generation in response to frequency changes; and controlling or limiting ramping increases.

- Various European transmission system operators have implemented more control requirements for wind than have been seen in the United States so far, such as ramp rate limits and the requirement to provide reserves and frequency control. In general, these control requirements have been a function of small control areas or limited transmission interconnections, or both.
- Some of the more stringent wind control strategies have been proposed in countries that have little or no grid interconnections, and these particular circumstances need to be kept in mind when comparing international wind integration experiences. Ramping events will be of more concern to small grids, or grids with few external interconnections, or grids with a large concentration of wind projects in one region.
- Countries with "must-take" requirements in their renewable energy feed-in laws tend to have the toughest grid code provisions with regards to wind curtailment.
- In describing various ancillary services, Europe and the United States use different terminology. In Europe, primary reserves assist with the short-term, minute-to-minute balancing and control of the power system frequency, and is equivalent in the United States to regulation. Secondary reserves in Europe take over for primary reserves 10 to 30 minutes later, freeing up capacity to be used as primary reserves. The closest terminology in the United States for secondary reserves is either operating reserves or load following reserves, which may include both spinning and non-spinning components. Longer-term reserves in Europe are called tertiary reserves and are available in the periods after secondary reserves. Tertiary reserves are closest to supplemental reserves in the United States, although the time scales may be different between Europe and the United States.
- Reconstituting existing reserve services may be necessary as higher levels of variable renewable energy generation is added.
- Submitting schedules with shorter periods of time before the real-time market begins will allow for more accurate predictions of wind generation, although some trade-offs are involved.
- Various wind integration studies and transmission system operators have reported some operating issues with wind generation, such as minimum load and high ramp rates. A New Zealand wind integration study used minimum load to determine how much wind could be accommodated on its grid.
- For ramping, various studies suggest that wind will ramp up and down within ±10 percent of capacity much of the time over an hour. Handling wind ramping could be managed with sufficient regulation or load following generation; wind forecasting to predict variability and ramping events; performance limits on the wind generation such as ramp rate limits; or sharing reserves or energy imbalances over multiple control areas.
- Efforts are also underway on improving the modeling of wind projects for determining the potential impacts on system reliability during the process of evaluating interconnection applications from wind generators.

In terms of wind integration costs, the results of various studies conducted to date in the United States and overseas have been reasonably consistent. Overall, the findings can be summarized as follows:

- The cost for integrating wind is non-zero and increases as the proportion of wind generation to conventional generating resources or peak load increases;
- Reserve costs attributed to wind integration are relatively small at wind penetration levels of less than 20 percent. How the variability and uncertainty of wind generation interacts with variations in load and load forecasting uncertainty has a large impact on the level of wind integration costs.
- Level of geographic concentration of wind projects also affects wind integration costs.
- Unit commitment impacts have been a major focus of wind integration studies in the United States but have not been addressed as extensively in the European studies to date.
- Based on several European studies that estimated the costs of additional reserves with wind generation, costs were generally less than $6/MWh at wind energy penetration levels up to 20 percent, although the costs varied significantly among the individual studies.
- Reserve costs for wind generation are dependent on the characteristics of the grid that is integrating wind, the adequacy and characteristics of the existing reserves, and the specific reserve requirements for each grid.
- Studies estimating the capacity credit of wind power in Europe determined that wind has a capacity credit greater than zero, and also that the capacity credit decreases as the level of wind generation rises.
- Factors that affect the capacity credit of wind include present levels of wind generation on the grid; the quality of the wind resource; the capacity factor of the wind projects; whether demand and wind generation are correlated or uncorrelated; the degree of system security; and the strength of the transmission interconnections.

As time goes on, more similarities than differences are apparent between Europe and the United States as variable renewable energy generation increases in market penetration. These similarities are sparking information exchange and transfer through forums such as the IEA, the Institute of Electrical and Electronics Engineers and the Utility Wind Integration Group (UWIG). That, in turn, can help elevate prominent issues and make the task of developing solutions and options for integrating variable renewable energy generation easier.

Benefits to California

California has perhaps the most significant and diverse RPS in the United States in terms of the level (20 percent), timeframe (2010) and the amount of renewable energy capacity that may be required to meet the target. Transmission and the integration of variable renewable energy generation remain challenges that need to be addressed in order for California to meet its RPS goals. Various countries in Europe have experience with integrating high levels of variable renewable energy generation. By reviewing and highlighting strategies and practices that have been used to integrate wind in other states and in other countries in this report, the IAP may incorporate some of these strategies and practices as options to test potential effectiveness in integrating variable renewable energy generation in the state. The hope is that California projects and utilities can begin to evaluate and incorporate some of these approaches and to test their effectiveness in integrating renewables.

1.0 Introduction

Growth in wind and solar has been surging in recent years. Wind capacity worldwide increased by 25% in 2006 as compared to 2005, and Europe reached its 2010 goal of 40,000 MW installed wind capacity five years early (Global Wind Energy Council 2006). Solar cell production has been increasing at over 25% annually, and shortages in materials for solar cells and solar cells themselves have been reported (Earth Policy Institute 2004).

With growth come concerns over how the electricity grid will integrate variable renewable energy resources such as wind and solar. This report reviews the current studies, practice and experience integrating variable renewable energy generation. The approach for this paper has been to review numerous reports, presentations and conference papers and to focus on issues identified with integrating variable renewables. For a variety of reasons, this paper will primarily cite examples for wind given:

- there is more grid-connected wind capacity worldwide than solar;
- the experience with wind is more widely reported; and
- the development to date of solar systems has been predominantly of small, distributed systems and, at least as of now, does not face the same system integration issues as wind power.

With a number of incentive programs for solar, particularly in Germany and Spain, grid-connected solar generation is starting to increase. Of the largest 20 grid connected photovoltaic (PV) power plants in the world, 16 have been installed in 2004 or later (PVResources.com 2006).

Two-thirds of the 74 GW of worldwide wind capacity is located in Europe, making Europe an interesting case study for studying the grid impacts of wind. Although wind provides about 3% of Europe's electricity, some regions have considerably higher wind penetrations as indicated in Table 1, such as Western Denmark (>20%) and Schleswig Holstein in Germany (~30%) (Holttinen 2004). Ultimately, some estimates indicate that wind may provide 12% of Europe's electricity demand by 2020 and 30% by 2030 (Van Hulle 2005).

Table 1. Examples of wind power penetration levels, 2005

Country or region	Installed wind capacity (MW)	Total installed power capacity (MW)	Average annual penetration level[a] (%)	Peak penetration level[b] (%)
Western Denmark	3,128	7,488	~23	>100
Germany:	18,428	124,268	~5	n.a.
Schleswig-Holstein	2,275	———[c]	~28	>100
Spain	10,028	69,428	~8	~25%
Island systems:				
Swedish island of Gotland[d]	90	No local generation in normal state	~22	>100

n.a. = Not available
[a]Wind energy production as share of system consumption
[b]Level at high wind production and low energy demand, hence, if peak penetration level is >100% excess energy is exported to other regions.
[c]German coastal province
[d]2002 data. The island of Gotland has a network connection to the Swedish mainland.

Source: Adapted from Soder, Lennart and Ackerman, Thomas (2005). "Wind Power in Power Systems: An Introduction," In T. Ackerman (Ed.), *Wind Power in Power Systems* (pp. 25-51). England: John Wiley and Sons, Ltd. Updated and adapted by the author. Reproduced with permission.

The majority of wind development in Europe has taken place in three countries: Denmark, Germany, and Spain. Together, those three countries account for 50% of worldwide installed wind capacity. Wind development in Denmark and Germany has consisted of small installations of wind turbines that are widely distributed, taking advantage of the geographic dispersion of wind resources and providing some smoothing of wind's variability.

Denmark and Germany also have strong interconnections with other countries, allowing the export of surplus wind production and the import of power when wind production is low. More recent wind development in other countries has occurred where there is little or no grid interconnection with other countries. Examples include Spain, Ireland, and Britain, where international grid interconnections are more limited.

As on-shore wind development in Europe becomes more saturated, wind development will likely move offshore and be more concentrated in smaller geographic areas. Over 54 GW of offshore wind is in various stages of planning in Europe (Liebreich and Young 2005). In Germany alone, between 25 and 30 GW of offshore wind capacity is planned for the North and Baltic Seas by 2030 (Deutsche Energie-Agentur 2005). Not only will wind capacity be more concentrated, losing some of the smoothing effects for wind from geographic dispersion, but some of the proposed offshore wind development is in regions that already have high wind penetration, such as Northern Germany, further adding to the integration challenges.

Although present operating practices have allowed Europe to manage wind's variability, there is some thought that new strategies will be necessary to accommodate the future growth of wind. The Union for the Coordination of Transmission of Electricity (UCTE), the association of transmission system operators from 23 European countries, issued a statement in May 2005 calling for more grid infrastructure and other actions to integrate wind in the European grid (UCTE 2005). The European Wind Energy Association also anticipates that some changes may be necessary in operating the grid at higher levels of wind penetration, and suggested that planning begin for those changes (Van Hulle 2005). The IEA is sponsoring an annex, "Design and Operation of Power Systems with Large Amounts of Wind Power Production," that began in mid-2006 (International Energy Agency 2006). Finally, the European Transmission System Operators (ETSO), the association of transmission system operators in Europe, announced plans to conduct a Europe-wide wind integration study. The planned study will encompass 16 TSOs in 14 countries that represent the four major synchronous electricity grids in Europe. Early results focusing on wind integration solutions in each synchronous grid are expected in 2008 (ETSO 2006).

The grid situation is different as wind development spreads to other countries around the world. India, for example, does not have a national grid but instead has five state-owned regional grids, with the grids in rural areas tending to be weak. Periodic power outages in India are common and cause up to $25 billion in economic damages annually, according to the government of India (Sieg 2006). India has moved into fourth place among countries with the most installed wind capacity and met its 2012 target of 5,000 MW of wind capacity in 2006 (Rajgor and Mathews 2006). Similarly, China's explosive economic growth has exceeded available electricity supplies and led to electricity shortages, with two-thirds of the provinces in China experiencing blackouts in 2004 (Ku et al. undated). China has about 2,600 MW of wind capacity and has set a goal of 30 GW of wind by 2020 (Jianxiang 2006). Wind projects in China must meet a 50% local content standard for projects approved before 2005, increasing to 70% for projects approved after 2005.

The particular circumstances in each country, state or region will determine the ease of integrating variable renewable energy generation. Among other things, this includes such factors as whether the generating mix has flexible resources or not; whether there are well-functioning and deep hour-ahead and day-ahead markets; whether the wind projects are relatively spread out or concentrated; whether there is available transmission; and whether the control areas are fairly broad or relatively small. Because these circumstances can vary dramatically, caution should be used in comparing countries or regions with each other. Wind integration will almost certainly be more challenging in small control areas, in areas with not much interconnections, or in areas with a small load and/or small resource stack as compared to regions with larger control areas, extensive interconnections or large loads and/or deep resource stacks. Some of the more stringent wind control strategies have been proposed in countries that have little or no grid interconnections, and these particular circumstances need to be kept in mind when comparing international wind integration experiences.

That said, the international experience with wind offers some lessons for regions in the United States that have or are expecting significant additions of wind capacity. Already, some countries have developed wind forecasting strategies and grid codes addressing wind power systems that have formed the basis for similar actions in the United States. That trend is likely to continue.

More experience with wind integration will be gained as countries add wind to their generating mix.

The report is organized as follows. The remainder of this chapter provides an overview of worldwide wind and solar capacity. Chapter 2 reviews the results of wind integration studies and practices in the United States and Europe. Chapter 3 discusses the effects of market structure and reviews how the capacity credit of wind is determined internationally and in the United States. Chapter 4 describes grid operation issues with wind to date. Chapter 5 reviews the solutions that grid operators have developed to handle the variability of wind generation. Chapter 6 presents some findings and implications for California, while Chapter 7 provides conclusions. Country-specific profiles are offered in the appendix on four of the five leading countries in the world in regards to installed wind capacity: Germany, Spain, India, and Denmark. (The United States is the other leading country in installed wind capacity.)

1.1. Worldwide Wind and Solar Capacity

Wind power generation has been rapidly growing in power systems throughout the world. Table 2 shows global wind energy generating capacity at the end of 2006, as well as wind capacity additions in 2006. A majority of the wind power capacity has been installed in Western Europe, specifically in Denmark, Germany and Spain; however, emerging wind energy contributors include India, Japan, and China. Indeed, India surpassed Denmark in 2005 as the fourth leading country in installed wind capacity (GWEC 2006).

Worldwide solar installations are also surging, with 1,460 MW installed in 2005 (see Figure 1). Germany accounted for 837 MW of this total, representing 57% of the market. Overall, installed solar generating capacity exceeds 5 GW worldwide, and projections are that annual solar installations will increase to between 3,200 MW and 3,900 MW by 2010 (Solarbuzz 2006).

Table 3 presents the twenty largest solar grid-connected projects in the world. Of these twenty, only four were installed before 2004. Large-scale solar thermal concentrating projects are beginning to appear as well, with Spain planning 795 MW of parabolic trough and power tower projects (Western Governors Association 2006).

Table 2. Global wind energy capacity by country, 2006

Country	2006 Capacity Additions (MW)	2006 Total Installed Capacity (MW)
Germany	2,233	20,622
Spain	1,587	11,615
Denmark	12	3,136
Italy	417	2,123
UK	634	1,963
Portugal	694	1,716
France	810	1,567
Netherlands	356	1,560
Austria	146	965
Greece	173	746
Ireland	250	745
Sweden	62	572
Norway	47	314
Belgium	26	193
Poland	69	153
Other (1)	192	556
Europe Total	**7,708**	**48,545**
United States	2,454	11,603
Canada	776	1,459
North America	**3,230**	**13,062**
India	1,840	6,270
China	1,347	2,604
Japan	333	1,394
Taiwan	84	188
South Korea	75	173
Philippines	0	25
Other (2)	0	13
Asia	**3,679**	**10,667**
Australia	109	817
New Zealand	3	171
Pacific Islands	0	12
Total Pacific Region	**112**	**1,000**
Brazil	208	237
Mexico	85	88
Costa Rica	3	74
Caribbean (w/o Jamaica)	0	35
Argentina	0	27
Columbia	0	20
Jamaica	0	20
Other (3)	0	7
Latin America	**296**	**508**

Table 2: Global wind energy capacity by country, 2006 (continued)

Country	2006 Capacity Additions (MW)	2006 Total Installed Capacity (MW)
Egypt	85	230
Morocco	60	124
Iran	27	48
Tunisia	0	20
Other (4)	0	11
Africa & Middle East	**172**	**433**
World Total	**15,197**	**74,215**

(1) Bulgaria, Croatia, Cyprus, Czech Republic, Estonia, Finland, Faroe Islands, Hungary, Iceland, Latvia, Liechtenstein, Lithuania, Luxembourg, Malta, Romania, Slovakia, Slovenia, Switzerland, Turkey, Ukraine.

(2) Bangladesh, Indonesia, Sri Lanka, Russia;

(3) Chile, Cuba, Mexico.

(4) Cape Verde, Israel, Jordan, Nigeria, South Africa

Source: Global Wind Energy Council Press Release. "Global Wind Energy Markets Continue To Boom – 2006 Another Record Year." February 2007. Available at http://www.gwec.net/uploads/media/07-02_PR_Global_Statistics_2006.pdf

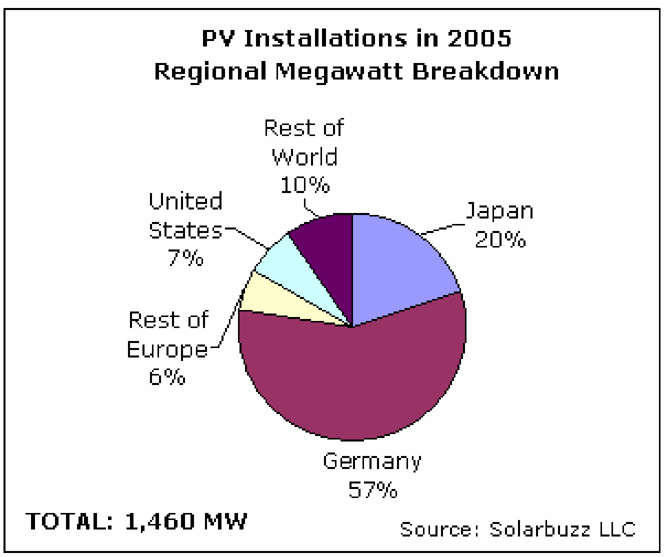


Figure 1: Worldwide PV installations in 2005 (MW)

Source: "2006 World PV Industry Report Highlights: World Solar Market. Up 34% in 2005; 837 MW Installed in Germany." Solarbuzz LLC, March 15, 2006. Available at http://www.solarbuzz.com/Marketbuzz2006-intro.htm.

Table 3. Twenty largest grid-connected photovoltaic systems

World Rank	Project	Location	Size (MW)	Date Installed
1	Solarpark Pocking	Pocking, Germany	10	April 2006
2	Solarpark Muhlhausen	Muhlhausen, Germany	6.3	December 2004
3	Freiland SonnenStrom	Miegersbach, Germany	5.27	Part 1, June 2005 Part 2, December 2005
4	Burstadt Plant	Burstadt, Germany	5	February 2005
5	Solarpark Leipziger Land	Espenhain, Germany	5	August 2004
6	Springerville Generating Station	Tuscon, Arizona, USA	4.59	2001-2004
7	Solarpark Saarbrucken	Saarbrucken, Germany	4	Part 1, June 2004 Part 2, September 2005 Part 3, December 2005
8	Solarpark Geiseltalsee/Merseburg	Geiseltalsee/Merseburg, Germany	4	September 2004
9	Solarpark Zeche Gottelborn (Part 1)	Gottelborn, Germany	4	August 2004
10	Solarpark Hemau	Hemau, Germany	4	2003
11	Fischer's Family Warehouse	Kronwieden/Dingolfing, Germany	3.7	October 2005
12	Michelin Reifenwerke KGaA	Homburg, Germany	3.5	December 2004, expanded June 2005
13	Solarpark Penzing	Penzing, Germany	3.45	December 2005
14	Co.Muckenhausen roof mounted plant	Dingolfing, Germany	3.3	October 2004
15	Centrale di Serre Persano, ENEL research center	Serre, Italy	3.3	1995
16	Castejon power plant	Castejon, Navarre, Spain	2.44	February 2006
17	Solarpark Hofkirchen, part of Solarpark Donau	Hofkirchen, Germany	2.37	August 2005
18	Solaranlage Darast Nord	Bad Gronenbach/Woringen, Germany	2.3	November 2005
19	Floriade exhibition hall PV System	Vijfhuizen, Netherlands	2.3	April 2002
20	Michelin Reifenwerke KGaA	Bad Kreuznach, Germany	2.2	2005

Source: "World's Largest Photovoltaic Power Plants," pvresources.com. Accessed June 2006. Available at http:///www.pvresources.com/en/top50pv.php

2.0 Wind Integration Studies in the United States and Worldwide

This chapter will review the wind integration studies that have been conducted in the United States and in various countries around the world. These studies often emphasize the role of ancillary services and the impact of wind power on the need for and availability of these services. We will begin by examining how ancillary services are defined in Europe and in the United States.

Electric power systems need a variety of ancillary services to maintain grid operation and reliability. There is not general agreement on how these services are defined, and as explained further below, the United States and Europe define these services differently. Even within the United States, there may be differences in what is considered ancillary services. In general, though, the following are considered necessary to maintain reliable grid operation:

- *Regulation*—Maintaining system frequency through varying certain generating units, typically with automatic generation control (AGC), up and down in response to very fast, unexpected changes in load and generation.
- *Load Following*—Ramping generation up or down to react to the change in expected load patterns, such as increasing loads in the morning and decreasing loads late in the day.
- *Spinning Reserve*—Generating capacity, typically synchronized to the grid, that can maintain reliability if a generating unit or transmission line is tripped off-line.
- *Supplemental reserves*—This performs a similar function to spinning reserves, i.e., maintaining reliability in case of the loss of a major generating unit or transmission line, but the generators providing this service are not generally synchronized (non-spinning) to the grid and may need additional start-up time to contribute. In some instances, supplemental reserves may also replace spinning reserves after a period of time (Zavadil, et al. 2006). Regulation and load following are reserves used for normal system conditions, while spinning and supplemental reserves are used for contingency conditions.

Europe and the United States use different terminology in describing these various ancillary services (Table 4). In Europe, primary reserves assist with the short-term, minute-to-minute balancing and control of the power system frequency, and are equivalent in the United States to regulation. Primary reserves must be available within seconds and is typically done by synchronous generators that will automatically increase production when frequency drops or reduce production when frequency increases, or from load that can be dropped or reduced. Usually, the amount of primary reserve is defined by the largest power plant that can be lost while maintaining grid reliability. Secondary reserves in Europe take over for primary reserves 10 to 30 minutes later, freeing up capacity to be used as primary reserves. Sources for secondary reserves include quick-start gas turbines, pumped storage hydro projects and load reduction or shedding. Like primary reserves, secondary reserves may equal the largest generating unit, although a factor may be added to account for load forecast errors (Holttinen and Hirvonen

2005). The closest terminology in the United States for secondary reserves is either operating reserves or load following reserves, which may include both spinning and non-spinning components. Longer-term reserves in Europe are called tertiary reserves and are available in the periods after secondary reserves. Tertiary reserves are closest to supplemental reserves in the United States, although the time scales may be different between Europe and the United States. The terms primary and secondary reserves will be used when describing the international experience with integrating variable renewable energy generation.

In addition to using different terminology, Europe and the United States use different frequencies for the electric grid. Europe operates at 50 Hz and the United States operates at 60 HZ.

Table 4. Reserve definitions in Germany, Ireland, and the United States

	Short-term reserves	**Medium-term Reserves**		**Long-term reserves**
Germany	Primary reserve: available within 30 seconds, released by transmission system operator	Secondary reserve: available within 5 minutes, released by transmission system operator	Minute reserve: available within 15 minutes, called by transmission system operator from supplier	n/a
Ireland	Primary operating reserve: available within 15 seconds (inertial response/ fast response)	Secondary operating reserve: operates over timeframe of 15-90 seconds	Tertiary response: from 90 seconds onwards (dynamic or static reserve)	n/a
United States	Regulation horizon: 1 minute to 1 hour with 1- to 5-second	Load-following horizons: 1 hour within increments 5- to 10 -minute increments (intra-hour) and several hours (inter-hour)		Unit-commitment horizon: 1 day to 1 week with 1-hour time increments

Source: Gul, T. and Stenzel, T. 2005. *Variability of Wind Power and Other Renewables: Management Options and Strategies*. Paris: International Energy Agency.

Four electrically synchronous zones are present in Europe: the Nordic countries, the UCTE countries, Great Britain, and Ireland.

- The Nordic synchronous zone serves Finland, Sweden, Norway, and Eastern Denmark. Overall, 25 million people are served, and about 90 GW of generating capacity is located in this zone. The transmission system operators have organized a cooperative body known as Nordel for administering the Nordic electricity market. Total primary control reserve is 1,600 MW, consisting of operating reserves of 600 MW and a disturbance reserve of 1,000 MW.

- The UCTE zone serves about 500 million people in 23 countries, with about 603 GW of generating capacity located in UCTE. For UCTE, primary reserves must be activated within 30 seconds and cover the loss of up to 3,000 MW of production.
- The National Grid Company is the grid operator of the electricity grid in England, Wales and Scotland. About 81 GW of generating capacity is located in Great Britain, with interconnections to France (2,000 MW) and Northern Ireland (450 MW) and requires reserves to cover the loss of 1,320 MW.
- Two TSOs, the EirGrid and the System Operators Northern Ireland, administer the grid in Ireland, with a generating capacity of 7,600 MW and a DC cable to Great Britain that has an interconnection capacity of 450 MW. The system reserve is 400 MW.

Most of the wind capacity in Europe is on the UCTE and Nordel grids and, therefore, will be emphasized in this report (Van Hulle 2005).

2.1 Summary of Various Assessments of the Impacts of Wind on Reserves

A number of wind integration studies have been conducted, mostly involving simulating large amounts of wind capacity on an electricity grid. The assumptions and methodologies vary by study, making direct comparisons difficult. The results may differ because of the different characteristics of the electric grids being studied, the levels of wind penetration studied, and the different methods and tools that have been employed. Still, the study results for the amount and cost of reserves required for wind generation have been reasonably consistent, demonstrating modest impacts to a certain point and with higher impacts as wind penetration is increased.

Generally, the largest impact of wind is on secondary reserves. Wind has little effect on primary reserves, as the variations in wind power are random, and when aggregated with load and generation variations, the variations tend to mostly cancel each other out, with any increase attributable to wind being quite small. In addition, primary reserves are intended to cover the outage of a large plant or transmission line, and therefore can generally mitigate the much smaller short-term impacts of wind. As an example, Eltra, the former transmission system operator for Western Denmark (prior to its merger with Elkraft, the former transmission system operator for Eastern Denmark, to form Energinet.dk), did not change its primary reserve requirements of 35 MW, despite the increase in wind from zero to 20%. Elsewhere, the Réseau de Transport d' Electricité, RTE, the French grid operator, estimated that the short-term fluctuations of 10 GW of wind would not exceed 100 MW within one minute, and that current reserve requirements in France can tolerate that (Gul and Stenzel 2005). Spain also has determined that additional primary reserves are not necessary from the amount of wind on the Spanish grid (Eriksen et al. 2005).

Wind integration studies conducted in the United States have found similar results. A General Electric (GE) study for NYSERDA determined that another 36 MW of regulation (primary reserves in European terminology) would be required to accommodate 3,300 MW of wind capacity (about 10% market penetration), but that the New York Independent System Operator had sufficient existing regulation capabilities to handle the additional need. The GE study also determined the New York ISO had sufficient resources to accommodate the additional load following (secondary reserves in European terminology) and hourly variability from incorporating the additional wind capacity (Piwko et al. 2005). Similar findings of modest incremental impacts for regulation and load following were made in wind integration studies conducted in Minnesota and Colorado, both of which involved the Xcel utility system (Zavadil et al. 2006).

Wind power may cause an increase in primary reserves, however, if many wind turbines drop off the grid at the same time, such as during a storm, that may trip off wind turbines. The probability of this event occurring will differ from country to country and may occur over a period of several hours. In Denmark and Germany, high wind speeds happen only a few times per year, and because of the geographic diversity of the small groups of wind installations spread across the country, an immediate shutdown of all the wind turbines is not likely to occur (Ackerman and Morthorst 2005). For example, E. On Netz in Germany reported that wind generation dropped from 6,024 MW to below 2,000 MW but over a period of 10 hours on Christmas Eve in 2004 (E. On Netz 2005). In Denmark, all of the country's wind capacity was disconnected when a large storm with high winds rolled through the country on January 8, 2005. However, it took eight hours for 3,000 MW of wind capacity to disconnect, or about 375 MW per hour (Ackerman 2006). Impacts of these events would be more pronounced in the unit commitment time frame as opposed to the time frame for primary and secondary reserves and highlights the role for wind forecasting, as discussed later in this report.

The results from Denmark and Germany may be different in countries with more concentrated, large wind projects that may shut off quickly during high wind events, and/or in countries where high wind speeds occur more frequently. One example is New Zealand, where high winds surpass the cut-out speeds of wind turbines about every three or four days. More primary reserves may be necessary under these circumstances (Ackerman and Morthorst 2005). However, a separate wind integration study in New Zealand determined that more primary or secondary reserves would not be necessary until wind capacity exceeds 1,000 MW (Energy Link Ltd. 2005).

Network faults that result in frequency or voltage variations may cause wind turbines to disconnect from the grid, possibly requiring additional primary reserves. As discussed later in this report, the proliferation of grid codes requiring wind turbines to stay on-line during network faults for varying periods of time, depending on the particular grid code, will likely mitigate this occurrence and the need for additional primary reserves (Ackerman and Morthorst 2005).

In 2005, the German energy agency Deutsche Energic-Agentus, otherwise known as dena, commissioned a large-scale study of the potential grid impacts of incorporating large amounts of wind in the future. With regard to reserves, the dena study found that an average of 1,200 MW and a maximum of 2,000 MW of wind-related positive regulation (generation coming on-line to fill in for generation going off-line or producing less than expected) was needed on a day-ahead basis in 2003 to support the 14,500 MW of installed wind capacity in Germany at that time. Dena projected that amount would increase to an average of 3,200 MW and a maximum of

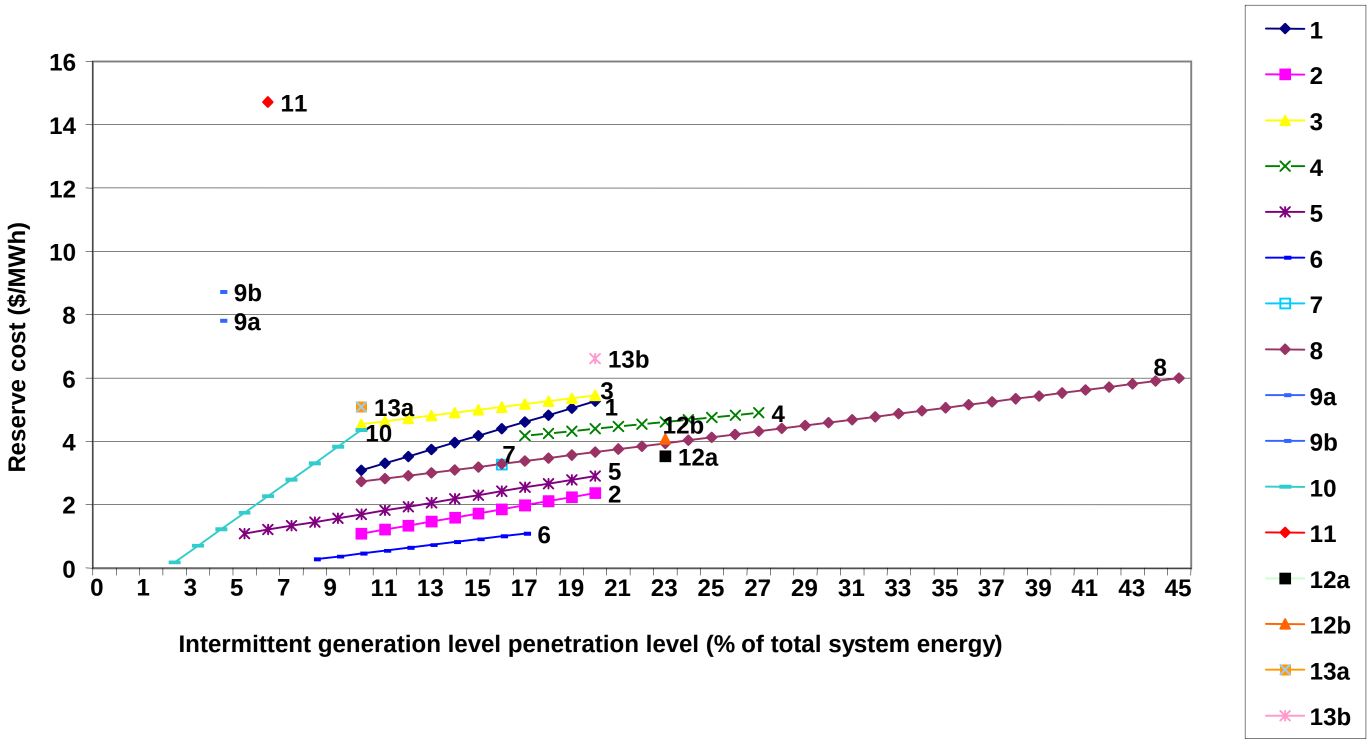
7,000 MW by 2015. The average equates to 9% of the installed wind capacity, and the maximum to 19.4%. For wind-related negative regulation (generation backing down to accommodate generation coming on-line or producing more electricity than expected), an average of 750 MW and a maximum of 1,900 MW was required on a day-ahead basis in 2003, and would rise to an average of 2,800 MW and a maximum of 5,500 MW in 2015. The average is equivalent to 8% of installed wind capacity and the maximum is equivalent to 15.3% of installed wind capacity. The dena study determined that the positive and negative reserve requirements can be met with existing generation, and that no new generation would be necessary (dena 2005). The IAP will estimate reserve requirements and determine if additional reserves are necessary.

2.2 Summary of Estimated Cost Impacts for Additional Reserves from Wind Energy

A recent literature review of several European studies that estimated the costs of additional reserves with wind generation found that these costs were generally less than $6/MWh at wind energy penetration levels up to 20%, although the costs varied significantly among the individual studies. Figure 2 illustrates these results. These differences suggested that reserve costs for wind generation will be dependent on the characteristics of the grid that is integrating wind, the adequacy and characteristics of the existing reserves, and the specific reserve requirements for each grid. These results appear consistent with wind integration studies conducted in the United States that found these costs were relatively modest at wind penetration levels of under 20% (Table 5).

Despite the significant differences in the study methods and the characteristics of the power grids that were assessed, the findings from the European and United States research can be summarized as follows:

- The costs for integrating wind is non-zero and increases as the proportion of wind generation to conventional generating resources or peak load increases.
- Reserve costs attributed to wind integration are relatively small at wind penetration levels of less than 20%. These costs generally increase as the level of wind penetration increases.
- How the variability and uncertainty of wind generation interacts with variations in load and load forecasting uncertainty has a large impact on the level of wind integration costs.
- The level of geographic concentration of wind projects also affects wind integration costs. Greater spatial diversity of wind projects can lessen the fluctuations in wind output and therefore lessen wind integration costs (Zavadil et al., 2006).



	Country	Comments	Reference
1	UK	Lower bound estimates based on analysis from NEMCO (Australia), Lewis Dale of National Grid, SCAR Study and Millsborrow 2002	Mott MacDonald, 2003.
2	Nordic	Based on data collected in Finland, Sweden, Norway and Denmark	Holttinen, 2004.
3	UK	Dale, Milborrow SCAR, PIU studies	Dale et al 2003.
4	UK	Based on modeling efforts	Ilex & Strbac, 2002.
5	Ireland	Numbers derived from analysis of international experience, specifically, Denmark, US (BPA)	Millborrow, 2004.
6	Ireland	Study conducted for Sustainable Energy Ireland, estimates based on modeling analysis	Ilex et al, 2004.
7	Denmark	Actual costs to Eltra, Danish grid operator	Pedersen et al, 2002
8	UK	Estimates based on the technical standards of the National Grid Company	Milborrow, 2001a
9a	Spain	Low market costs of procuring the difference between predicted and actual generation	Fabbri et al, 2005.
9b	Spain	High market costs of procuring the difference between predicted and actual generation	Fabbri et al, 2005.
10	UK	Estimates based on 2001 market data for imbalances	Dale, 2002
11	Germany	Figures derived from analysis of E.On Netz study	Milborrow, 2005a
12a	Denmark	Low estimate based on Nord Pool balancing market (2002 prices	Ackerman et al, 2005
12b	Denmark	High estimate based on Nord Pool balancing market (2002 prices)	Ackerman et al, 2005
13a	Scotland	National Grid estimates for balancing costs with 10 % penetration of wind in the UK, as reported to the Scottish Parliament	National Grid Transco, 2004
13b	Scotland	National Grid estimates for balancing costs with 20 % penetration of wind in the UK, as reported to the Scottish Parliament	National Grid Transco, 2004

Figure 2. Range of findings of additional reserve costs from wind generators

Source: Adapted from Gross, Robert; Heptonstall, Philip; Anderson, Dennis; Green, Tim; Leach, Matthew; and Skea, Jim. (2006). *The Costs and Impacts of Intermittency*. London: United Kingdom Energy Research Center. Available at http://www.ukerc.ac.uk/content/view/258/852. British currency converted to U.S. $ using a conversion of $1.8717 per British pound, as of May 25, 2006. Denmark 2002 from Ackerman, Thomas; Morthorst, Poul Erik. 2005. "Economic Aspects of Wind Power in Power Systems." In T. Ackerman (Ed.), *Wind Power in Power* Systems (pp. 384-410). England: John Wiley and Sons, Ltd. National Grid numbers from National Grid Transco. 2004. *Submission to the Enterprise and Culture Committee: Renewable Energy in Scotland Inquiry*. Available at www.scottish.parliament.uk.. Sustainable Energy numbers from Sustainable Energy Ireland. 2004. *Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System*. Available at http://www.sei.ie/uploadedfiles/InfoCentre/IlexWindReserrev2FSFinal.pdf. See Reference for details.

Table 5. Estimated ancillary service costs from various wind integration studies in the United States

Study	Wind Penetration (%)	Regulation $/MWh	Load Following $/MWh	Unit Commitment $/MWh	Gas Supply Cost ($/MWh)	Total $/MWh
UWIG/Xcel	3.5	0	0.41	1.44	NA	1.85
PacifiCorp	20	0	1.64	3.00	NA	4.64
BPA/Hirst	7	0.19	0.28	1.00-1.80	NA	1.47-2.27
PJM/Hirst	0.06-0.12	0.05-0.30	0.70-2.80	N/A	NA	0.75-3.10
We Energies I	4	1.12	0.09	0.69	NA	1.90
We Energies II	29	1.02	0.15	1.75	NA	2.92
Great River Energy I	4.3	NA	NA	NA	NA	3.19
Great River Energy II	16.6	NA	NA	NA	NA	4.53
CA RPS Phase III	4	0.46	NA	NA	NA	NA
MN DOC/Xcel	15	0.23	0	4.37	NA	4.60
Xcel-PSCo	10	0.20	NA	3.32	1.26	3.72
Xcel-PSCo	15	0.20	NA	3.32	1.45	4.97

Sources: Parsons, Brian, et al: *Grid Impacts on Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*. Paper given to Nordic Wind Power Conference, May 22-23, 2006, Finland; and Smith, J.C.; DeMeo, E.; Parsons, B.; and Milligan, M. *Wind Power Impacts on Electric-Power-System Operating Costs: Summary and Perspective on Work to Date*. March 2004. Presented to the American Wind Energy Conference, Chicago, Illinois. www.nrel.gov/docs/fy04osti/35946.pdf. (accessed June 2, 2006).

Figure 3 illustrates the estimated potential increase in reserve requirements from integrating wind energy, according to several wind integration studies conducted in Europe. The methodology differs significantly by study, making these results not directly comparable. For example, the dena study in Germany estimated reserve requirements on a day-ahead basis, while the United Kingdom and Sweden studies estimated reserve requirements four hours ahead. The other studies estimated the impact on reserves from wind variability during the operating hours (Holttinen, et al. 2006). Generally, Figure 3 suggests that an increase is reserves is likely at higher levels of wind penetration.

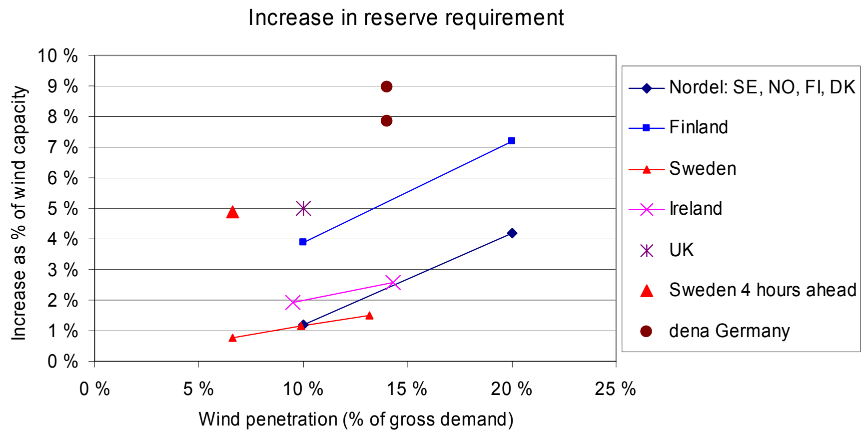


Figure 3. Estimated increase in reserve requirements from wind from various studies in Europe

Source: Holttinen, Hannele, Pete Meibom, Antje Orths, Frans Van Hulle, Cornel Ensslin, Lutz Hofmann, John McCann, Jan Pierik, John Olav Tande, Ana Estanqueiro, Lennart Soder, Goran Strbac, Brian Parsons, J. Charles Smith and Bettina Lemstrom. "Design and Operation of Power Systems with Large Amounts of Wind Power: First Results of IEA Collaboration." Global Wind Power Conference, Adelaide, Australia. September 18-21, 2006. http://www.ieawind.org/AnnexXXV/Meetings/Oklahoma/IEA%20SysOp%20GWPC2006%20 paper_final.pdf. (accessed November 8, 2006).

Newer wind integration studies will examine the potential grid impacts of higher levels of wind penetration than have been studied to date. One just-released study in Minnesota examined statewide wind penetration levels, by energy, of 15%, 20% anhd 25% of retail electric sales in Minnesota, which is equivalent to about 3,500 MW; 4,600 MW; and 5,700 MW of wind capacity. The study projected total wind integration costs of no more than $4.50 per MWh for up to 25% wind energy market penetration. This conclusion was based upon assuming consolidation of some of the balancing authority functions in the Midwest Independent System Operator, sufficient transmission, geographically diverse wind development; and the large energy market in the Midwest Independent System Operator's territory (Enernex 2006). The IAP will assess wind and solar market penetration levels of about 20% in the 2020 scenario.

Actual reported country experience with reserve costs is relatively limited. Reserve costs in Denmark were between €2.6 and €3/MWh, before the launch of the Nordpool balancing market in 2003. In 2002, the average cost of up-regulation (generation coming on-line to fill in for generation going off-line or producing less than expected) in the Jutlan-Furen area in Denmark was €12/MWh while the average cost of down-regulation was €7/MWh (generation backing down to accommodate generation coming on-line or producing more than expected). The costs of up-regulation typically exceeded the costs of down-regulation, perhaps because the marginal cost to generator of up-regulation is higher than for down-regulation. In 2003, Nordpool launched a common balancing market. Every TSO takes balancing bids, and Nordpool combines them in a common resource stack. If transmission congestion occurs, only the reserve bids from within the country can be used. Most of the reserves provided so far since the launch of the common balancing market has been from large hydro plants in Norway and Sweden (Ackerman and Morthorst 2005). In 2005, regulation costs in Denmark averaged 0.7 Euro cents/kWh for up regulation and 0.8 Euro cents/kWh for down regulation. The costs for regulation due to wind power averaged 0.2 Euro cents/kWh (Morthorst 2006).

E. On Netz in Germany has reported sharply higher numbers for primary and secondary reserve costs and contends that up to 80% of the installed wind capacity must be backed up by conventional power plants, termed "shadow capacity". Furthermore, because of limited forecasting accuracy, E. On Netz asserts that reserve capacity of 50-60% of installed wind capacity must be maintained. E. On said it spent €100 million in 2003 for costs connected to wind-related reserve capacity, or about €11.8 per MWh for the 8.5 TWh of wind generation in 2003 (E. On Netz 2004). E. On Netz forecasted primary and secondary reserve costs at €7/MWh by 2016 at a 16% wind penetration level, and an additional €15/MWh for the additional capacity needed to provide reserves (Auer 2004).

E. On Netz's costs have been challenged as unrepresentative and more reflective of inefficiencies from the four market zones in Germany than from reserve costs attributable to wind. A *Wind Stats* (a trade publication) analysis of E. On Netz's figures suggested that the utility did not balance out the fluctuations of wind with the fluctuations of load, making the balancing impacts of wind larger than may be the case from an overall utility system perspective. Furthermore, the same analysis suggested that if the four German zones were combined, imbalances would cancel each other out 60% of the time (Milborrow 2005a).

Perhaps further contributing to the high reserve costs cited by E. On Netz was the scheduling protocols that were in place until August 2004. Until that time, wind generation was scheduled in firm flat blocks, a schedule at odds with the variations of wind, between 9.5 and 33.5 hours before real-time electricity delivery. The day-ahead schedules could not be adjusted unless there was a significant increase or decrease in either generation or load. Therefore, differences in advance schedules and real-time deliveries were balanced through reserve capacity. In addition, the inability to update wind forecasts more frequently than day-ahead also could have contributed to the high reserve costs reported in Germany.

In 2004, Germany changed its feed-in law whereby each German TSO is allocated wind energy, and the costs of balancing wind energy, in proportion to their national load share and not their share of national installed wind capacity. These shares change monthly. Balancing costs, along with the wind tariff costs, are allocated to end-use customers in proportion to their share of total load. Effectively, the German TSOs commit to a share of wind energy a month in advance. Wind generation that exceeds the expected monthly average is typically sold in the market by the TSOs, most often the day-ahead market. If wind generation is less than the expected monthly average, then energy needs to be bought on the market (most often the day-ahead market). If wind power differs from the day ahead wind forecast, TSOs typically rely on reserves, or if it is known far enough in advance, on the intra-day market that began in January 2006.

For the intra-day market in Germany, power traders nominate the buyer and seller on each side of the transaction and transmission path, and the German TSOs confirm the transaction. Nominations must be in one-hour blocks and scheduled at least one hour in advance. In 2007, the intra-day market will move to every 15 minutes, with 45 minutes advance notice required. In September 2006 the European Power Exchange (EEX) in Leipzig, Germany, started a platform for intra-day trading. About 80 power traders participate in the platform, and transactions average about 2,000 MWh per day, with a high of 5,000 MWh per day. Bids usually range from 5 to 100 MW, with a maximum limit allowed of 1,000 MW. Prices range from €20-120 per MWh. By comparison, prices for reserves may range from €50 to €200 per MWh (sometimes over €1000 per MWh). The intra-day market could be used for balancing wind power, especially for covering wind forecast errors (Ernst 2006). With the advent of a more robust balancing market, the high balancing costs reported in 2003 by E. On Netz are not likely to be experienced again.

2.3 Unit Commitment Impacts

Planning and scheduling generation to meet demand and maintain reliability involves scheduling generation to meet expected loads in a time frame that can range from several hours to a few days, depending on the start-up, ramping and other characteristics of generating units on the grid. This process is known as unit commitment, and the time frame is known as the unit commitment time frame. Over-scheduling generation may increase costs and waste generation and fuel, while under-scheduling generation could result in expensive short-term market purchases, or in the worst case, have reliability implications if insufficient generation has been scheduled and not enough generation is available on short notice. Because wind generation is variable and may have characteristics opposite of load (i.e., wind projects may not generate when load is rising and vice versa), grid operators and utilities may incur additional unit commitment costs.

Unit commitment with significant amounts of wind generation has some uncertainty, and the flexibility of the other generators determine how easy or difficult unit commitment decisions with wind generation are. In addition, as discussed later, an accurate wind forecast can assist in unit commitment decisions. Wind generation can cause extra costs if power plant operation is less efficient because of changes in wind production and errors in wind forecasting. For a system with more baseload thermal generation, as opposed to those with more hydro, cost impacts are contingent on whether plants are over- or under-committed because of wind generation.

Although unit commitment has been a major focus of wind integration studies in the United States, unit commitment has not been addressed as extensively in the European studies to date (Gross et al. 2006). In Ireland, ESB National Grid (now known as EirGrid) conducted a system simulation to measure the impacts of wind generation on unit commitment. The study scaled output from existing wind projects with wind data from planned wind projects to create a power time series. ESB found that at high wind penetrations, the number of start-ups and ramping for gas turbines increased significantly (Holttinen et al., 2006).

2.4 Wind and Natural Gas Storage

A wind integration study conducted for the Public Service Company of Colorado (PSCO) in the United States estimated, among other things, the impacts of increasing amounts of wind on the natural gas purchases, consumption and storage. PSCO acquires natural gas on a day-ahead basis, and those purchases are based on the forecasted load and the plans for the commitment and utilization of natural gas generation. The question is whether the additional next-day uncertainty with wind generation may affect gas purchase and storage decisions. Because gas storage is limited, not purchasing enough natural gas may result in having to purchase power on the open market, whereas purchasing too much natural gas may waste fuel. The study compared the additional costs of purchasing and storing natural gas with varying amounts of wind energy versus a reference case and determined the additional costs (see Table 6). The additional gas storage needed to accommodate wind's variability provides a winter-summer hedging benefit, estimated at $1.00/MWh of wind energy at a 15% wind penetration. These benefits were credited back to wind generation (Zavadil et al. 2006).

Table 6. Estimated financial impacts on the Public Service Company of Colorado's gas supply due to wind generation variability and uncertainty

Wind Penetration	10%	15%
$/MWh Gas Impact No Storage Benefits	$2.17	$2.52
$/MWh Gas Impact with Storage Benefits	$1.26	$1.45

Source: Zavadil et al. 2006*. Wind Integration Study for Public Service Company of Colorado*, May 1, 2006. Available at http://www.xcelenergy.com/docs/corpcomm/PSCoWindIntegStudy.pdf.

2.5 Changes to Reserve Service

Reconstituting existing reserve services may be necessary as higher levels of variable renewable energy generation is added. One example may be to commit additional reserve services for expected "wind events", such as storms with high winds that could trip wind generators as the storm passes through (Energy Link Ltd. 2005).

Some grid operators are contemplating offering a separate reserve service for wind, or at the least, reconstituting their existing reserve services to reflect the addition of wind to their grid. EirGrid in Ireland is interested in proposing a new ancillary service known as wind following capability (WFC) that would be provided in addition to replacement reserves. The WFC would be scheduled to respond to unpredicted changes in wind output, and the amount needed would be dependent on the accuracy of wind forecasts, the amount of wind generation and capacity, the historical and projected variations in wind output, and the time horizon of the WFC service. Initially, EirGrid projects that 484 MW of WFC would be required for 1,100 MW of wind at a cost of about €4 million annually but believes this estimate could be lowered with good wind forecasting (Smith and Ryan 2005). The Alberta Electric System Operator (AESO) also has contemplated establishing a wind-specific ancillary service called wind following (Alberta Electric System Operator 2006).

Tying an ancillary service specific to a technology such as wind would be a significant and perhaps unwise departure from the existing practice of tying ancillary services to specific system needs. Existing reserve services may adequately accommodate the incorporation of variable renewable energy generation. To the extent more reserves are needed, a separate load following ancillary service in the 10-minute to multi-hour time frame could be established. Such a service is not directly offered and priced in the United States—the existing generation fleet inherently may have enough load following capability to provide it at little or no cost.

2.6 Implications for California

The California renewable portfolio standard (RPS) requires utilities to use "least-cost, best-fit" strategies for selecting renewable energy projects in bidding solicitations, including indirect system integration costs. The Energy Commission has sponsored previous work assessing integration costs for the current market penetration levels of renewable energy in California. The most recent report assessed integration costs for 2002 through 2004 and determined that the cost of regulation for wind and solar ranged from $0.24/MWh to $0.7/MWh. The report also found that the current level of renewable energy in California does not have a significant impact on the short-term load following market (Shiu et al. 2006). Previous research sponsored by the Energy Commission determined that California has a deep stack of available power resources and the current level of renewable energy in California would not have a significant impact on unit commitment.

The IAP will assess whether California has sufficient regulation and operating reserves (primary and secondary reserves in European terminology) to accommodate large amounts of variable renewable energy generation. Based on the research and experience to date, the following could be expected:

- The need for primary and secondary reserves will likely rise as the market penetration of variable renewable energy generation increases.
- Weather and high-wind-speed events may increase the need for primary and secondary reserves, although wind forecasting and grid codes for wind turbines may help minimize this need.

3.0 Market Structure and Capacity Credit

3.1 Market Scheduling and Balancing Requirements

Generally, submitting schedules with shorter periods of time before the real-time market begins will allow for more accurate predictions of wind generation, although some trade-offs are involved. Having a shorter period of time before the start of real-time market operations leads to a need for more flexible secondary reserves, or perhaps higher costs from the increased starting and stopping of conventional units, as those shorter periods of time will not allow sufficient time to change unit commitment decisions for conventional generating units (Gul and Stenzel 2005).

The final schedule closing times are generally a historical artifact and may not have a technological or economic basis. Most countries require final schedules to be submitted between 12 and 36 hours in advance, although the United Kingdom allows schedules to be changed up to one hour before real-time power operations begin, and the Australian power exchange allows rebidding up to 5 minutes before actual resource dispatch (see Table 7) (Gul and Stenzel 2005). In addition, Elbas, a short-term market where buyers and sellers can engage power transactions up to one hour before real-time, is operating in Finland and Sweden, although volume is reportedly thin (Matevosyan and Soder 2005). Germany launched a hour ahead market in 2006 (Ernst 2006b).

Table 7. Market closing times in various electricity markets

Market	Closing time
England and Wales	1 hour before the half-hour in question
Nordpool Elspot	12:00 p.m. before the day in question; no changes
(power exchange)	possible after 12:00 p.m.
Nordpool Elbas	1 hour before the hour in question; no changes possible after this
Australia Power Exchange	Rebidding possible until the resources are used for dispatch (i.e., up to 5 minutes before the time in question)
New Zealand Power Exchange	2 hours before the hour in question; different rules in place for wind generators
PJM Market Day-Ahead Market	12:00 p.m. before the day in question; no changes possible after 12:00 p.m.
California ISO	10:00 a.m. the day before for the day-ahead market. Hour-ahead closes two hours and fifteen minutes before real-time

Source: Ackerman, Thomas; Morthorst, Poul Erik. 2005. "Economic Aspects of Wind Power in Power Systems." In T. Ackerman (Ed.), *Wind Power in Power Systems* (pp. 384-410). England: John Wiley and Sons, Ltd. California information from the author. Reproduced with permission.

New Zealand added provisions to their scheduling rules for wind generators, who still must offer schedules two hours ahead like other generators but are required to submit revised schedules closer to real-time if expected changes in output exceed a tolerance band, generally considered to be 10 MW or 10% of expected output, whichever is smaller. Exemptions are possible for projects under 10 MW or for projects not connected to the grid, or if the expected change in output is less than 5 MW. In addition, wind generators must offer output into the market at $0.01 per MWh which is the lowest price a generator can offer in New Zealand, unless a generator bids zero in the must-run dispatch auction (Energy Link Ltd., 2005).

The United Kingdom recently went to a one-hour ahead scheduling system. Previously, the requirement was three-and-a-half hours advance notice, and market participants had to schedule in half-hour increments. If wind conditions changed in the short run, wind generators had to trade surpluses or deficiencies in the spot market, leading one person to remark that "the most profitable way of operating a wind farm so far has been to turn it off" (Gul and Stenzel 2005). It was estimated that the New Electricity Trading Arrangements, as the three-and-a-half hour requirement was called, imposed additional costs of between €3.6 per MWh to €5.7 per MWh for about 500 MW of wind power. However, some have criticized the one-hour schedule as encouraging market participants to schedule more spinning reserve than is necessary, either through over-contracting or running their plants at partial load, in order to avoid balancing penalties (Gul and Stenzel 2005). Elsewhere, the TSOs in Denmark are bidding some of the wind production on the day-ahead market in Nordpool to reduce scheduling of the conventional power plants (Holttinen 2004).

In Spain, the balance penalty is fixed annually via a regulated tariff. For 2004, the penalty was about €7/MWh. The balance penalty applies to deliveries higher or lower than 20% of the scheduled generation, determined further by the forecast error, which is the relative deviation between forecasted and actual hourly generation, or calculated as the Mean Absolute Percentage Error (Van Hulle 2005).

3.2 Resource Delivery (Capacity Credit)

Wind generators occupy a unique place in the determination of capacity value. Wind generators typically have very high mechanical availability, exceeding 95% in many instances (i.e., the forced outage rate is often below 5%). However, because wind generators only generate electricity when the wind blows, a wind generator arguably has a forced outage when the wind does not blow. Therefore, the effective forced outage rate for wind generators may be much higher, from 50% to 80%, when recognizing the variability of wind. In addition, wind's value to the electric system may also vary. The output from some wind generators may have a high correlation with load and thereby can be seen as supplying capacity when it is most needed. In this situation, a wind generating plant should have a relatively high capacity credit. Other factors that determine a wind's capacity credit are provided in Table 8.

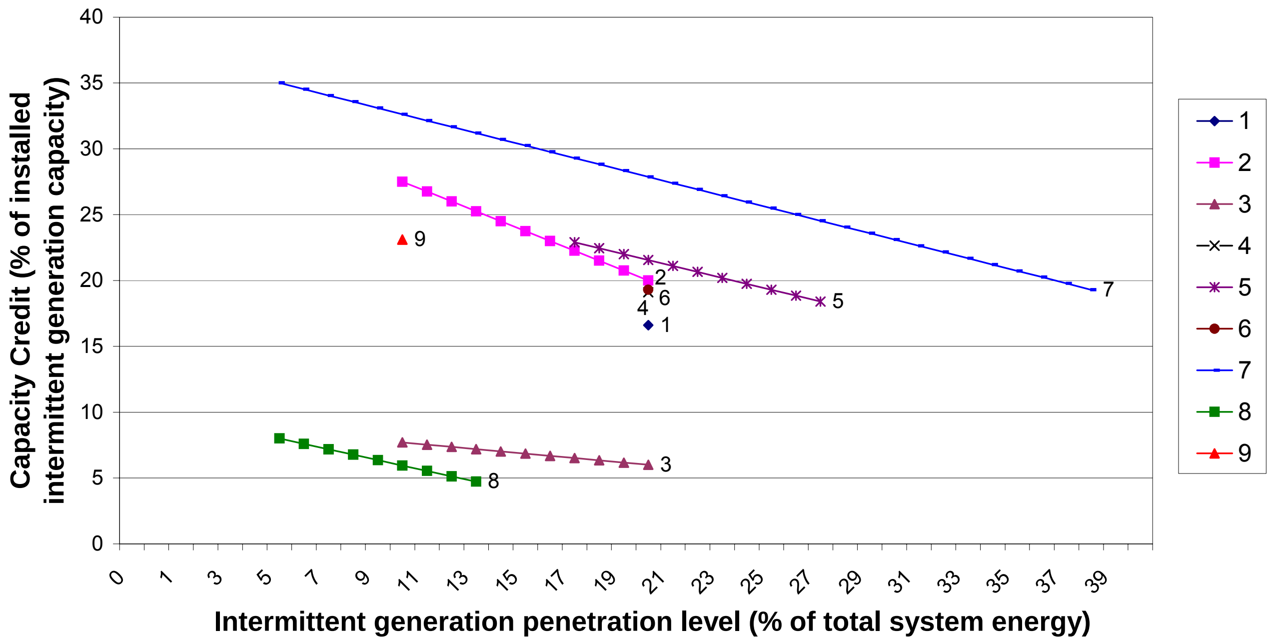
A review of various studies that have estimated the capacity credit of wind power in Europe determined that wind has a capacity credit greater than zero, and also that the capacity credit decreases as the level of wind generation rises. These findings are illustrated in Figure 4.

Table 8. Factors positively and negatively affecting the capacity credit of wind power

Higher capacity credit	Lower capacity credit
Low penetration of wind power	High penetration of wind
Higher average wind speed, high wind season when demand peaks.	Lower average wind speeds
Lower degree of system security	High system degree of security
Higher wind power plant (aggregated) load factor (determined by wind climate and plant efficiency)	Lower aggregated capacity factor or wind power
Demand and wind are correlated	Demand and wind uncorrelated
Low correlation of wind speeds at the wind farm sites, (often related to large size area considered)	Higher correlation of wind speeds at wind farm sites, smaller areas considered
Good wind power exchange through interconnection	Poor wind power exchange between systems

Source: Van Hulle, Fran. 2005*. Large Scale Integration of Wind Energy in the European Power Supply*. Brussels, Belgium: European Wind Energy Association. Available at http://www.ewea.org/fileadmin/ewea_documents/documents/publications/grid/051215_Grid_report.pdf.

Capacity credit studies for wind in the United States have not generally measured the capacity credit of wind versus the market penetration of wind but have focused more on the methods and mechanics of determining the capacity credit for wind. A variety of approaches have been used in the United States for determining the capacity credit of wind, ranging from determining the equivalent load-carrying capability of wind; using a proxy value; or measuring the capacity factor of wind during peak demand hours (Milligan and Porter 2005). Table 9 presents the various methods in the United States for determining the capacity credit of wind.



	Country	Comments	Reference
1	Ireland	Estimate of capacity credit values for an island system	Watson 2001
2	UK	Estimates based on analysis from a three different sources, Central Electricity Generating Board, National Grid, and System Costs of Additional Renewables (SCAR Report)	Mott MacDonald 2003.
3	Germany	DENA project steering group	DENA.
4	UK	Examines the CEGB and SCAR reports and adjusts them for greater penetrations of wind	Dale et al., 2003.
5	UK	Based on modeling	Ilex and Strbac, 2002.
6	N. Europe	Estimates based on reanalysis data collected from operating wind facilities	Giebel, 2000
7	UK	Early assessment of capacity of wind projects in the UK	Grubb 1991
8	Germany	E. On Netz	E.On Netz 2005
9	UK	Study Commissioned by UK Government	Sinden 2005

Figure 4: Capacity credit values

Source: Adapted from Gross, Robert; Heptonstall, Philip; Anderson, Dennis; Green, Tim; Leach, Matthew; and Skea, Jim. (2006). *The Costs and Impacts of Intermittency*. London: United Kingdom Energy Research Center. Available at http://www.ukerc.ac.uk/content/view/258/852. See Reference section for details.

Table 9. Examples of wind capacity credit methods in the United States

Region/Utility	Method	Note
CA/CEC	ELCC	Rank bid evaluations for RPS (low 20s)
PJM	Peak Period	Jun-Aug HE 3 p.m.-7 p.m., capacity factor using 3-year rolling average (20%, fold in actual data when available)
ERCOT	10%	May change to capacity factor, 4 p.m.-6 p.m., Jul (2.8%)
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26-34%)
GE/NYSERDA	ELCC	Offshore/onshore (40%/10%)
CO PUC/Xcel	ELCC	PUC decision (30%) and Current Enernex study possible follow-on, Xcel using MAPP approach (10%) in internal work
RMATS	Rule of thumb	20% all sites in RMATS
PacifiCorp	ELCC	Sequential Monte Carlo (20%)
MAPP	Peak Period	Monthly 4-hour window, median
PGE		33% (method not stated)
Idaho Power	Peak Period	4 p.m.-8 p.m. capacity factor during July (5%)
PSE and Avista	Peak Period	PSE will revisit the issue (lesser of 20% or 2/3 Jan C.F.)
SPP	Peak Period	Top 10% loads/month; 85th percentile

Source: Milligan, Michael, and Kevin Porter (2005). *Determining the Capacity Value of Wind: A Survey of Methods and Implementation*. Golden, CO: National Renewable Energy Laboratory. Available at www.nrel.gov/docs/fy05osti/38062.pdf.

3.3 Implications for California

The CAISO implemented its wind forecasting program, discussed later in this report, in large part because of concerns that the imbalance penalties present in California's 10-minute scheduling protocols would simply make it impossible for new wind projects to be developed in the state. In 2008, the CAISO is scheduled to launch a redesign market based on locational-based marginal pricing (LMP) that is in place in the Midwest ISO, the New York ISO, the New England ISO, and PJM. The market design will allow scheduling coordinators to submit unbalanced bids between generation and load, and is intended to result in deep day-ahead and hour-ahead markets that could more easily integrate variable renewable energy technologies such as wind and solar.

Concerning capacity value, the Energy Commission issued a report in June 2006 that, among other things, estimated the capacity value of renewable energy technologies using the equivalent load carrying capability (ELCC) method. Using a medium-sized gas plant as a benchmark unit, the report found that wind values ranged from 24% to 39% of nameplate capacity, while solar ranged from 79% to 83% of nameplate capacity. Table 10 presents these results. Because of data inconsistencies in the nameplate capacities, the results in Table 10 are represented relative to both reported nameplate capacity and annual peak generation (Shiu et al. 2006).

Table 10. Estimated capacity credit of various renewable energy technologies as compared to a medium-sized gas plant

Resource	Capacity Credit					
	2002		2003		2004	
	ELCC relative to annual peak generation	ELCC relative to reported nameplate capacity	ELCC relative to annual peak generation	ELCC relative to reported nameplate capacity	ELCC relative to annual peak generation	ELCC relative to reported nameplate capacity
Medium Gas	100%	100%	100%	100%	100%	100%
Biomass	98%	98%	98%	98%	98%	98%
Geothermal (north)	108%	108%	109%	109%	109%	109%
Geothermal (south)	109%	109%	109%	109%	109%	109%
Solar	82%	88%	68%	83%	75%	79%
Wind (Northern Cal)	33%	24%	37%	25%	44%	30%
Wind (San Gorgonio)	42%	39%	28%	24%	27%	25%
Wind (Tehachapi)	29%	26%	34%	29%	29%	25%

Source: Shiu, Henry; Milligan, Michael; Kirby, Brendan; Jackson, Kevin. June 2006. *California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis: Multi-Year Analysis Results and Recommendations*. California Energy Commission Consultant Report. Available at http://www.energy.ca.gov/2006publications/CEC-500-2006-064/CEC-500-2006-064.PDF.

4.0 Operational Issues to Date

TSOs have reported various operational issues with wind generation, such as minimum load, high ramp rates, overflow on transmission interconnections and impacts on other generating units and transmission lines. These are discussed below.

4.1 Minimum Load

Defined simply, minimum load is the smallest amount of load on the system during a defined period of time. Minimum load may have different properties. An economic minimum load is when economic generation is curtailed, or when some operational costs are realized to curtail some generation for short periods. A physical minimum load is when total generation is decreased to minimum production, and further reductions in generation will require the removal of some generation from operation.

Denmark's wind integration efforts are aided considerably by the extensive interconnections the country has with its neighbors. All told, Denmark has interconnections to neighboring countries of about 3,000 MW. Even with those inter-ties, hourly wind production in Denmark at times can exceed 100% of load. In these cases, Energinet dK must export the wind generation, or curtail it. Current market rules in Nordpool also do not permit prices to be negative which would provide a useful price signal to generators (International Energy Agency 2005a).

During these times, wind may lower the market price in Western Denmark, sometimes as low as zero for a number of hours. Zero prices occurred for 84 hours in Western Denmark in 2003 (Eltra 2004a). Such a situation can occur even if generation is exported but supply is still more than demand. Effectively, Western Denmark is separated from the rest of Nordpool and constitutes a separate pricing area. Conventional power plants have to reduce their production until the supply and demand balance is restored (Ackerman & Morthorst 2005). Overall, though, one preliminary study determined that consumers in Western Denmark save €60 to €100 million in 2005 from wind displacing fossil fuel plants and lowering market prices (Moller 2006a).

A New Zealand wind integration study used minimum load to determine how much wind could be accommodated on its system. A HVDC line essentially separates New Zealand into two electricity markets, North and South. The study determined minimum load was 1,550 MW in the North and 1,180 MW in the South. After netting out regulation (100 MW), instantaneous reserves (basically spinning reserves: 50 MW) and the marginal generating plant for load following (100 MW), the study determined that up to 1,300 MW of wind could be incorporated in the North and 930 MW in the South, or 2,230 MW in total. That would roughly result in a 35% market penetration for wind, if realized. That could drop significantly if wind projects are concentrated as opposed to dispersed across the country (Energy Link Ltd. 2005).

GE's wind integration study for NYSERDA determined that minimum load is not a concern with regards to wind integration in the New York ISO. New York is an energy importer without wind and remains an importer with wind for all but 25 hours a year, according to GE's wind forecasting case. Only in a case without wind forecasting did energy exports out of New York rise to 100 hours. While units in GE's model were still assumed to be running above their operating minimum points in their model, GE said their assumption that neighboring control areas could absorb the excess wind energy might not be supportable, particularly if those control areas have also incorporated large amounts of wind (Piwko et al. 2005).

There are several characteristics of California's electricity system, beyond the incorporation of additional sources of variable renewables, that may contribute to problems of minimum load. These include:

- "must-run" qualifying facility contracts under PURPA
- increased procurement of combined cycle natural gas projects that operate baseload and around the clock (Dyer et al. 2005).

The CAISO noted that minimum load conditions can be exacerbated in April and May when hydro generation, considered "must-take," surges because of run-off from melting snow and when wind generation correspondingly is at high levels as well (Makarov and Hawkins 2005).

In the IAP, production cost modeling will be used to identify whether minimum load will become a concern as higher levels of variable renewable energy generation. If minimum load issues are identified, the IAP will recommend potential operation and mitigation strategies.

4.2 Ramping

Data from various studies suggest that wind will ramp up and down within ±10% of capacity much of the time over an hour. However, at times wind generation can ramp up and down quite quickly. The variations in wind output are the greatest between 25% and 75% of a wind plant's rated capacity, as the slope of the wind power curve is the steepest. The biggest observed variations in wind output are storm-driven, as wind turbines reach their maximum output and reduce output rapidly after the storm passes through (Holttinen 2004).

Hourly wind variations can be less pronounced, especially if the wind projects are spread out geographically with power output aggregated within the system. As an example, a single wind project can exhibit significant hour-to-hour power swings, but the variability decreases with geographic diversity. One review, for instance, found the maximum hourly variation of 350 MW of aggregated wind projects in Germany did not exceed 20% (Van Hulle 2005). A simulation of wind power in the Nordic countries determined that the largest hourly variations are plus or minus 30% of capacity in a region the size of Western or Eastern Denmark; about plus or minus 20% of capacity when the area is 400 x 400 km^2, such as Germany, Denmark, Finland, or the state of Iowa, and plus or minus 10% in larger areas encompassing multiple countries, such as the Nordic region (Holttinen 2005a). In the Nordic countries, the wind power simulation suggested that hourly changes from wind power are within ±5% 91-94% of the time and between ±10% of capacity 99% of the time. The maximum hourly step changes are ±20% of installed capacity for one country, although the simulation determined it is somewhat higher for Denmark (Holttinen 2004). The variations are more over a four-hour period, with the maximum at ±50% in the Nordic countries (Holttinen 2005a).

It is important to keep in mind that the grid remains reliable and kept in balance and not to focus exclusively on load variability or wind ramping. That said, if necessary, handling wind ramping could take multiple approaches.

- One approach is to understand how large the variability can be, determine whether there are system impacts, and assess whether that variability can be managed with existing system resources via sufficient dispatchable capacity to ramp up and down opposite of changes in wind power, and sufficient regulation or load following to maintain interconnections and system performance within acceptable limits.
- A second approach is to manage variability through ramp rate limits, power limits or curtailments, or using wind forecasting to predict variability and having available system resources to manage the variability (Kehler et al. 2005).
- Another approach is for multiple control areas to cooperate and undertake such actions as sharing reserves or energy imbalances.

Ramping events will be of more concern to small grids, or grids with few external interconnections, or grids with a large concentration of wind projects in one region. Under these circumstances, grids are unlikely to have the deep stack of generating resources, access to balancing markets or the interconnections to other regions or the geographic diversity of wind resources to help manage wind ramping events. Examples of this include the following:

- For its 204 MW wind project, Public Service of New Mexico (PNM) has reported ramps of up to 50 MW in 1 minute; up to 100 MW in 10 minutes, and up to 200 MW in 30 minutes. Because of high natural gas prices, PNM is using older coal units that ramp at 4 to 8 MW per minute to follow the wind generation instead of natural gas units. PNM has not had success in finding balancing supplies in the market (Ellis 2005).
- In its wind integration studies using power simulation models, the Alberta Electric System Operator (AESO) found that while wind output is random over long periods, wind generation could show persistent ramping over short periods. At 225 MW of wind capacity in Alberta, AESO determined that average ramping rates stayed within ±300 MW/hour, but at higher wind penetration levels, larger and more persistent wind ramping rates were found. AESO is a heavily thermal-based system and is relatively self-contained, with a single synchronous connection to Western Canada and the United States (a 500 kV line), heightening variable renewable energy integration challenges (Kehler et al. 2005).
- Transpower, the New Zealand grid operator, reviewed the first two months' operations of two wind projects with a total capacity of 164 MW. Transpower noted that the combined wind output increased by more than 100 MW in a five-minute dispatch period, and that there were two occasions when the combined output increased from near zero to 150 MW in 15 minutes. Transpower has a single HDVC line that connects the northern and southern parts of New Zealand (Energy Link Ltd. 2005).

These grid operators face challenges from wind ramps, and with variable renewable energy integration in general, because of some or all of the following factors: inflexible fuel mix; small control area; lack of a balancing market; and lack (or inadequate amount) of interconnections with other entities. For these reasons, it is not surprising that ramp rate limits on wind have been proposed by grid operators that have some or all of these factors. Examples include the following:

- EirGrid in Ireland that limits the positive ramp rate to 1-30 MW per minute.
- Scotland where the positive ramp rate is limited to 1-10 MW per minute, depending on the capacity of the wind project, and the downward ramp rate to 3.3% of power output per minute.
- AESO has proposed to limit system-wide ramp rates for wind projects to 4 MW per minute and, at least temporarily, overall wind penetration to 900 MW (AESO 2006).

An example where the TSOs limit the positive ramp rate of wind turbines to 10% of rated power per minute may be found in Germany. Other provisions on active power changes are discussed in the grid code section later in this paper.

An example of a wind integration study for a large control area with a relatively deep resource stack is General Electric's wind integration study for NYSERDA. The simulation examined the potential impacts of 10% wind (3,300 MW) on the New York grid. GE determined that the hourly changes in wind generation were generally within +/- 600 MW, with the extreme values less than 1,200 MW (see Figure 5).

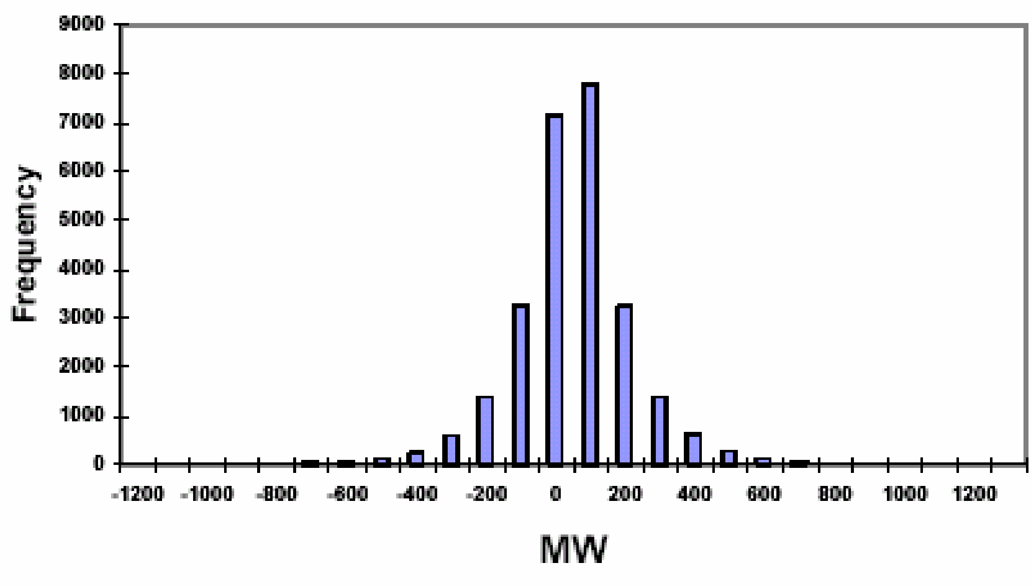


Figure 5: Simulated hourly wind generation changes in New York, 2001–03

Source: Piwko, Richard, et al. 2005. *The Effects of Integrating Wind Power on Transmission System Planning, Reliability and Operations: Report on Phase 2*. New York State Energy Research Development Authority. Available at http://www.nyserda.org/publications/wind_integration_report.pdf.

The GE wind integration study for NYSERDA also discusses the interaction of wind and load ramping. In New York, wind generation has a tendency to drop off during the morning load rise, potentially adding to the ramping requirements. GE determined that without wind, 31% of the sample summer hours have ramp rise rates +/- 2,000 MW/hr, with the worst single hour rising 2,575 MW. With wind, this increases to 34% of hours with rise rates +/- 2,000 MW/hr, and a worst single hourly rise of 2,756 MW. GE found similar trends during winter periods, with the number of hours with +/- 2,000 MW/hr increasing from 2% to 4% with wind, and the single worse hour changing from 2,087 MW/hr without wind to 2,497 MW/hr with wind. GE determined that the net impact on load following was within the capability of the New York ISO to meet.

GE suggested that wind generators be incentivized to reduce wind generation when energy spot prices are low or negative, to avoid the possibility of system reliability being threatened by high wind generation tripping off critical baseload generators with long start times. GE also recommended that the New York ISO have the ability to limit or curtail wind generation for system reliability reasons, such as temporary local transmission limitations or if severe weather is expected. The curtailment would be imposed on a project basis, i.e., the wind operator could choose to meet the proposed curtailment through limiting production or by shutting down individual wind turbines, not the entire wind plant (Piwko et al. 2005).

The IAP will assess whether ramping from variable renewable energy generation will be an issue, and if so, whether operational and mitigation strategies may be necessary, or whether California has the ability to manage ramping. California will likely have more ability to manage ramping than some of the examples presented earlier because of the size of the California grid and control area, the extent of California's interconnections with other states, and the depth of California's resource stack.

An Energy Commission consultant report preliminarily examined ramping capability in the CAISO based on publicly available data and determined that the CAISO had sufficient ramping capability to accommodate load variability and the current level of variable renewable energy generation. The ramping capability estimates in the report are probably low, as the data did not include hydro and some cogeneration and natural gas units. Furthermore, the analysis determined that the ramping requirements of variable renewable energy generators appear to be significantly lower than the ramping requirements of load within the CAISO. Thermal ramping capability exceeded load ramping requirements more than 97% of the time in 2002.

The report found that the peak ramp-up requirements for wind generation occurred in May while the peak ramp-down requirements occurred in February. Ramping requirements for wind generation during the summer months were typically less than 7 MW/minute. There were some ramp-up and ramp-down requirements that exceeded 10 MW/minute, as indicated in Figure 6 below (Shiu et al. 2006).

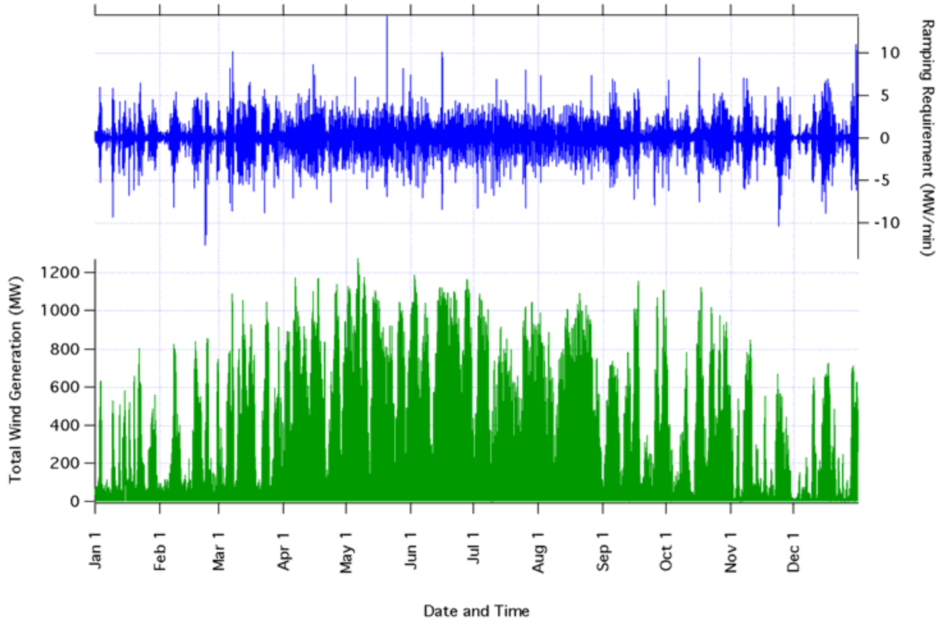


Figure 6: Estimated total wind ramping requirements in California 2002

Source: Shiu, Henry; Milligan, Michael; Kirby, Brendan; Jackson, Kevin. June 2006. *California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis: Multi-Year Analysis Results and Recommendations*. California Energy Commission Consultant Report. Available at http://www.energy.ca.gov/2006publications/CEC-500-2006-064/CEC-500-2006-064.PDF.

Ramping needs for solar generation were also measured for the 350 MW of solar capacity in 2002. Solar generation has a diurnal pattern that necessitates ramping in the morning and evening. Figure 7 provides the solar ramping requirements for 2002.

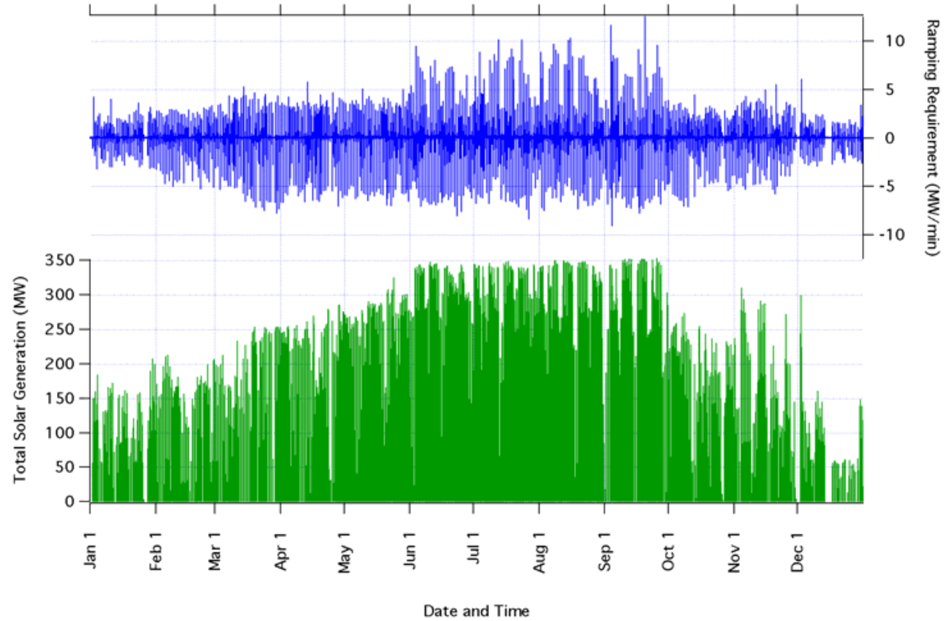


Figure 7: Estimated solar ramping requirements in California - 2002

Source: Shiu, Henry; Milligan, Michael; Kirby, Brendan; Jackson, Kevin. June 2006. *California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis: Multi-Year Analysis Results and Recommendations*. California Energy Commission Consultant Report. Available at http://www.energy.ca.gov/2006publications/CEC-500-2006-064/CEC-500-2006-064.PDF.

4.3 Transmission Rating and Generation Overflow

A 2005 Energy Commission consultant report suggested that the frequency response of generators in California and throughout the WECC have decreased in recent years because of the addition of several generating resources operating at baseload with limited upward capability. That, in turn, could lead to reduced transmission path ratings into California and throughout WECC. That same report found that a significant resource shift to more renewable resources in WECC, without corresponding attention to the thermal capability of generators, voltage support and how generators perform during contingency events, could compound this issue (Dyer et al. 2005). The report concluded that the impact, if any, would arise most likely during non-peak hours.

The dena report perhaps came closest to considering the issues raised in the Energy Commission's consultant report. The dena report determined that several wind projects in Germany were constructed before having to meet grid codes, meaning that the wind projects trip off quickly in response to grid faults. In fact, the dena report determined that reliability criteria would have been violated in 2003 under strong wind conditions with faults in the transmission network. The dropping off of wind turbines in large numbers could contribute to a violation of UCTE reliability rules (i.e., the requirement that 3,000 MW of capacity not be tripped off at once). The dena report found that new wind turbines using more advanced technology (via grid codes), and replacing older turbines over time through repowering would resolve this issue until 2010 in Northwestern Germany, and 2015 in Northeastern Germany. However, reliability issues re-emerge in Northwestern Germany by 2015, as conventional plants begin to shut down because of age or because of the mandatory phasing out of nuclear power.

Under the "Nuclear Exit Law," nuclear power is to be phased out and limited to only 9% of total generation capacity by 2020. Along with expected retirements of older convential units, the dena report predicted the retirement of 40 GW of conventional generation capacity by 2020, out of current installed capacity of 121 GW. In fact, dena could not derive a grid solution for the current system with greater than 20% penetration of renewables (7.5% onshore wind, 5% offshore wind and 7.5% other renewables). Additional support from phase shifters, and the further repowering of wind turbines and additional grid requirements for wind turbines will be necessary, according to dena. This will be the focus of the next phase of dena's study for the period up to 2025 (dena 2005). Among other things, the new dena project will also include an assessment of storage options; sensitivity studies on storm fronts and the impacts on grid reliability; updating concepts in the first dena study on transmitting offshore wind energy to demand centers on land; improving wind and load forecast accuracy; and assessing whether wind can provide reserves. The second phase of the dena study began in May 2006 and is scheduled to take at least 15 months (Ensslin 2006).

The combination of wind from Denmark and Germany can stress the European transmission grid at times, especially during times of high wind production and low demand. Insufficient north-to-south transmission capacity in Germany results in wind generation from Northern Germany, at times, being transmitted to customers in Southern Germany via the transmission networks of the Netherlands, Belgium and France. The system operator in the Netherlands noted that transmission capacity between Germany and the Netherlands, Belgium and France has been seriously congested and system stability threatened at times of high wind output in Germany and Denmark and times of low demand, leading to exports of excess energy (Gul and Stenzel 2005).

5.0 Mitigation and Operating Solutions To Date

As more wind generation comes on-line, several strategies have been proposed and implemented to integrate wind. These include wind forecasting, grid codes, curtailment, wind turbine modeling and verification, demand response, and transmission planning and development. These are discussed below in more detail.

5.1 Wind Forecasting

As wind penetration increases, wind forecasting has become more and more important. In general, wind generation can be predicted more accurately the closer it occurs to actual operation. Wind generation can be predicted with about 90% accuracy one hour ahead, 70% accuracy nine hours ahead, and 50% accuracy 36 hours ahead (Holttinen 2004).

Wind forecasting methods can be roughly categorized into two types: those that apply numerical weather prediction models with equations based on the physics of the atmosphere, and those that apply statistical techniques to produce a wind forecast from available numerical weather prediction models (Table 11). An example of a physical wind forecasting program that uses physical equations is the Prediktor system developed by Riso National Laboratory in Denmark, while the Institut für Solare Energieversorgungstechnik's (ISET) Wind Power Management System (WPMS) in Germany and the Wind Power Prediction Tool (WPPT) developed by Eltra, Elsam, and the Department of Informatics and Mathematical Modeling at the Technical University of Denmark are examples of statistical wind forecasts.

Many wind forecasting systems, including most of those used in the United States, are using both numerical models and advanced statistical methods. For example, the systems from U.S. forecasting providers, including WindLogics, 3Tier Environmental Forecast Group and AWS TrueWind, use learning systems based on Artificial Neural Nets or Support Vector Machines for downscaling from regional physical models to local wind plants. As we will further discuss below, it is also increasing common to use an ensemble of multiple physical weather forecast models and higher-resolution meso-scale models in wind forecasting systems.

Table 11. Overview of operational short-term wind power forecast models in Europe

Prediction Model	Model Developer	Method	Operational Status, Region	Operational Since
Prediktor	RisøNational Laboratory* (DK)	Physical	Spain, Denmark, Ireland, Germany, (USA)	1994
WPPT	IMM, Technical University of Denmark*	Statistical	≈ 2.5 GW, Denmark (East and West)	1994
Previento	University of Oldenburg and Energy & Meteo Systems (DE)	Physical	≈ 12 GW, Germany	2002
AWPPS (More-Care)	Armines/Ecole des Mines de Paris (F)	Statistical, Fuzzy-ANN	Ireland, Crete, Madeira	1998, 2002
RAL (More Care)	RAL (UK)	Statistical	Ireland	--
Sipreólico	University Carlos III, Madrid Red Eléctrica de España	Statistical	≈ 4GW, Spain	2002
LocalPred-RegioPred	CENER (ES)	Physical	Spain	2001
Casandra	Gamesa (ES)	Physical	Spain, Portugal and USA	2003
GH Forecaster	Garrad Hassan (UK)	Physical and Statistical	Spain, Ireland, UK (USA) Australia	2004
eWind	TrueWind (USA)	Physical and Statistical	Spain (represented through Meteosim) and USA	1998
HIRPOM	University College Cork, Ireland Danish Meteorological Institute	Physical	Under development	--
AWPT	ISET (DE)	Statistical, ANN	≈ 15 GW, Germany	2001
AleaWindo	Aleasoft (ES)	Statistical	Spain	2004
Scirocco	Aeolis (NL)	Physical	Netherlands, Spain	2004
Metrological	MBB	Physical	Spain	2004
Meteotemp	No specific model name	Physical	Spain	2004
* Risø and IMM form the Zephyr collaboration.				

Source: Van Hulle, Fran. 2005. *Large Scale Integration of Wind Energy in the European Power Supply.* Brussels, Belgium: European Wind Energy Association. Available at http://www.ewea.org/fileadmin/ewea_documents/documents/publications/grid/051215_Grid_report.pdf.

Statistical wind forecasting tools focus on correlation relationships between weather predictions and wind production. These may employ multivariable statistical methods or learning systems such as neural networks. Statistical wind forecasting can work well if a good weather forecast model is already available, but the performance is also dependent on having access to real-time data from the wind plant. In addition, measured data over several months is also required to train the system before making wind forecast predictions (Ernst 2005a). Physical wind forecasts are based on meteorological depictions of the atmosphere, with numerical weather predictions spatially defined to derive the wind speeds. Projected wind output is determined by modeling expected wind speeds with the power curve of the wind turbines (Focken et al. 2005). Physical equation wind forecasting tools require the exact location and environment of the wind projects and need computational time to transform the wind speed forecasting to wind energy forecasts (Ernst 2005a). They do not necessarily require measured data to produce a forecast, although measured data can be used to improve forecast accuracy (Focken et al. 2005).

Not included in this description of wind forecasts is simple persistence, where current wind generation is forecasted to be the same in future hours. Persistence is sometimes known as "what-you-see-is-what-you-get." That said, because weather patterns may not change from hour-to-hour, persistence in short time frames (less than 6 hours) can be reasonably accurate (Ernst 2005a).

Wind forecasting also differs in each country by how many wind projects are actually measured, and how the measurements are used in determining the wind forecast. In Germany, 36 wind projects in the E. On Netz service territory are monitored, representing 1,330 MW (less than 10% of wind capacity in Germany), and then fed into an algorithm to develop the wind forecast (E. On Netz 2005). More actual wind measurement data can contribute to forecast accuracy, but at a higher cost for data collection. Furthermore, development in Denmark and Germany has not been of several large wind farms but of small collections of turbines, making it more difficult to collect measurement data (Ernst 2005a).

Turning to wind forecasting performance, the mean absolute error (MAE) by installed capacity for wind forecasting in Denmark is typically between 8 and 9%, which is equivalent to a 38% of yearly production miscalculation for market operations (Eriksen and Hilger 2005). A study of one year's worth of data determined that when forecasting 1,900 MW of wind in Denmark six hours ahead, forecast errors were within ±100 MW 61% of the time. Large errors of over 500 MW occurred only about 1% of the time. When forecasting 36 hours ahead, errors were within ± 100 MW 37% of the time, and large errors of over ±500 MW occurred 7% of the time (Holttinen 2004).

In Germany, the root square mean error (RSME) of wind forecasts is 5% to 8% of installed wind capacity with maximum errors ranging from -30% to 40% of installed wind capacity. On a four-hour ahead basis, the RSME is 3.8%, with a maximum error ranging from –28% to 36%. Generally, large errors over 20% occur 3% of the time, while the forecast errors are within 10% about 86% of the time (Ernst 2005b). E. On Netz reported that for 2003, the average negative wind forecasting error was –370 MW and the average positive wind forecasting error was 477 MW. Individual deviations could range from –2,532 MW to 3,999 MW (E. On Netz 2004).

In Spain, the Asociación Empresarial Eólica (AEE), the Spanish wind energy association, is engaged with industry stakeholders and Red Electricia de Espana (REE) in a forecasting exercise to analyze the results of six different wind forecasting models applied to seven wind plants. AEE determined that aggregating multiple wind projects does even out wind imbalances, but found that the mean absolute production error of wind forecasts was 25%. Further, AEE said current wind forecasting tools cannot reduce this error rate without improvements in meteorological input data and real-time wind production and resource data (Ceña 2006b).

As discussed earlier, the variations of wind power generation can be attributed to weather fronts passing through the area, resulting in high winds, and then wind decreasing again after the weather front passes through. That, in turn, can influence the accuracy of wind forecasts. For instance, wind forecasts may predict the occurrence of a storm but the storm may occur a few hours ahead or a few hours behind the wind forecast, resulting in what is called "phase errors" (Van Hulle 2005).

It is difficult to compare wind forecasting in different countries, as the terrain and the wind resources are different. For example, Denmark is relatively flat, aiding wind forecast accuracy, but there are fewer "down" periods for wind and average wind production is higher, leading to higher forecast errors.

Another contributor to wind forecasting errors is the relatively low quality of meteorological data, in part because tracking exact values for regions and time have not been as necessary for other applications (International Energy Agency 2005a). Most forecasting has been focused on other weather items, such as precipitation and temperature, with a lower resolution than is required for wind generation. An accuracy of ± 2-3 meters/second and ± 3-4 hours has generally been enough for general weather forecasts, but can result in large errors for estimating wind power production (Holttinen 2004). Other business and governmental entities are becoming interested in finer, more precise weather forecasting, and that may in turn lead to more improved wind forecasting.

An evaluation of wind forecasting methods, the Anemos project, compared 11 models for six wind projects in four European countries and found the models were site dependent, that not one single model was best at all sites, and the mean error of all models was connected to the complexity of the terrain. Advanced statistical models do well in most cases but require training with half a year of data before performing satisfactorily. Physical tools can have forecasts ready before the wind project is constructed and can benefit from measured data, but require large computational facilities—run as a service by wind forecasting companies (Van Hulle 2005).

As mentioned above, various entities are now using or experimenting with combining statistical and physical techniques, or multiple weather forecasts, in order to improve wind forecasting. In Denmark, Energinet.dk is looking at "ensemble forecasting," i.e., using 25 different wind forecasts and determining an average and distribution for the forecasts. Energinet.dk believes this could improve the forecast accuracy by about 20% (Eriksen and Hilger 2005). The Rheinisch-Westfälisches Elektrizitätswerk Aktiengesellschaft (RWE) TSO in Germany is experimenting with combining different weather forecasting models into a single forecast to minimize wind forecast errors. Different weights will be applied to different wind forecasting approaches, depending on the weather pattern and how effective each wind forecasting method is considered to be with different weather patterns. Early results have proved promising, with the root square mean error being reduced from 5% (best single weather model) to 3.9% using an in individual combination of several models for each weather circumstances (Ernst 2006a). The Anemos project, in addition to comparing different wind forecasting approaches, is testing new wind forecasting methods and programs in seven countries (Kariniotakis 2006).

Several European studies measured the grid and economic impacts of not using wind forecasting. They looked at the impact of allowing wind to simply “show up” in real-time as compared with using a wind forecasting to schedule units. Under this “no wind forecasting” scenario, conventional units are scheduled to run but their output is reduced when wind generation appears, resulting in more part-loaded conventional units and reduced plant efficiencies. Under a wind forecasting scenario, conventional units may not be committed, and those units that are committed run more efficiently (Gross et al. 2006). In the United States, the GE study for New York State determined that using state-of-the-art wind forecasts results in a net benefit of $95 million as compared to letting wind simply show up in real time and backing off conventional generation. A perfect forecast added an additional $25 million in net benefits (Piwko et al. 2005).

Xcel Energy in Minnesota is funding a project to integrate wind forecasting into utility control room operations. The project will assess control room requirements for utility-wide wind forecasting; develop unit commitment and load forecasts; and conduct research and development on defensive operating strategies. Defensive operating strategies include determining the value of additional off-site met towers, high wind forecasting and warning systems, and a rapid update wind forecasting model. Sensitivity analyses will be performed at various wind penetration levels up to 50% of system generation capacity from wind energy (Ahlstrom 2005).

In 2002, the CAISO became the first, and to date, the only regional transmission operator in the United States to use centralized wind forecasting to predict the output of wind generation. The Participating Intermittent Resource Program (PIRP) for wind generators is voluntary. Wind generators that do participate pay the CAISO a $0.10/MWh fee; agree to stay in PIRP for one year; install CAISO telemetry equipment; schedule consistently with the CAISO’s forecast of wind generation and do not make advance energy bids into the California market in order to mitigate concerns that wind generators would try to game the market. The positive and negative imbalances associated with wind power generators are netted out monthly, with the notion that these imbalances will cancel each other out over time.

AWS TrueWind provides the MW forecasts to the PIRP scheduling coordinator, including:

- Hour ahead forecasts for each of the next seven hours, by 15 minutes after each hour (Hour ahead is defined as 2 hours and 45 minutes before real-time);
- Next day capacity forecasts for each hour of the next day, submitted by 5:30 a.m.; and

- Extended hourly capacity forecasts for days two, three and four, also delivered by 5:30 a.m. on Thursdays and Fridays and selected days before holidays.

As of the end of 2005, 11 wind projects are in the PIRP program, amounting to 465.34 MW. For the next operating hour forecasts, the mean average error has ranged from 10–14% of installed capacity, and the bias has ranged from 0.2% to 0.9% of monthly production. For the next day forecasts, the mean average error has ranged from 13% to 18% of installed capacity. AWS TrueWind notes that communication problems have resulted in missing data (Zack 2005). The CAISO notes that 11% of the data was either missing or errant (i.e. wind speeds in excess of 200 mph) (Blatchford et al. 2006). The relatively low level of wind participation in PIRP is also of concern, although some of this may be due to the large number of wind generators that are qualifying facilities under the Public Utility Regulatory Policies Act, and by virtue of contract, can rely on the utility power purchasers to handle scheduling. With over 2,000 MW of solar thermal generation proposed in California, it is likely these generators will join the PIRP program as well.

In addition, the ten cent/MWh fee has been insufficient for the CAISO to recover the forecast service provider's fee. Monthly netting of deviations also has been inadequate to cover the CAISO's costs of procuring imbalance energy, and shortfalls are assessed to market participants (including the participating intermittent resources in PIRP) through an assessment on net negative deviations. In all, the CAISO estimated that $2.3 million in PIRP-avoided charges were not being recovered directly from PIRP participants in 2005. The CAISO notes, though, that improvements in wind forecasting methodology and performance may reduce imbalance charges, and that the total benefits and costs of PIRP will change as the amount of generation participating in PIRP grows or as market prices change (California Independent System Operator 2006b).

The CAISO has undertaken an initiative to improve PIRP. Recommendations include temporarily shutting off the bias and assessing the impact on forecast performance and the allocation of costs to PIRP participants, as well as improving the capability to detect and repair poor quality data (Blatchford et al. 2006). In addition, the CAISO has grappled with exports of energy in PIRP, where energy in the PIRP program that is supplemented by imbalance energy is then exported as a firm export outside the CAISO control area (California Independent System Operator 2006b). The California ISO is working with stakeholders to design a solution that would grandfather existing contracts within PIRP and treat exports from PIRP on a comparable basis with other exports from the CAISO (Johnson 2006). In December 2006, FERC approved a CAISO petition to charge an export fee to PIRP facilities that export energy outside of the CAISO control area (Federal Energy Regulatory Commission [FERC] 2006a).

The Energy Commission and the Electric Power Research Institute (EPRI) have teamed in sponsoring wind forecasting projects to improve PIRP. One project focused on designing a zero-to-three-hour five minute forecasting system through using artificial neural networks and wind production time series data. Using 2004 wind production data, AWS TrueWind determined the mean average error ranged from 0.5% of capacity for 5 minutes ahead to 4-6% for three hours ahead. The project also looked at sources of error including varying grid size. A separate project evaluated different forecast methods for day-ahead forecasting, and determined that the ensemble forecasts result in 3-5% lower mean average forecast errors. Results will be implemented in the PIRP program (Zack 2005).

5.2 Grid Codes

As more wind capacity comes on-line in Europe, TSOs have developed reliability standards and requirements for wind turbines sometimes known as "grid codes." Germany introduced their wind grid code in 2003, followed by Denmark's TSOs in late 2004. Britain, Ireland and the United States have since followed with wind grid codes issued in 2005, and Spain in 2006.

The intent of grid codes is to ensure that wind projects do not negatively impact reliability. A large amount of wind capacity tripping off-line in response to a grid disturbance could lead to a fall in voltage and/or frequency. That, in turn, could contribute to other generators tripping off the grid and could result in not having enough generation to meet load. In areas with large amounts of wind such as Germany, the tripping of a significant amount of wind could result in the loss of more than 3,000 MW of wind generation, which would therefore violate UCTE reliability rules. In Spain, wind outages of up to 500 MW may occur from faults in the transmission or distribution network. The United Kingdom sets its contingency planning for the maximum and instant loss of 1,320 MW. That country found that the early non-synchronous wind turbines would trip at voltage drops of 80% of nominal voltage, possibly resulting in the loss of 1,320 MW of conventional generation if several adjacent wind projects tripped off-line at once (Johnson and Tleis 2005).

Developing grid codes can take some time, and in some instances, wind turbine development can proceed rapidly while grid codes are under deliberation. Although Germany adopted grid code requirements in 2001 and 2003, for instance, wind capacity increased significantly in Germany but without meeting current grid code provisions such as fault ride-through requirements. (Eriksen et al. 2005).

As grid codes for wind proliferate, some have called for a uniform grid code for wind. UCTE, for instance, has called for a harmonized international grid code for wind turbines (UCTE 2005a). Meanwhile, some wind turbine manufacturers have expressed frustration with the divergent grid codes, contending that wind turbines will be designed for the largest markets and for the strictest grid code requirements, adding to costs. Some estimate that large wind turbine manufacturers have four-to-five staff members to monitor grid codes, and that the fault ride-through provisions can increase the total turbine costs by up to 5% (Matevosyan et al. 2005). The European Wind Energy Association believes it would be difficult to design a Europe-wide grid code for wind because of differences in the energy mix, the strength of the interconnections, the size of the grid, and the wind penetration levels for each country. Each of these factors affects the technical requirements for a grid code for wind (Van Hulle 2005).

The grid codes have emerged on a transmission operator-by-transmission operator basis, and differences between the grid codes have naturally resulted. To date, grid codes have featured these major themes:

- Requiring wind turbines to ride through grid faults
- Increase or decrease power generation at the TSO's request; supply reactive power
- Adjust power generation in response to frequency changes
- Control or limit ramping increases

Fault Ride-Through Requirement: Generally, fault ride-through requirements specify that wind generators must stay connected for a period of time when faults occur on the transmission system and voltage drops (Van Hulle 2005). All wind grid codes have some type of fault ride-through requirement, although these requirements differ by country, and even by TSO. For example, Denmark requires wind turbines to stay on-line for 100 milliseconds from a voltage drop to 25% of nominal network voltage, while Ireland requires wind turbines to stay connected for 625 milliseconds from a voltage drop to 15% of nominal network voltage (see Table 12) (Milborrow 2005b). A stricter example is the United Kingdom's grid code that requires wind generators to stay interconnected at voltage drops down to zero for 140 milliseconds (Massy 2005). A WECC task force is considering possible changes to WECC's current low-voltage ride-through standard to lower the minimum voltage tolerance period to zero at the point of interconnection for 12 cycles (about 1/5 of a second) (Ellis 2006).

Table 12. Examples of wind grid codes

Grid Code	Fault Duration (Milliseconds)	Voltage Level During Fault (% Nominal)	Voltage Recovery (Milliseconds)
Denmark	100	25	1000
Germany (E. On)	150	0	1500
Ireland (Eir Grid)	625	15	3000
UK (NGT)	140	0	1200
Spain	500	20	1000
United States	150	0*	NA
* As of 2008. For 2007 and for normally cleared three-phase faults, wind turbines must be able to ride through voltages down to 15% at the point of interconnection for 150 milliseconds.			

Source: Milborrow, David. 2005b. "Going Mainstream at the Grid Face." ***Windpower Monthly*****, September 2005, p. 49. Reproduced by permission. United States provisions drawn from Federal Energy Regulatory Commission. December 12, 2005. Order No. 661-A: Interconnection for Wind Energy.**

Fault-ride through requirements may also apply differently by TSO, depending on the provisions. The United Kingdom's grid code applies to large and medium wind projects with a siting permit and all wind projects connected to the transmission grid. In England and Wales, this translates to large wind projects over 100 MW or medium projects between 50 and 100 MW that are interconnected to the transmission network at between 275 kV and 400 kV. It should be noted that smaller wind projects interconnected with the distribution network may have agreements with the NGT grid operator to comply with certain parts of the United Kingdom's grid code. In Scotland, though, large wind plants are defined as over 30 MW, with medium-sized plants are considered any wind plant over 5 MW, and the transmission network begins at

132 kV. Therefore, the United Kingdom's grid code will likely apply to more wind generators in Scotland than in the rest of the United Kingdom (Massy 2005).

The interplay with fault ride-through requirements and interconnecting to the distribution grid, rather the transmission grid, can also be challenging. Wind projects in New Zealand will mostly be connected to the distribution grid instead of the transmission grid. While it is clear that wind projects should stay connected if there is a fault on the transmission grid, if there is a fault on the distribution grid and the circuit breaker that connects the distribution feeder to the transmission grid opens, the wind project should perhaps trip offline to prevent creating an "islanded" network. To handle both situations, wind projects would need voltage ride-through capability and anti-islanding protection (Energy Link Ltd. 2005).

Frequency Response: The frequency in a power system reflects the balance or imbalance between production and consumption. The system frequency in Europe is maintained at or around 50 Hz, while it is maintained at 60 Hz in the United States. In Europe, primary control units with frequency-detecting equipment will increase or decrease generation, ranging from one to thirty seconds, to maintain frequency. Secondary control units will be triggered within 10–15 minutes to relieve primary control units. Automatic generation control is used on secondary control units in some countries, while the system operator may use manual control in other countries.

EirGrid in Ireland requires wind projects to provide primary frequency control of 3-5% of power output and to provide secondary frequency control if called upon. In Denmark, Energinet dk requires wind projects to provide secondary frequency control after a system fault, or if part of the grid is isolated (also called "islanded") from the disconnection of several large transmission lines (Matevosyan et al. 2005). The United Kingdom's TSO also requires this capability, and other TSOs will likely require it as wind penetration increases, particularly for low-demand, high-wind situations (Van Hulle 2005). To meet this requirement, wind turbines operate at less than full output such that blade pitch can be adjusted to increase generation when called upon. Some assert that the financial consequences to a wind generator for holding back output to meet frequency response requirements are too severe, and conventional generators can meet this requirement more easily and at a lower cost (Milborrow 2005b). However, in the United Kingdom, wind generators can specify the bid price at which they are willing to be "de-loaded" (generate at less than full output). Furthermore, the wind generator will receive two payments for supplying frequency response (holding and response energy payments) (Johnson and Tleis 2005). Alternatively, wind generators could perhaps purchase frequency control obligation from another generator.

Ramp Rate Limitations: Some TSOs are restricting rapid increases or decreases in ramp rates for wind projects in order to suppress large frequency fluctuations that may result from large wind variations during the start-up and shut-down of wind projects, and to not exceed the operating parameters for generators providing primary or secondary reserves. TSOs in Germany limit the positive ramp rate of wind turbines to 10% of rated power per minute, and EirGrid in Ireland limits the positive ramp rate to 1 to 30 MW per minute. Scotland limits the positive ramp rate for wind turbines to 1 to 10 MW per minute, depending on the capacity of the wind project, and the downward ramp rate to 3.3% of power output per minute. Examples of grid code provisions that limit active power change and ramping are listed in Table 13. Not included in the table is a proposal by the Alberta Electric System Operator to limit ramp rates for wind projects to 4 MW per minute.

Table 13. Power control requirements for wind turbines

Requirement	Source	Country
Active power: 1 min average ≤ production limit + 5% of maximum power of wind farm[a]	Eltra	Denmark
1 min average = ∀5% of rated power of the wind turbine from conditional set point (0-100% of maximum power of wind farm)	Eltra and Elkraft	Denmark
10 min average ≤*k*H registered capacity at any time ≤ registered capacity	E.On Netz, ESB, VDEW	Denmark, Sweden, Germany, Ireland
Active power change:		
Reduction to <20% of maximum power (by individual control of each wind turbine) when demanded: in 2s (Eltra); in 5 sec (SvK)	Eltra, SvK	Denmark, Sweden
Power change from any operating point to a set point defined by E. ON	E.On Netz	Germany
Power reduction of a minimum of 10% of registered capacity per minute	Eltra and Elkraft	Denmark
Power increase ≤10% of registered capacity per minute Adjustable in the range of 10-100% of rated power per minute		
In any 15-minute period, active power change is limited to: 5% rated power of wind farm per min (P_{WF} < 100 MW) 4% rated power of wind farm per min (P_{WF} < 200 MW) 2% rated power of wind farm per min (P_{WF} < 200 MW)	EirGrid	Ireland
Specific reduction must be possible; reduction order comes from system operator	SvK	Sweden
Active power change is limited to: 60 MW per hour, 10 MW over 10 min, 3 MW over 1 min (for P_{WF} < 50 MW); 4H registered capacity per hour, registered capacity/1.5 over 10 min, registered capacity/5 over 1 min (for 15 MW < P_{WF} < 150 MW)	Scotland	Scotland
600 MW per hour, 100 MW over 10 min, 30 MW over 1 min (P_{WF} < 150 MW) (may be exceeded at $f \neq 50$ Hz if farm provides frequency control)		
Startup:		
Wind farm shall contain a signal clarifying the cause of preceding wind farm shutdown. This signal should be a part of the logic managing startup of wind turbines for operation	Eltra	Denmark
Has to comply with requirements regarding active power change	Scotland, E. ON DEFU 111, AMP, Sintef, VDEW Scotland, Eltra, E. ON	England, German, Sweden, Norway
Has to comply with requirements regarding active power change	Scotland, E. ON DEFU 111, AMP, Sintef, VDEW Scotland, Eltra, E. ON	England, German, Sweden, Norway
Shutdown:		
High wind speed must not cause simultaneous stop of all wind turbines	Eltra, SvK	Denmark, Sweden
No more than 2% of registered capacity may be tripped. Phased reduction of output over 30 min period	Scotland	Scotland
Has to comply with requirements regarding active power change	Scotland	Scotland
Has to comply with requirement regarding voltage quality	DEFU 111, AMP, VDEW	Germany, Scotland, Denmark

Notes to Table 13:

[a] The production limit is an external signal deducted from the local values of, for example, frequency and/or voltage.

PWF = rated power of wind farm; DEFU = Research Institute of Danish Electric Utilities; AMP = Abbreviation of a report, in Swedish, of Connecting Smaller Power Plants to the Electrical Network; VDEW = German Electricity Association; SvK = Svenska Kraftnat (the Swedish TSO); Sintef = A Norwegian research institute

Source: Matevosyan, Julija; Ackerman, Thomas; and Bolik, Sigrid M. "Technical Regulations for the Interconnection of Wind Farms to the Power System," Table 7.1, in T. Ackerman (Ed.), *Wind Power in Power Systems* (pp. 115-142). England: John Wiley and Sons, Ltd. Reproduced by permission.

Frequency Range: In recent years, TSOs are requiring wind projects to stay on-line during a wider frequency band, in contrast to past years when grid operators wanted wind turbines to drop off in case of frequency deviations. Figure 8 provides examples of frequency control requirements in certain countries.

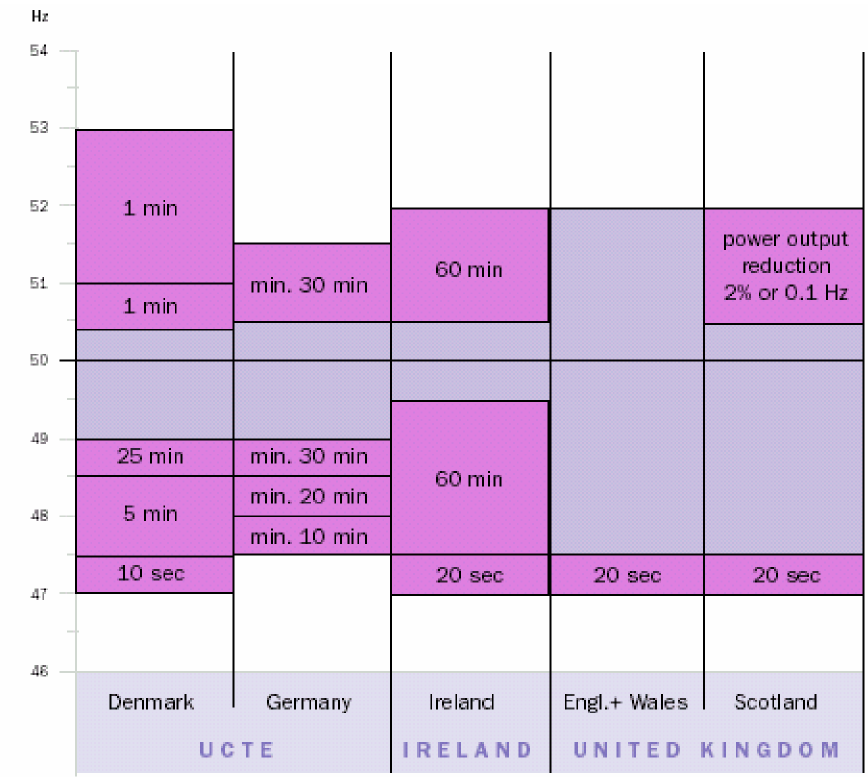


Figure 8: Frequency control requirements by selected country

Source: Van Hulle, Fran. 2005. *Large Scale Integration of Wind Energy in the European Power Supply*. Brussels, Belgium: European Wind Energy Association. Available at http://www.ewea.org/fileadmin/ewea_documents/documents/publications/grid/051215_Grid_report.pdf.

Voltage Control: Grid codes generally require wind turbines to operate continuously at rated output in normal voltage ranges and to stay on-line during voltage changes within a specified range. Wind turbines are also expected to supply reactive power, ranging from 0.925 (leading) to 0.85 (lagging) (Van Hulle 2005). Newer variable speed generators, such as double-fed induction generators, can allow wind turbines to provide reactive power (Milborrow 2005b).

Turning to particular countries, E. On Netz in Germany requires wind turbines to continue to supply reactive power for up to three seconds after a voltage drop, a turn-about from previous practice of requiring wind turbines to disconnect during network voltage disturbances (Knight 2005). Wind projects 20 MW and higher in Sweden have to maintain automatic regulation of reactive power, with voltage within plus or minus 10% of nominal operating voltage. That same requirement is in place for wind turbines in Norway interconnected at 35 kV or higher (Matevosyan et al. 2005). A proposal in Spain will require wind turbines to stop drawing reactive power within 100 milliseconds of a drop in voltage and provide reactive power within 150 milliseconds of grid recovery. Wind projects that meet Spain's grid code would receive a 5% production bonus for their output (McGovern 2004).

5.2 Wind Turbine Modeling and Verification

A common issue in the United States and around the world is the need to improve the modeling of wind projects for determining the potential impacts on system reliability during the process of evaluating interconnection applications from wind generators. In the United States, most of the wind development until 10 years ago occurred in California. Development in the Altamont Pass took place on a reasonably strong part of the grid, perhaps decreasing the need for grid-friendly wind turbines and features. More issues occurred with wind development in Southern California with voltage problems and a somewhat weak transmission network, but the knowledge of these problems and potential solutions stayed within a small community.

As wind development spread beyond California in the mid-1990s, transmission providers had little knowledge or experience with wind technology. As a result, early studies of the grid reliability impacts of wind facilities were conducted with rough models and several simplifying assumptions. Problems included:

- Use of induction machine models from reliability models to model wind turbines, even if more advanced wind turbines with improved grid features were to be deployed at the proposed project.
- Development of wind projects in relatively weak areas of the bulk power network.
- Disperse (dozens-to-hundreds) wind turbines representing a wind project, as compared to a single or small group of units for a conventional generating plant. With the increasing size of the wind projects and the lack of available models, deriving a satisfactory interconnection and determining how much transmission capacity was necessary to move wind power to load centers proved challenging.
- The pace of wind project development exceeding the time needed to reinforce the bulk power network, leading to delays in wind project development or temporary constraints on wind project operations (Zavadil et al. 2005). The WECC Wind Generator Modeling Group is working on wind turbine generator models, and it is anticipated that a suite of four such models will soon be available (Ellis 2006).

In addition, although there is significant activity concerning model development for interconnecting wind turbines, there has not been significant field testing of models. Ideally, model simulations would be verified via field testing to show that the dynamics of a model truly represent the electrical network performance of a facility and its surrounding system. However, field testing can be a costly and problematic endeavor that requires creating a system disturbance or fault from which the results can be measured. Purposely creating a fault in the electric grid is not a trivial event, subsequently field-testing modeling results for accuracy is not generally done. The exception is the dynamic performance testing conducted at the Woolnorth Wind Farm, a Hydro Tasmania facility located within the Tasmanian Power System grid in the island state of Tasmania near Australia.

The Tasmania power system has 2,500 MW of generating capacity with a system peak demand of 1,700 MW. While it was previously an isolated system, Tasmania was interconnected with the mainland system via a monopolar HVDV line, "Basslink," which commenced commercial operation in April 2006. Extremely good wind conditions and the availability of hydroelectric resources make Tasmania an attractive location for wind power. The Woolnorth Wind Farm was the first wind farm in Tasmania, a 65 MW facility (37 Vestas V66 turbines each rated at 1.75 MW) connected to the 110 kV transmission system with a relatively weak connection point (450 MVA) at Smithton.

The decision to conduct a system performance test on Woolnorth was made based on the use of new technology (variable speed generators) and the limited amount of data available on the equipment's impact on the power system. The tests were conducted to verify compliance with fault ride through requirements and to measure the results of system frequency disturbances and active control capabilities of the wind farm. The tests involved the application of external disturbances that were used to assess the performance of the variable speed generator, the need for ancillary services, and the accuracy of wind farm generator models and their assumptions.

The performance predicted by the models was generally borne out in the tests, and the functionality of the wind farm control system was proven. However, other tests may need to be carried out to verify other types of wind turbines and control technologies. In addition, the Vestas wind turbines tested in Tasmania are not available in the United States for patent reasons, and the test results in Tasmania may not be directly transferable to the United States. In any event, a summary of the specific tests and their results are included in Table 14 (Piekutowski et al. 2005).

Transmission operators in Europe have also raised concerns about insufficient dynamic models, as well as the variety of different turbine models that contribute to the difficulty of modeling wind turbines for interconnection to the grid. Manufacturer-specific models are becoming more available, and European transmission operators have developed and validated some detailed dynamic models (Eriksen et al. 2005). Continued growth in wind energy may be conditioned in some countries on not only resolving uncertainties about the grid impacts of wind turbines but also on the availability of analytical tools and models. For example, EirGrid has instituted certification requirements for wind turbine models to be used in system interconnections as part of Ireland's grid code (Zavadil et al. 2005).

Table 14. Summary of performance tests and results for the Woolnorth Wind Farm

Test	Purpose	Outcome
Step Change in Voltage	The ability of the wind farm to keep voltage constant in local load centers	Wind farm power output remained in phase with active power after the step change in voltage. A reduced reactive power contribution from the step change in active power output was observed, but not reflected in simulation models.
Step Change In Wind Turbine MW Set Point (temporarily lowering output to simulate rapid variations in wind creating an increase of active power by 18 MW)	Verify performance of wind farm controller	The increase in real power increases reactive power losses through the wind turbine transformer leading to a decrease in the reactive power at the Woolnorth and Smithton busses.
Transmission Line Switching	Impact on oscillatory stability and damping contribution	Reasonably good match in reactive power, however, simulated tests did not match the measured tests.
Single Phase to Ground Fault 1	Operation of fault ride through capability	The fault was cleared, as expected, in 70ms, however the fault was picked up on the transmission system further down the line, opening a circuit breakers, and raising concerns on islanding.
	Islanding	The detection of islanding conditions was too slow and could lead to an out of phase synchronization
Single Phase to Ground Fault 2 (repeat test)	Measure impacts at three distinct locations: point of interconnection (110kV), wind farm distribution (22kV), and select wind turbines	The fault cleared in 66 ms. One turbine with advanced wind option technologies tripped and several other turbines without the advanced technology also tripped
Under Frequency Test	Evaluated the results of tripping a neighboring hydroelectric facility offline – tests frequency control	Confirmed that the turbines do not contribute an inertial response after a frequency disturbance.

Source: Piekutowski, Marian; Field, Tony; Ho, Sam; Martinez, Antonio; Steel, Marcus; Clark, Stephen; Bola, Satendra; Jorgensen, Henrik Kanstrup; and Obad, Mujo. "Dynamic Performance Testing of Woolnorth Wind Farm." Presented before the Fifth International Workshop on Large-Scale Integration of Wind Power and Transmission Networks for Offshore Wind Farms, April 7-8, 2005, Glasgow, Scotland.

5.4 Demand Response

Demand response may help integrate larger amounts of wind power through moving consumption from when wind production is low to times of higher wind production, such as additional pumping at pumped storage hydro facilities (Strbac 2002). One example researched in Denmark is the use of electricity for district water heating instead of other fuels (Eltra 2004a) when wind production is high and market prices are low.

Participation in demand response programs has been relatively small in Europe. The reasons are unclear, although it may include transaction costs, information barriers, or simply that the marginal value of electricity for consumers is higher than even high market prices for electricity (Gul and Stenzel 2005). One study in Finland, for instance, determined that only one-quarter of all customers responded strongly to variable pricing (Giebel 2005).

Demand response in the United States is also not widespread, although regulatory and industry interest is growing significantly. A FERC survey found that about 200 entities offer some type of demand response program, with most of these consisting of direct load control, interruptible/curtailable programs, and time-of-use rates. About 5% of customers are on some form of time-based or incentive-based demand response program. Overall, the total potential demand response contribution from existing programs is estimated to be 37,500 MW (FERC 2006b) in the U.S.

Shifting demand is cited as one tool to assist with integrating large amounts of wind. For this and other reasons, Nordel requested that each TSO prepare a demand response action plan in 2004. Currently, Norway and Sweden both consider demand and supply sources when contracting for reserves. Eltra in Denmark, before merging with Elkraft to form Energinet dk, launched a demand response action plan to, at least in part, help integrate wind power. The plan included 22 pilot projects to test the viability of demand response, and will be conducted in phases between 2008 and 2010 (Gul and Stenzel 2005). Denmark's extensive ties with Norway, Sweden and Germany suggest that demand response can be acquired through those countries as well, assuming there is available exchange capacity.

In California, the California Public Utilities Commission set targets for utilities to meet 3% of its annual peak demand with demand response, increasing 1% per year to 5% by 2007 (CPUC 2003). California also has implemented a "preferred loading order" for resource procurement consisting of decreasing electricity demand by increasing energy efficiency and demand response, and meeting new generation needs, first with renewable and distributed generation resources, and second with clean fossil-fueled generation (Bender et al. 2005). The CAISO also allows qualifying loads to participate in their replacement reserve and supplemental energy markets (FERC 2006b).

5.5 Storage

A long discussed option is to use various types of storage technologies to help balance aggregate system variability, including wind, load and other generation. California has over 4,000 MW of pumped storage hydro projects, with 2,700 MW in the CAISO control area. These projects offer a natural means of storage, but that resource may not always be available. The pumped storage projects may be utilized for other applications such as flood control, recreation and power generation.

Another option is combining compressed air energy storage (CAES) with variable renewable energy generation. In Iowa, a group of municipal utilities and surrounding states are planning to build a 75-to-150 megawatt wind project paired with CAES, and the Texas State Energy Conservation Office is also considering compressed air energy storage with wind. Still other potential technology options include battery and flywheel technologies (Jones et al. 2005a).

Denmark also has examined whether wind production can be converted to electrolysis for the production of hydrogen, although at least for now, it is believed that there are only a small number of hours where this may be economic (Eltra 2004a). Finally, Elkraft (the TSO for Eastern Denmark prior to its merger with Eltra) financially supported a pilot project testing a 15 kW battery with wind turbines to test battery efficiency, response to the wind turbines, and general system operating conditions (Eltra 2004a).

Energy storage options are beginning to be a part of some new or proposed wind projects. VRB Power recently sold a small energy storage project that can provide 12 MWh (1.5 MW over eight hours) of storage to the planned 32 MW Some Hill wind project in Ireland (Hamilton 2006). In addition, Japan's Agency of Natural Resources and Energy is considering partially subsidizing the costs of energy storage facilities in response to utility concerns about wind's variability (Dahl 2005). Such energy storage options are not inexpensive. The VRB system in Ireland is about $4,000/kW, and Japan's Agency of Natural Resources and Energy estimated energy storage would add 50% to the cost of wind power (Hamilton 2006; Dahl 2005). California utilities and the Commission are beginning to investigate storage at key substations and interconnection points as a way to manage storage integration costs.

5.6 Wind Power Curtailment

Maximum wind production can be several times larger than average production, meaning that at 20% wind penetration by energy, wind production may equal consumer demand for some hours. Curtailment of wind generation may occur if the amount of wind generation at a specific time is more than what the grid can readily take in. Factors that could affect the amount of wind energy that is curtailed are listed below:

- Wind curtailments will occur at lower wind penetrations on grids dominated by thermal or nuclear generation that may not be very flexible, or includes generation affected by policy constraints, such as "must-run" units.
- The correlation between wind generation and demand will also affect whether wind is curtailed or not . Curtailment will be lower if wind generation is associated with electric demand, and conversely, will occur more often if wind generation is high when demand is low.
- The availability of transmission capacity will also affect if wind generation is curtailed. If transmission is available to transmit wind generation to other areas, then curtailment of

wind generation is likely to be less; however, if wind generation is remote from load and transmission is constrained, then wind generation is more likely to be curtailed.

For grids dominated by thermal generation that may not be very flexible, wind curtailments could occur at penetrations as low as 10%. At 20% penetration by wind, upwards of 10% of total wind generation could be curtailed (Holttinen 2004). One study of Sweden determined that over 16% of wind generation could be curtailed at an 11% penetration of wind if the wind generation is located in the north, and there is little or no transmission capacity to transmit the wind energy to the south. Other studies found that in systems with more flexible resources, the level of wind curtailment would be much lower (Gross et al. 2006). Countries with "must-take" requirements in their renewable energy feed-in laws tend to have the toughest grid code provisions with regards to wind curtailment. One example is in curtailing wind production upon the TSO's request, present in the grid codes in Denmark, Germany, Ireland and Spain.

Some wind curtailment has occurred in Western Denmark, and in Northern Germany, wind turbines are curtailed when there is transmission congestion (Gul and Stenzel 2005). In Northern Germany, E. On Netz implemented curtailment policies, or "generation management" as described by E. On Netz, for wind generators in the Schleswig-Holstein region in mid-2003, covering 700 MW (about 1/3 of the wind capacity in that region), and expanding it to Lower Saxony in 2005. E. On Netz divided its grid in Schleswig-Holstein into 10 regions, and they expect Lower Saxony to be divided into 25 regions. If overload conditions are present, E. On Netz identifies the region of concern and sends a signal to wind projects to adjust output accordingly, defining the maximum active output that the region's wind projects can provide to the grid. In 2004, E. On Netz issued such directives in Schleswig-Holstein 17 times, with the duration for each directive ranging from 30 minutes to 12 hours, and wind production being reduced between 0 and 60% (E. On Netz 2005). Until new transmission capacity is added, E. On Netz will not interconnect new wind projects in Schleswig-Holstein unless the wind generators participate in E. On Netz's generation management program (E. On Netz 2004).

Spain has also curtailed wind generation due to local grid limitations. In the past, REE, the grid operator in Spain, curtailed wind output if wind power penetration exceeds 12% of demand. REE derived this penetration level through system studies of the Spanish grid and its international connections, particularly the interconnection to France. Under its interconnection agreements, REE can curtail wind production if system conditions require such action. REE said it would first curtail or disconnect wind projects that did not have fault ride-through capability.

Curtailment was relatively infrequent in Spain up to 2003. One occurrence was in the Galicia region in Northwestern Spain, which has limited connection to the transmission grid and in periods of high rainfall, cannot handle both the hydro and wind generation. Losses for wind operators in that region from curtailment have been up to 12% of annual output. Wind curtailment in 2004 in the rest of Spain occurred generally whenever wind generation exceeded 12% of demand, particularly during valley hours on weekends. In 2005, however, curtailment occurred less frequently. In addition, it appears that REE's limit of 12% wind was relaxed in 2005, as there have been periods of wind penetration considerably higher than 12%–the highest half-hourly penetration has been 24% of total demand (Craig 2006).

A wind integration report done in New Zealand recommended allowing the grid operator to disconnect wind projects remotely or to curtail output in cases of high wind or if there are transmission constraints that affect system security. The New Zealand report also recommended curtailing wind output in dry water years when the HDVC link that connects the north and south parts of the country is used for transmitting power south (Energy Link Ltd. 2005).

In October 2005, Energinet.dk, the new TSO for Denmark, conducted a study of steadily increasing wind scenarios to 100% wind generation to determine, among other things, how much would be curtailed. To keep the study simple, Energinet.dk disregarded international interconnections and CHP generation. At 100% wind, the need for baseload generation falls from 4,000 MW to about 2,000 MW, but the need for peaking units increases from 1,600 MW with an all-thermal system to about 3,000 MW with 100% wind generation. In its simplified scenario, wind generation does not have to be curtailed until wind penetration is at 30% but increases significantly to 8 TWh (about 31% of total wind generation) at 100% wind (Energinet.dk 2005). Energinet.dk assumed that at high wind generation levels, wind production would be curtailed or sold to electric boilers or heat pumps at a below-market rate of €13/MWh (Windpower Monthly 2006). Energinet.dk found additional costs of €6-13/MWh from the higher wind generation, although the TSO cautioned that it did not factor in ancillary service costs, grid stability issues, or transmission capacity in the study (Orths et al. 2006).

5.7 Transmission Planning and Development

The European Union has been moving towards a liberalized electricity market, with the aim of developing a single Internal Electricity Market. EU directive 2003/54/EC, for instance, calls for all non-household electricity customers from July 1, 2004, and all customers from July 1, 2007, to have access to be able to freely negotiate the purchase and sale of electricity. In addition, third party grid access is assured, and transmission and distribution companies must legally unbundle by July 1, 2007.

Wind development in Europe has coincided with the liberalization of electricity markets, leading to more regional power trade and greater use of the transmission system that was developed to serve internal electricity markets, not necessarily to facilitate inter-country trade. Overall, the International Energy Agency predicts that $1.8 trillion of transmission and distribution investments are necessary by 2030 simply to meet demand growth and to upgrade existing assets (Gul and Stenzel 2005). Furthermore, planning for wind generation and planning for transmission often proceed independently, with transmission projects taking up to 10 years to plan and develop. A number of entities are calling for an acceleration of transmission development (Gul and Stenzel 2005; Van Hulle 2005; UCTE 2005a).

As noted earlier, strong grid interconnections have played a part in helping Denmark manage its high level of wind production. In general, though, there is limited interconnection between national and regional electricity markets in Europe, and current trans-country interconnections are heavily loaded (Meeus et al. 2005). Currently, cross-border capacity allocations between countries are determined each year, for peak hours in the winter and in the summer by the

European Transmission System Owners (Wayte et al. 2005). EWEA has called for allocating some of that cross-border capacity to renewable energy to ensure that countries meet their renewable energy goals.

The European Union has two efforts underway that involve, at least in part, planning for transmission and wind energy. The Trans-European Networks for Energy, known as TEN-E, is aimed at improving operation of the European energy markets, reducing isolation of some regions in the European Union, and reinforcing energy supply security. The European Commission is financing the Concerted Action Offshore Energy Wind Development project, or COD, that among other things, is aimed at developing high-voltage transmission links between countries and interconnecting different offshore wind projects and load centers over long distances. Some of the transmission needs identified by either TEN-E or COD include:

- Higher transfer capabilities between Nordel and UCTE;
- Strengthening transmission interconnections into Poland;
- Increasing transmission capabilities between UCTE and Spain, Italy and the Balkan states;
- Reinforcing transmission lines between France, Germany and Belgium, Netherlands and Luxembourg;
- Reinforcing transmission connections from Central and Western Europe to the Balkan states, the Mediterranean countries, and Portugal;
- Increasing transmission capacity between Germany, Austria and Central European countries; and
- Creating a Mediterranean transmission network connecting Southern Europe to Northern Africa and the Near East (Van Hulle 2005).

Increasing cross-border electricity transactions, the interest in developing renewables, and shoring up energy security is prompting consideration of bolstering cross-border transmission capabilities. TEN-E first listed "bottlenecks of common interest" in 1996 and updated it three times by 2003. In 2004, the European Commission, in response to the expansion of the EU, listed nine axes or clusters of priority projects (Meeus et al. 2005).

Others have called for the development of trans-European super grids, covering both offshore and onshore. More aggressively, some advocate for a grid connecting Europe, North Africa and the Middle East (Van Hulle 2005). In May 2006, Airtricity announced its intent to develop a series of high voltage AC/DC network lines to connect several offshore wind projects from the Mediterranean to the North and Baltic Seas. Besides transmitting wind energy, the project is also designed to be a Europe-wide transmission network (Airtricity 2006).

It is well known that California has significant transmission issues, and it will only be briefly discussed here. In 2004, the CAISO incurred congestion and must-run reliability costs of $1 billion. Those costs did not include inter-zonal costs or congestion costs outside of the CAISO. It also has been well documented that new transmission will be necessary if California is going to meet its 20% RPS by 2010 (Jones et al. 2005a).

New transmission will clearly help with integrating variable renewable energy generation in California, as has been demonstrated in Denmark. Most, if not all of the transmission proposals inside and outside of California are at an early stage, and it is not clear how many of them will be permitted and ultimately developed.

Lots of activity in relation to transmission is taking place inside and outside of California. Extensive new transmission has been proposed to access renewable resources in Tehachapi and the Imperial Valley. In August 2006, the CAISO Board of Governors approved the Sun Path project that will add 1,000 MW of transmission capacity to Southern California and access geothermal and solar resources in the Imperial Valley. Sun Path consists of a 68-mile, 500 kV line running from the Imperial Valley Substation to a new San Felipe Substation and a 10-mile, 500-kV line running from the San Felipe Substation to a new Central Substation. In addition, a 39-mile, 230 kV transmission line will go from the Central Substation to the Sycamore Canyon Substation and a 13-mile 230-kV line will run from the Sycamore Canyon Substation to the Penasquitos Substation. The CAISO Board of Directors is also expected to approve the 500 kV Lake Elsinore Advanced Pump Storage project and the 500 kV and 230 kV Tehachapi transmission projects.

Outside of California, as indicated in Figure 9, over a dozen transmission projects have been proposed, with some of these proposals targeting California as the ultimate market, such as the Frontier line that would originate in Wyoming and end in California. Many of these proposals are at a very early stage, and not all of them may be constructed. Siting issues, and how the costs of these projects will be recovered, are the primary obstacles.

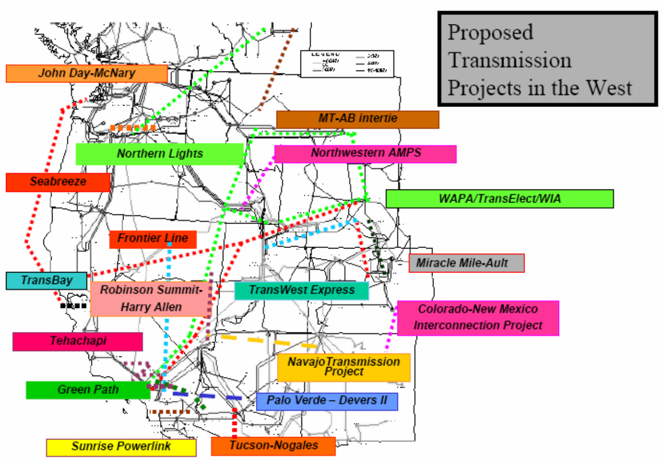


Figure 9: Proposed transmission projects in the West

Source: Thomas Carr. "Transmission in the West: A Primer." Presentation before the National Wind Coordinating Committee's Leadership Forum, July 18, 2006, Broomfield, Colorado. Available at http://www.nationalwind.org/events/transmission/western/2006/presentations/briefing/carr.pdf.

6.0 Findings and Implications for California

This chapter summarizes the findings from the various modeling and simulation studies and operating experience with variable renewable energy generation and compares them to California's situation. Several of these items were referenced in the 2005 Energy Commission consultants report (Dyer et al. 2005), and will be referenced where applicable.

6.1 Ancillary Services

Although the studies may differ in methodology, the time scales considered, and the data and tools that were used, it appears that the costs of integrating wind are less than $6/MWh at energy penetration levels of up to 20 percent for both primary and secondary reserve costs. Factors that affect wind integration costs include how the variability in wind generation interacts with variability in electricity demand, the size of the control area, the resource mix, the strength of the transmission grid, the geographic concentration of wind projects, and how far in advance the power schedules must be submitted to system operators.

In examining these wind integration factors, California appears to have several of these factors in its favor.

- The state has a diverse wind resource in Altamont, Solano, Tehachapi and San Gorgonio. CAISO is the grid operator for much of the state and operates as a single control area.
- CAISO also has elements that work well for variable renewable energy generation: hour-ahead and day-ahead markets and penalty-minimizing imbalance provisions through the use of wind forecasting.
- The scheduled 2008 launch of the CAISO market redesign should help. The CAISO market redesign will allow unbalanced schedules (as opposed to the current requirement of balanced schedules) and may help to create a liquid spot market that will also aid in integrating greater amounts of variable renewable energy generation.

It also has been generally found that additional reserves may be required as the penetration of variable renewable energy generation increases. The IAP study will determine whether additional regulation and operating reserves may be necessary at higher levels of variable renewable energy generation, and will discuss methods of finding additional reserves from existing or new sources should a finding be made that additional reserves are necessary.

Some wind integration studies have suggested reorganizing ancillary service markets, or even suggesting a specific ancillary service for wind. Ireland, New Zealand and the Canadian province of Alberta have suggested a wind-specific ancillary service, with Ireland's proposal perhaps the most developed. Ireland and New Zealand are islands with little or no external interconnections, while Alberta also has limited external interconnections. In contrast, California has extensive external interconnections and a deep resource stack. In any event, establishing a separate ancillary service for a particular set of generation technologies would be a significant departure from how ancillary services are organized currently. The provision of and need for ancillary services is determined for the grid as a whole, not on the characteristics of individual technologies. Planning separate ancillary services for individual technologies may not capture the system diversity of load and other generating resources, and may result in more ancillary services being procured than necessary.

6.2 Wind Forecasting

Wind forecasting has become an important tool as more wind energy has been added. Not including simple persistence, the different wind forecasting models can be roughly categorized into two types: those that apply numerical weather prediction models with equations based on the physical description of the wind project to produce a wind forecast, and those that apply statistical techniques to produce a statistical wind forecast from numerical weather prediction models. The performance of the wind forecasting models appears tied to the complexity of the terrain, the quality of the metrological data, and the wind resource itself. Some grid operators are experimenting with combination wind forecasting, using both physical and statistical techniques.

In 2002, the CAISO became the first, and to date, the only regional transmission operator in the United States to use centralized wind forecasting to predict the output of wind generation. Currently, the PIRP program applies the wind forecasts to the hour-ahead market, although data is collected for the day-ahead market. The CAISO, along with California stakeholders, is in the midst of considering potential changes to PIRP, including adding day-ahead forecasts; addressing the scheduling bias; and changing the treatment of exports out of PIRP. In December 2006, FERC approved a CAISO petition to charge export fees to PIRP facilities that export power out of the CAISO control area.

Only a small proportion of existing variable renewable energy capacity participates in the PIRP program. Some of this is because of the renewable energy generators that are qualifying facilities (QFs) under the Public Utility Regulatory Policies Act. In most cases, QF power purchase agreements place the scheduling requirements on utilities, and utilities can mix the variable renewable energy generation with other generation to minimize imbalances. More variable renewable energy generators may join the CAISO's PIRP program as QF contracts expire. Increasing participation in PIRP will help reduce the per-MWh cost of the PIRP program.

Continuing research by the Commission and utilities is focused on bringing forecasting to the control room and improving resolution of data needed for accurate forecasts. Remote sensing using sonar and Doppler may provide data of high enough spatial and temporal resolution to give schedulers a "look-ahead" on wind resources.

6.3 Transmission

This section will briefly address both existing and new transmission. As has been noted, external interconnections and transmission has been key in helping Denmark and Germany with integrating variable renewable energy generation. However, the need for more transmission is common to both the United States and Europe.

As has been noted, extensive activity is underway in California to plan and construct transmission for tapping renewable resource areas in Tehachapi and the Imperial Valley.

Outside of California, more than a dozen major transmission projects have been proposed in the West, and California is the source or target for some of them, suggesting that integrating variable renewable energy generation could conceivably get easier if some or all of the transmission projects come to fruition. Given the early stage of most of these proposed transmission projects, it will be some time before these transmission projects are of assistance.

High levels of wind generation in Germany and the lack of north-to-south transmission capacity in Germany have sometimes led to generation being routed from the wind-rich areas in Northern Germany to Southern Germany via the transmission networks of the Netherlands, Belgium and France. Renewable integration projects, such as the IAP study, will assess whether high levels of variable renewable energy generation in California may affect not just grid reliability in California but also within WECC.

6.4 Active Management of Wind Generation

Examples of active management of wind projects include ramp rate limits and generation curtailment. Ramp rate limits on wind generation have been imposed in Germany, Ireland, and Scotland and have been proposed in Alberta. With the exception of Germany, these countries does not have the external interconnections or as deep a resource stack as California does. In addition, wind capacity in these countries is often connected at distribution-level voltages, which may have less resilience to accept large ramps. An earlier consultants report for the Energy Commission preliminary suggested that California's resource stack is sufficiently deep enough to handle wind and solar ramping events (Shiu et. al. 2006). The IAP will measure ramp rates with and without variable renewable energy generation and determine whether California has sufficient system capabilities to handle ramping.

Should such ramp rate limits be considered in California, care should be taken to not preclude ramping that may be beneficial to the grid. For example, those times when wind is ramping in the same direction as load. Time-differentiated ramp limits may be preferable, such as imposing up ramp limits when load drops off in the evening, but not in the morning when load increases.

Curtailment of wind generation has occurred in some countries, notably in Germany and Spain. The wind industry can naturally be quite concerned about the prospect of curtailment, as it can play havoc with project economics. Care must be taken to ensure that curtailment is done rarely and only for reliability reasons (akin to shedding of firm load), instead of treating curtailment of variable renewable energy generation as another form of contingency reserve. In addition, questions will certainly arise as to whether variable renewable energy generators should be compensated if curtailed. The IAP will examine the grid impacts of higher levels of variable renewable energy generation, and whether curtailment of variable renewable energy generation may be necessary at certain times.

6.5 Flexible Generation

Most of the new power plants that have been proposed or have come on-line in recent years in California are combined-cycle, natural gas units that are designed to operate at high load factors and have less ability to ramp up and down than older steam units (Jones et. al 2005a). A 2005

Energy Commission consultants report noted that California could use more controllable generation and recommended that the CAISO set metrics for determining how much controllable generation is needed (Dyer et al. 2005). The IAP will consider whether additional infrastructure such as flexible generation (e.g., pumped storage hydro, RMRs) is needed or not to incorporate higher levels of variable renewable energy generation

California may also gain additional flexibility from renegotiating existing contracts. Perhaps more than any other state, California is uniquely exposed to minimum load issues, with must-run qualifying facilities under PURPA and the increased procurement of combined cycle natural gas plants designed to operate only in baseload mode. A 2005 Energy Commission consultants report recommended renegotiating some of those contracts to provide additional system flexibility (Dyer et al. 2005).

6.6 Storage

California has over 4,000 MW of pumped storage hydro capacity, although a 2005 Energy Commission consultants report notes that pumped storage hydro capacity may not be available because of water flow-through requirements or because of low water levels that prevent pumping (Dyer et al. 2005). Other storage options such as flywheels, batteries, fuel cells and CAES may be too costly as compared to other options. Management strategies and market products (i.e. day-night and seasonal energy exchanges with other regions in the West) may also be used like storage options, as noted by the Energy Commission consultants report (Dyer et al. 2005).

6.7 Demand Response

Demand response may help integrate variable renewable energy generation by shifting consumption from times of low variable renewable energy generation to times when variable renewable energy generation is high. California has aggressive demand response programs and goals for all three investor-owned utilities but probably not for the goal of incorporating more variable renewable energy generation. Current goals focus on limiting demand at critical peak times.

Participation in demand response programs has been relatively low, either in the United States or in other countries, perhaps because of transaction costs, information barriers, or that the marginal value of electricity for consumers may be higher than electricity market prices. In 2004, the potential demand response capability in the United States was about 20,500 MW, while the actual peak demand reduction was about 9,000 MW, or 1.3% of peak. Total demand response and load management capabilities have decreased by about one-third because of reduced utility support and investment (U.S. DOE 2006).

7.0 Conclusion

Nearly two-thirds of the world's wind installed capacity is in Europe, with Germany, Spain and Denmark alone accounting for one-half of the world's installed wind capacity. Wind development in Europe, at least initially, differed from the larger utility-scale projects in the United States, particularly in Denmark and Germany, where wind development consisted of smaller (but numerous) wind projects interconnected to the distribution grid. That type of wind development in Denmark and Germany took advantage of the geographic diversity of wind resources to smooth some of the variability in wind.

Similar management strategies between the United States and Europe have begun to emerge as wind development has expanded to other countries with less robust grid infrastructure, as compared to Denmark and Germany, and as wind development has tended towards utility-scale projects that are common in the United States. The implementation of grid codes (although varying in specifics from country to country) is one such example. The need for transmission in both Europe and the United States, not just for wind generation but for all types of generation, is another similarity. Considerable transmission planning and activity is underway in both Europe and the United States.

The particular circumstances in each country, state or region will determine the ease of integrating variable renewable energy generation. These factors include the generating mix; the flexibility of resources in mix; whether there are robust day-ahead markets with deep resource stacks; the location of wind resources; transmission availability; and the size of control areas. Wind integration will almost certainly be more challenging in small control areas, in areas with limited interconnections, or in areas with a small load and/or small resource stacks as compared to regions with larger control areas, extensive interconnections or large loads and/or deep resource stacks. Because these circumstances can vary dramatically, caution should be used in comparing countries or regions with each other.

This report examined how countries overseas have incorporated variable renewable energy generation, what operating strategies have been used to integrate variable renewable energy generation, what lessons have been learned, and whether that experience is transferable to California. For a variety of reasons, the report focused mostly on wind, given that there is more grid-connected wind capacity worldwide than solar; the experience with wind is more widely reported; and the development to date of solar systems has been of small, distributed systems and, at least as of now, does not face the same system integration issues as wind power.

Some highlights of integration strategies and findings from various country reports include:

- Strategies implemented to incorporate wind include wind forecasting, grid codes, curtailment, wind turbine modeling and verification, demand response, and transmission planning and development.
- To date, grid codes have featured these major themes: requiring wind turbines to ride through grid faults; increasing or decreasing power generation at the TSO's request; supplying reactive power; adjusting power generation in response to frequency changes; and controlling or limiting ramping increases.

- Various European transmission system operators have implemented more control requirements for wind than have been seen in the United States so far, such as ramp rate limits and the requirement to provide reserves and frequency control. In general, these control requirements have been a function of small control areas or limited transmission interconnections, or both.
- Some of the more stringent wind control strategies have been proposed in countries that have little or no grid interconnections, and these particular circumstances need to be kept in mind when comparing international wind integration experiences. Ramping events will be of more concern to small grids, or grids with few external interconnections, or grids with a large concentration of wind projects in one region.
- Countries with "must-take" requirements in their renewable energy feed-in laws tend to have the toughest grid code provisions with regards to wind curtailment.
- In describing various ancillary services, Europe and the United States use different terminology. In Europe, primary reserves assists with the short-term, minute-to-minute balancing and control of the power system frequency, and is equivalent in the United States to regulation. Secondary reserves in Europe take over for primary reserves 10 to 30 minutes later, freeing up capacity to be used as primary reserves. The closest terminology in the United States for secondary reserves is either operating reserves or load following reserves, which may include both spinning and non-spinning components. Longer-term reserves in Europe are called tertiary reserves and are available in the periods after secondary reserves. Tertiary reserves are closest to supplemental reserves in the United States, although the time scales may be different between Europe and the United States.
- Reconstituting existing reserve services may be necessary as higher levels of variable renewable energy generation is added.
- Submitting schedules with shorter periods of time before the real-time market begins will allow for more accurate predictions of wind generation, although some trade-offs are involved.
- Various wind integration studies and transmission system operators have reported some operating issues with wind generation, such as minimum load and high ramp rates. A New Zealand wind integration study used minimum load to determine how much wind could be accommodated on its grid.
- For ramping, various studies suggest that wind will ramp up and down within ±10% of capacity much of the time over an hour. Handling wind ramping could be managed with sufficient regulation or load following generation; wind forecasting to predict variability and ramping events; performance limits on the wind generation such as ramp rate limits; or sharing reserves or energy imbalances over multiple control areas.
- Efforts are also underway on improving the modeling of wind projects for determining the potential impacts on system reliability during the process of evaluating interconnection applications from wind generators.

In terms of wind integration costs, the results of various studies conducted to date in the United States and overseas have been reasonably consistent. Overall, the findings can be summarized as follows:

- The cost for integrating wind is non-zero and increases as the proportion of wind generation to conventional generating resources or peak load increases;
- Reserve costs attributed to wind integration are relatively small at wind penetration levels of less than 20%. How the variability and uncertainty of wind generation interacts with variations in load and load forecasting uncertainty has a large impact on the level of wind integration costs.
- Level of geographic concentration of wind projects also affects wind integration costs.
- Unit commitment impacts have been a major focus of wind integration studies in the United States but have not been addressed as extensively in the European studies to date.
- Based on several European studies that estimated the costs of additional reserves with wind generation, costs were generally less than $6/MWh at wind energy penetration levels up to 20%, although the costs varied significantly among the individual studies.
- Reserve costs for wind generation are dependent on the characteristics of the grid that is integrating wind, the adequacy and characteristics of the existing reserves, and the specific reserve requirements for each grid.
- Studies estimating the capacity credit of wind power in Europe determined that wind has a capacity credit greater than zero, and also that the capacity credit decreases as the level of wind generation rises.
- Factors that affect the capacity credit of wind include present levels of wind generation on the grid; the quality of the wind resource; the capacity factor of the wind projects; whether demand and wind generation are correlated or uncorrelated; the degree of system security; and the strength of the transmission interconnections.

As time goes on, more similarities than differences are apparent between Europe and the United States as variable renewable energy generation increases in market penetration. These similarities are sparking information exchange and transfer through forums such as the International Energy Agency, the Institute of Electrical and Electronics Engineers and the Utility Wind Integration Group (UWIG). That, in turn, can help elevate prominent issues and make the task of developing solutions and options for integrating variable renewable energy generation easier.

7.1 Benefits to California

California has perhaps the most significant and diverse RPS in the United States in terms of the level (20%), timeframe (2010) and the amount of renewable energy capacity that may be required to meet the target. Transmission and the integration of variable renewable energy generation remain challenges that need to be addressed in order for California to meet its RPS goals. Various countries in Europe have experience with integrating high levels of variable renewable energy generation. By reviewing and highlighting strategies and practices that have been used to integrate wind in other states and in other countries in this report, the IAP may incorporate some of these strategies and practices as options to test potential effectiveness in integrating variable renewable energy generation in the state. The hope is that California projects and utilities can begin to evaluate and incorporate some of these approaches and to test their effectiveness in integrating renewables.

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Appendices

Appendix A Review of International Experience Integrating Variable Renewable Energy Generation. Appendix A: Denmark

This appendix is available in a separate volume, CEC-500-2007-XXX-APA.

Appendix B Review of International Experience Integrating Variable Renewable Energy Generation. Appendix B: Germany

This appendix is available in a separate volume, CEC-500-2007-XXX-APB.

Appendix C Review of International Experience Integrating Variable Renewable Energy Generation. Appendix C: India

This appendix is available in a separate volume, CEC-500-2007-XXX-APC.

Appendix D Review of International Experience Integrating Variable Renewable Energy Generation. Appendix D: Spain

This appendix is available in a separate volume, CEC-500-2007-XXX-APD.