



National Renewable Energy Laboratory

A national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy

Innovation for Our Energy Future

The Role of Energy Storage with Renewable Electricity Generation

Paul Denholm, Erik Ela, Brendan Kirby,
and Michael Milligan

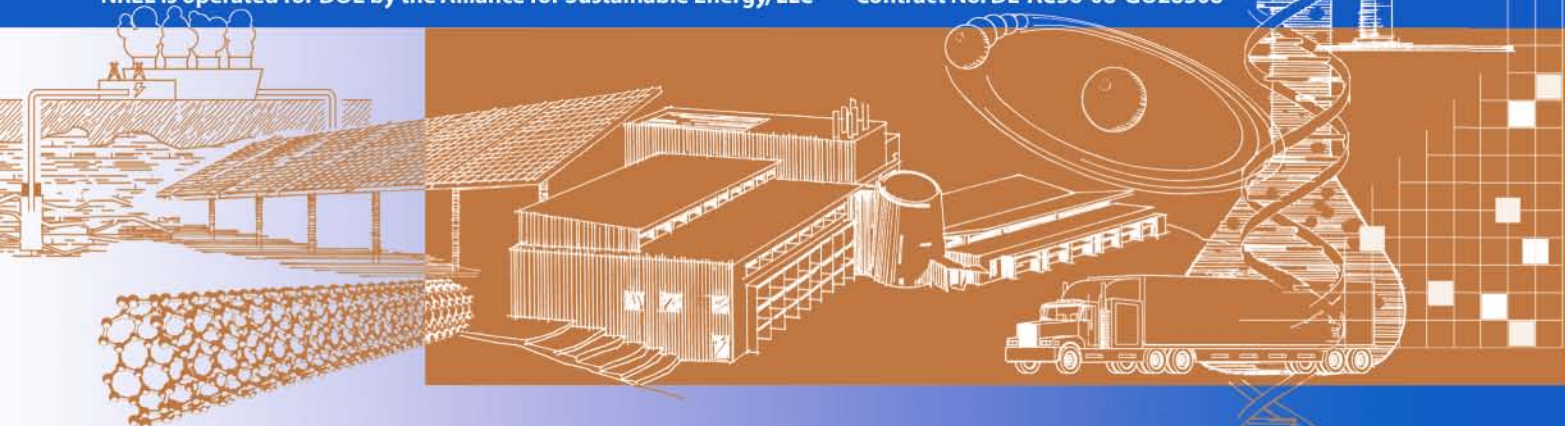
Technical Report

NREL/TP-6A2-47187

January 2010

NREL is operated for DOE by the Alliance for Sustainable Energy, LLC

Contract No. DE-AC36-08-GO28308



The Role of Energy Storage with Renewable Electricity Generation

Paul Denholm, Erik Ela, Brendan Kirby,
and Michael Milligan

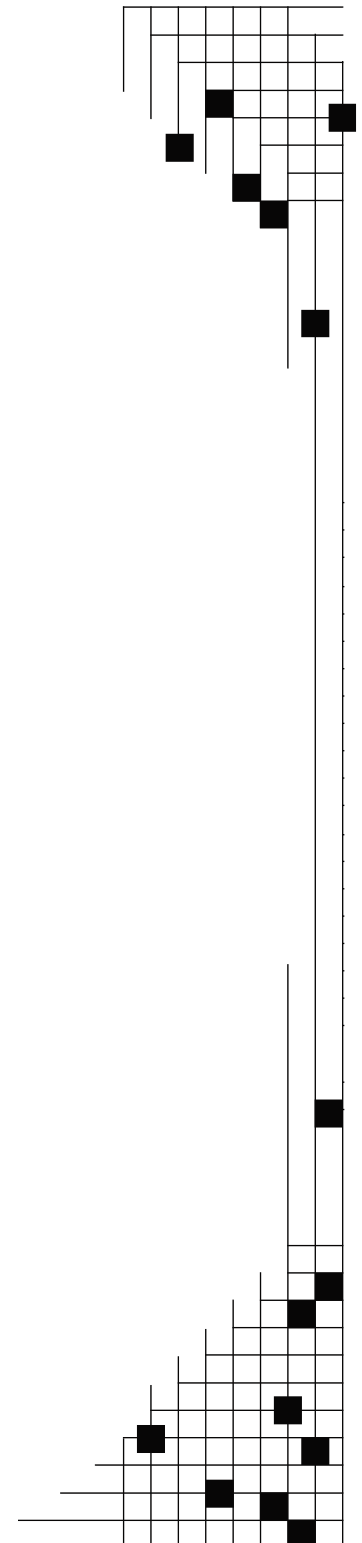
Prepared under Task No. WER8.5005

Technical Report
NREL/TP-6A2-47187
January 2010

National Renewable Energy Laboratory
1617 Cole Boulevard, Golden, Colorado 80401-3393
303-275-3000 • www.nrel.gov

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

Contract No. DE-AC36-08-GO28308



NOTICE

This report was prepared as an account of work sponsored by an agency of the United States government. Neither the United States government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States government or any agency thereof.

Available electronically at <http://www.osti.gov/bridge>

Available for a processing fee to U.S. Department of Energy
and its contractors, in paper, from:

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: <mailto:reports@adonis.osti.gov>

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering: <http://www.ntis.gov/ordering.htm>



Printed on paper containing at least 50% wastepaper, including 20% postconsumer waste

Acknowledgments

The authors wish to thank the following people for their review and other contributions: Doug Arent, Easan Drury, Vahan Gevorgian, Michelle Kubik, Jim Leyshon, Sean Ong, and Brian Parsons of the National Renewable Energy Laboratory (NREL); Jonah Levine of the University of Colorado; Mark O'Malley of the Electricity Research Center, University College Dublin; and Samir Succar of the Natural Resources Defense Council.

List of Acronyms

AC	alternate current
AGC	automatic generation control
AS	ancillary services
CAES	compressed-air energy storage
CCGT	combined-cycle gas turbine
CCR	capital charge rate
CSP	concentrating solar power
DC	direct current
ERCOT	Electric Reliability Council of Texas
EVs	electric vehicles
GW	gigawatt
ISO	independent system operators
LaaR	Load Acting as a Resource (program)
MW	megawatt
NERC	North American Electric Reliability Corporation
PHS	pumped hydro storage
PV	photovoltaics
RTO	regional transmission organization
RE	renewable energy
SMES	superconducting magnetic energy storage
T&D	transmission and distribution
V2G	vehicle to grid
VG	variable generation

Table of Contents

1 Introduction	1
2 Operation of the Electric Grid	2
3 Electricity Storage in the Existing Grid	6
3.1 Development of Energy Storage in Regulated Markets	6
3.2 The Economics of Energy Storage in Restructured Markets.....	8
3.3 Other Applications of Energy Storage.....	12
3.4 Summary of Energy Storage Applications in the Current Grid.....	13
4 Impacts of Renewables on the Grid and the Role of Enabling Technologies	17
4.1 Costs of Wind and Solar Integration from Previous Studies	19
4.2 Limiting Factors for Integration of Wind and Solar Energy.....	23
5 Storage and Flexibility Options for Renewables-Driven Grid Applications	34
5.1 The Flexibility Supply Curve.....	34
5.2 Deployment and Operational Balancing of Renewable Energy – Individual Plant Storage vs. Power System Storage	36
5.3 Energy Storage Technologies and Applications	38
5.4 Electric Vehicles and the Role of Vehicle to Grid.....	44
6 Conclusions	46
Bibliography	47
References	48

List of Tables

Table 3.1. Historical Values of Energy Storage in Restructured Electricity Markets	10
Table 3.2. Traditional Major Grid Applications of Energy Storage	14
Table 4.1. Summary of Recent Wind Integration Cost Studies	20
Table 5.1. Dedicated Renewable Applications of Energy Storage and Their Whole-Grid Counterpart	37
Table 5.2. Three Classes of Energy Storage	38

List of Figures

Figure 2.1. Hourly loads from ERCOT 2005	2
Figure 2.2. System load following and regulation	3
Figure 2.3. Optimal and reserve constrained dispatch	5
Figure 3.1. Historical fuel costs for intermediate load power plants	7
Figure 3.2. Relationship between the annual benefit of storage and capital cost using different capital charge rates	11
Figure 4.1. Impact of net load from increased use of renewable energy	18
Figure 4.2. Dispatch with low VG penetration	24
Figure 4.3. Dispatch with higher VG penetration	25
Figure 4.4. Relationship between price and load in PJM in 2002	27
Figure 4.5. Contribution from inflexible generation	28
Figure 4.6. Effect of decreasing minimum load point on increased use of RE	29
Figure 4.7. Average curtailment rate as a function of VG penetration for different flexibilities in ERCOT	30
Figure 4.8. Marginal curtailment rate as a function of VG penetration for different system flexibilities in ERCOT	30
Figure 4.9. Relative cost of VG as a function of VG penetration for different system flexibilities in ERCOT	31
Figure 4.10. Option for increasing the use of VG by decreasing curtailment	32
Figure 4.11. Reduction of curtailment resulting from addition of energy storage	33
Figure 5.1. Flexibility supply curve	34
Figure 5.2. Energy storage applications and technologies	39

1 Introduction

Renewable energy sources, such as wind and solar, have vast potential to reduce dependence on fossil fuels and greenhouse gas emissions in the electric sector. Climate change concerns, state initiatives including renewable portfolio standards, and consumer efforts are resulting in increased deployments of both technologies. Both solar photovoltaics (PV) and wind energy have variable and uncertain (sometimes referred to as “intermittent”)¹ output, which are unlike the dispatchable sources used for the majority of electricity generation in the United States. The variability of these sources has led to concerns regarding the reliability of an electric grid that derives a large fraction of its energy from these sources as well as the cost of reliably integrating large amounts of variable generation into the electric grid. Because the wind doesn’t always blow and the sun doesn’t always shine at any given location, there has been an increased call for the deployment of energy storage as an essential component of future energy systems that use large amounts of variable renewable resources. However, this often-characterized “need” for energy storage to enable renewable integration is actually an economic question. The answer requires comparing the options to maintain the required system reliability, which include a number of technologies and changes in operational practices. The amount of storage or any other “enabling” technology used will depend on the costs and benefits of each technology relative to the other available options.

To determine the potential role of storage in the grid of the future, it is important to examine the technical and economic impacts of variable renewable energy sources. It is also important to examine the economics of a variety of potentially competing technologies including demand response, transmission, flexible generation, and improved operational practices. In addition, while there are clear benefits of using energy storage to enable greater penetration of wind and solar, it is important to consider the potential role of energy storage in relation to the needs of the electric power system as a whole.

In this report, we explore the role of energy storage in the electricity grid, focusing on the effects of large-scale deployment of variable renewable sources (primarily wind and solar energy). We begin by discussing the existing grid and the current role that energy storage has in meeting the constantly varying demand for electricity, as well as the need for operating reserves to achieve reliable service. The impact of variable renewables on the grid is then discussed, including how these energy sources will require a variety of enabling techniques and technologies to reach their full potential. Finally, we evaluate the potential role of several forms of enabling technologies, including energy storage.

¹ The use of the term “intermittent” has been questioned by the wind energy community as being technically inaccurate. Intermittent implies a short-term “on-off” cycle while the output of wind experiences maximum variations more typically on the order of 10% per hour. Solar PV is perhaps somewhat more “intermittent” because it follows a daily on-off cycle. The description “variable” or “variable and uncertain” has been proposed as a more technically accurate description of the output of a wind power plant (Smith and Parsons 2007).

2 Operation of the Electric Grid

The operation of electric power systems involves a complex process of forecasting the demand for electricity, and scheduling and operating a large number of power plants to meet that varying demand. The instantaneous supply of electricity must always meet the constantly changing demand, as indicated in Figure 2.1. It shows the electricity demand patterns for three weeks for the Electric Reliability Council of Texas (ERCOT) grid during 2005.² The seasonal and daily patterns are driven by factors such as the need for heating, cooling, lighting, etc. While the demand patterns in Figure 2.1 are for a specific region of the United States, many of the general trends shown in the demand patterns are common throughout the country. To meet this demand, utilities build and operate a variety of power plant types. Baseload plants are used to meet the large constant demand for electricity. In the United States, these are often nuclear and coal-fired plants, and utilities try to run these plants at full output as much as possible. While these plants (especially coal) can vary output, their high capital costs, and low variable costs (largely fuel), encourage continuous operation. Furthermore, technical constraints (especially in nuclear plants) restrict rapid change in output needed to follow load. Variation in load is typically met with load-following or “cycling” plants. These units are typically hydroelectric generators or plants fueled with natural gas or oil. These “load-following” units are further categorized as intermediate load plants, which are used to meet most of the day-to-day variable demand; and peaking units, which meet the peak demand and often run less than a few hundred hours per year.

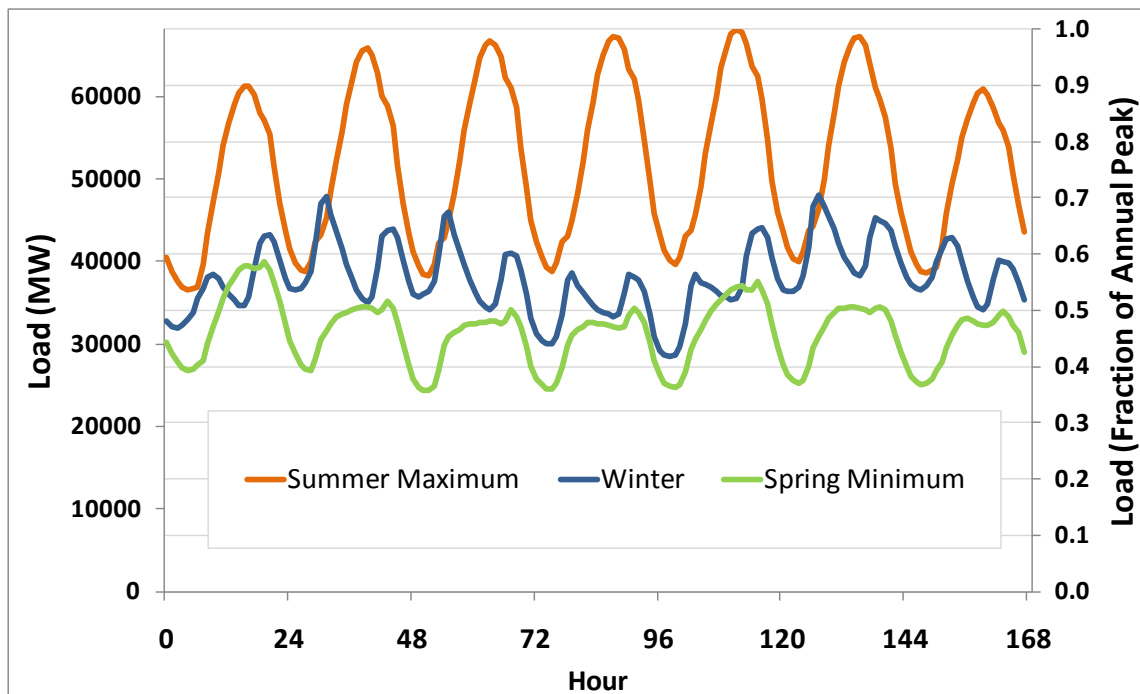


Figure 2.1. Hourly loads from ERCOT 2005

² Most of Texas (about 85% of the population) is within the ERCOT grid, which is largely independent of the two larger U.S. grids.

In addition to meeting the predictable daily, weekly, and seasonal variation in demand, utilities must keep additional plants available to meet unforeseen increases in demand, losses of conventional plants and transmission lines, and other contingencies. This class of responsive reserves is often referred to as operating reserves and includes meeting frequency regulation (the ability to respond to small, random fluctuations around normal load), load-forecasting errors (the ability to respond to a greater or less than predicted change in demand), and contingencies (the ability to respond to a major contingency such as an unscheduled power plant or transmission line outage) (NERC 2008).³ Both frequency regulation and contingency reserves are among a larger class of services often referred to as ancillary services, which require units that can rapidly change output. Figure 2.2 illustrates the need for rapidly responding frequency regulation (red) in addition to the longer term ramping requirements (blue). In this utility system, the morning load increases smoothly by about 400 megawatts (MW) in two hours. During this period, however, there are rapid short-term ramps of ± 50 (MW) within a few minutes.

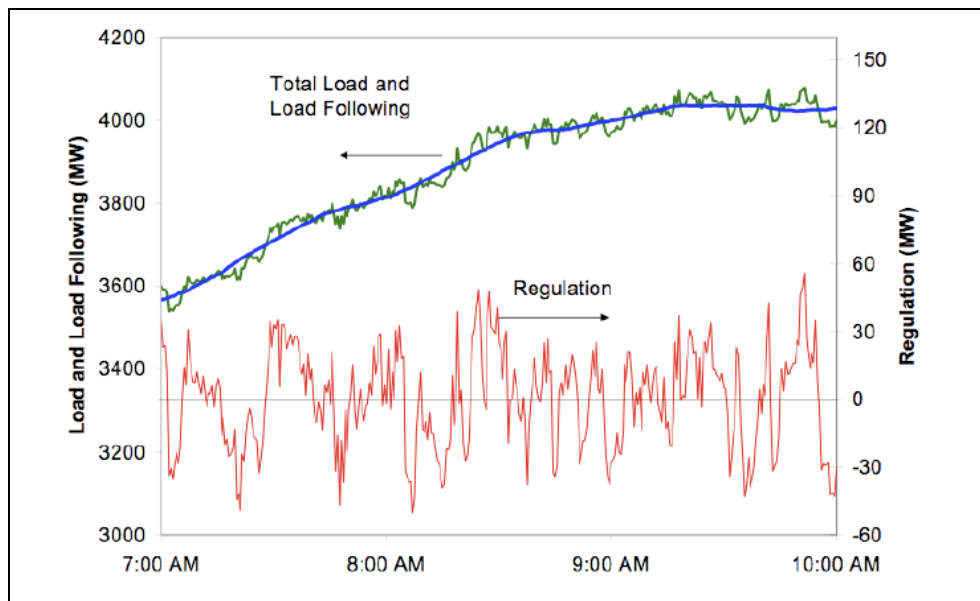


Figure 2.2. System load following and regulation. Regulation (red) is the fast fluctuating component of total load (green) while load following (blue) is the slower trend (Kirby 2004)

Because of the rapid response needed by both regulation and contingency reserves, a large fraction of these reserves are provided by plants that are online and “spinning” (as a result, operating reserves met by spinning units are sometimes referred to as spinning reserves.)⁴ Spinning reserves are provided by a mix of partially loaded power plants or responsive loads. The need for reserves increases the costs and decreases the efficiency of

³ Operating reserves are primarily capacity services (the ability to provide energy on demand) as opposed to actual energy services.

⁴ The nomenclature around various ancillary services (especially spinning reserves) varies significantly. While the NERC glossary indicates that spinning reserve applies to both contingency and frequency regulation, the term spinning reserve often is used to refer to only contingency reserves. For additional discussion of nomenclature around contingency and spinning reserves, see Rebours and Kirschen 2005.

an electric power system compared to a system that is perfectly predictable and does not experience unforeseen contingencies. These costs result from several factors. First, the need for fast-responding units results in uneconomic dispatch – because plants providing spinning reserve must be operated at part load, they potentially displace more economic units.⁵ (Flexible load-following units are often either less efficient or burn more expensive fuel than “baseload” coal or nuclear units.) Second, partial loading can reduce the efficiency of individual power plants. Finally, the reserve requirements increase the number of plants that are online at any time, which increases the capital and O&M costs.

Figure 2.3 provides a simplified illustration of the change in dispatch (and possible cost impacts) needed to provide operating reserves. The figure on the left shows an “ideal” dispatch of a small electric power system. Two baseload units provide most of the energy, while an intermediate load and two peaking units provide load following. In the “ideal” dispatch, it is possible that the intermediate load unit cannot rapidly increase output to provide operating reserves. Furthermore, during the transition periods when the load-following units are nearing their full output – but before additional units are turned on – there may be insufficient capacity left in the load-following units to provide necessary operating capacity for regulation or contingencies. A dispatch that provides the necessary reserves is provided on the right. In this case, lower-cost units reduce output to accommodate the more flexible units providing reserves. This increases the overall cost of operating the entire system.

⁵ This “opportunity cost” associated with uneconomic dispatch is the dominant source of reserve costs (Kirby 2004).

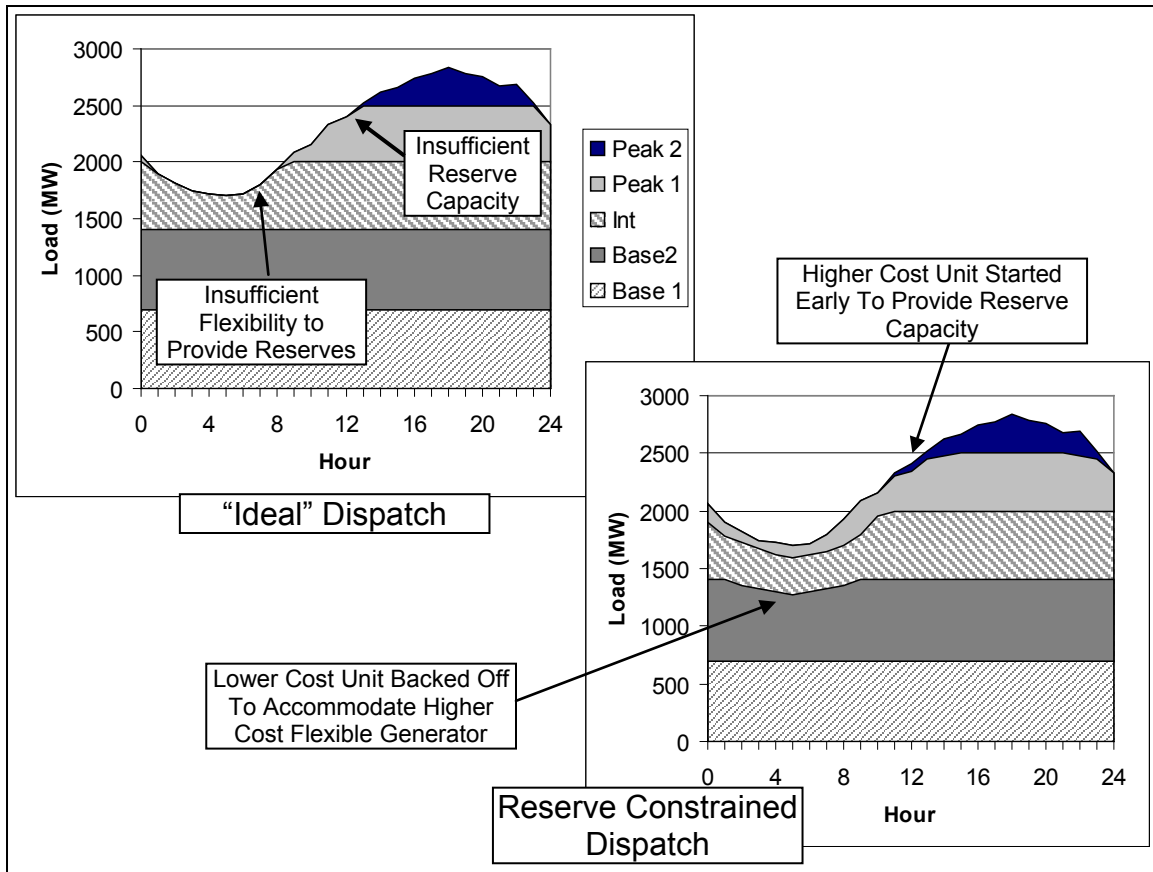


Figure 2.3. Optimal and reserve constrained dispatch

The need for operating reserves and the large variation in demand restricts the contribution from low-cost baseload units and increases the need for units that can vary output to provide both load-following and ancillary services. As a consequence, utility operators have long pursued energy storage as one potential method of better utilizing baseload plants and providing an alternative to lower efficiency thermal generators for meeting variations in demand.

3 Electricity Storage in the Existing Grid

The challenges associated with meeting the variation in demand while providing reliable services has motivated historical development of energy storage. While a number of pumped hydro storage (PHS) plants⁶ were built in the United States before 1970, significant interest, research, and funding for new storage technologies began in the early 1970s, associated with dramatic increases in oil prices. This period also saw the largest deployment of PHS based on its competitive economics compared to alternative sources of intermediate load and peaking energy.

3.1 Development of Energy Storage in Regulated Markets

Deployment of energy storage is dependent on the economic merits of storage technologies compared to the more conventional alternatives used to follow load. Before the advent of low-cost, efficient gas turbines now typically used to follow load and provide reserves, utilities often relied on oil- and gas-fired steam turbines (and hydroelectric dams where available). In the 1970s, dramatic price increases in oil and natural gas occurred, along with concerns about security of supply. This led to the Powerplant and Industrial Fuel Use Act, restricting use of oil and gas in new power plants (EIA 2009b). Utilities expected to bring online many new coal and nuclear plants to meet baseload demand, but were left with limited options to provide load-following and peaking services.⁷ This led utilities to actively evaluate pumped hydro (along with other storage technologies) as alternatives to fossil-fueled intermediate load and peaking units. The economic analysis and justification of new energy storage facilities during this period was based on a direct comparison of the energy and capacity provided by energy storage to an equivalently sized fossil plant, (choosing the lower net-cost option) which largely ignored any additional operational benefits energy storage can provide.⁸ Figure 3.1 provides a simple framework of comparing these technologies over time. In the figure, the variable (fuel-related) costs are shown for a storage device and fossil-fueled alternatives. In this figure, the storage technology is assumed to be fueled with off-peak coal and has an effective round-trip efficiency of 75%.⁹

⁶ PHS stores energy by pumping water from a lower reservoir to an upper reservoir and releasing that stored water through a conventional hydroelectric generator. Additional information about PHS is provided in Section 5.

⁷ Concerns about the availability of oil and other peaking fuels in this period was so great that an international conference (including the U.S. National Academy of Sciences) on the subject in 1979 described energy storage as “a vital element in mankind’s quest for survival and progress” (Silverman 1980).

⁸ See, for example, EPRI 1976. Here, the proposed method for comparing energy storage to conventional alternatives is based solely on the value of energy and firm capacity value without any actual quantification of operational benefits.

⁹ This would be a typical assumption for a pumped hydro plant built during the 1970s and 1980s (EPRI 1976).

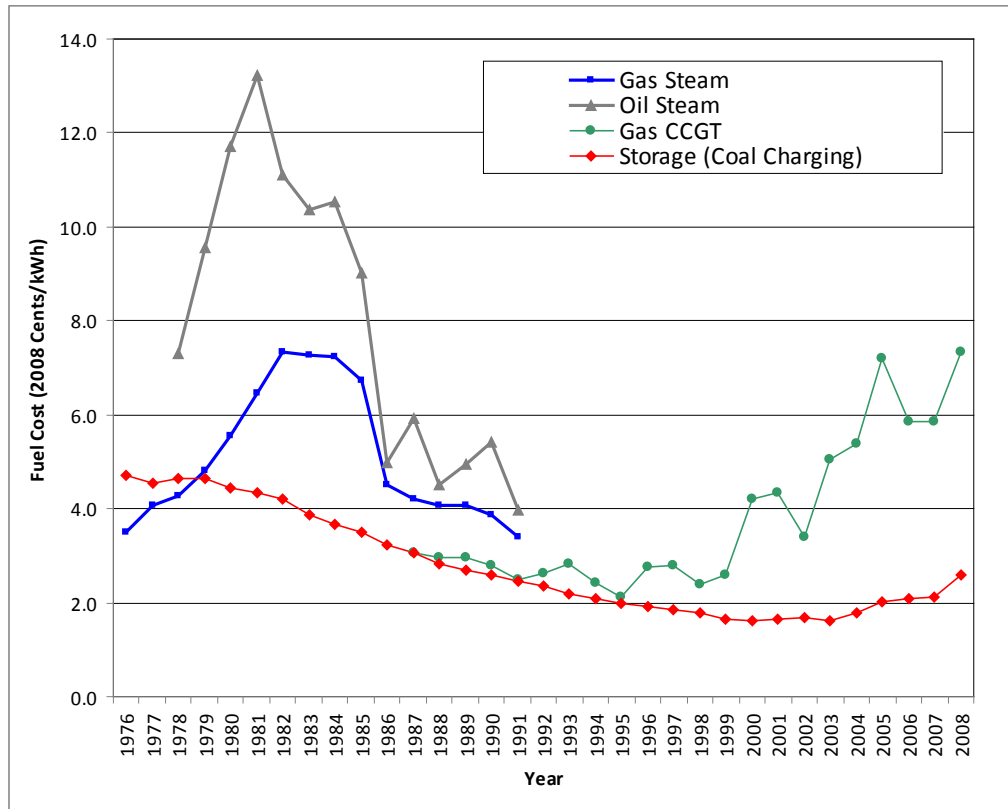


Figure 3.1. Historical fuel costs for intermediate load power plants¹⁰

Figure 3.1 shows that the variable cost of providing energy from a storage device was much lower than alternatives available in the mid-1970s and early 1980s. While Figure 3.1 provides the fuel costs, the total economics of storage must also consider the fixed costs. During the mid- to late 1970s, gas-fired combined cycle plants were not significantly less expensive than pumped hydro, with cost estimates of \$110-\$280/kW for a 10-hour PHS device and \$175-275/kW for a combined-cycle generator (EPRI 1976). As a result, pumped hydro appeared more economic than alternative generation sources during this time period, even without considering additional operation benefits. It was expected that oil and gas prices would remain high, and that off-peak energy would be widely available (and even less expensive) due to anticipated large-scale deployment of nuclear power plants.

During the mid- to late 1970s, much of the nation's 20 GW of pumped hydro storage was initiated (ASCE 1993), along with significant research and development in a variety of other storage technologies including several battery types, capacitors, flywheels, and superconducting magnetic storage (DOE 1977). Growth projections for energy storage during this period included significant increases of several types (Boyd et al. 1983). However, most PHS development, along with interest in and deployment of other

¹⁰ This figure is intended to represent general trends as opposed to absolute costs. In this figure, fuel prices and generation characteristics are derived from various data sets from the Energy Information Administration.

emerging storage technologies, ended in the 1980s after dramatic reduction in the price of natural gas, increased efficiency and reduced costs of flexible combined-cycle and simple-cycle natural gas turbines, and repeal of the Fuel Use Act in 1987. While estimates from the 1970s place combined-cycle gas turbine (CCGT) units and PHS at similar costs, by the early 2000s, PHS was estimated to be about twice the cost of a CCGT. As a result, even with the increased cost of gas, this dramatic increase in PHS cost (along with the many other factors discussed previously) limited the economic competitiveness of PHS vs. gas-fired generators.¹¹ Furthermore, while coal prices continued to drop, the limited nuclear build-out eliminated a source of low-cost off-peak electricity. Finally, the simplistic treatment of the economic benefits of energy storage technologies was also a limiting factor. One of the main benefits of energy storage is its ability to provide multiple services, including load leveling (and associated benefits such as a reduction in cycling-induced maintenance) along with regulation and contingency reserves and firm capacity.¹² However, it has always been somewhat difficult to quantify these various value streams without fairly sophisticated modeling and simulation methods, (especially before the advent of energy and ancillary service markets, which will be discussed in the next section). Because the economic analysis is difficult, and benefits of storage are often uncertain, utilities tend to rely on more traditional generation assets, especially in regulated utilities where risk is minimized and new technologies are adopted relatively slowly.¹³

Combined, these factors have restricted deployment of utility-scale energy storage in the United States. Besides PHS, deployment has been limited to a single 110 MW compressed-air energy storage (CAES) facility, and a variety of small projects.¹⁴ A more comprehensive discussion of energy storage technologies and their status is provided in Section 5.

3.2 The Economics of Energy Storage in Restructured Markets

Despite the lack of significant new construction, interest in energy storage never completely disappeared during the period of low-cost peaking fuels. Research and development has continued, along with an increasing number of proposed projects.

¹¹ PHS also takes longer to build (increasing the risk for investors), requires additional permits, and is typically located farther from load centers, which requires more transmission than gas-fired generators. PHS may also face greater environmental opposition (Strauss 1991).

¹² This problem has been noted many times. For example, “traditionally, when electric utilities evaluate generating additions to their facilities, the evaluation process considers the contribution of each alternative to both capacity and energy requirements. However, the evaluation process often neglects or inaccurately measure potential costs and benefits not directly related to capacity and energy. Operating considerations that reflect the ability (or inability) of a generation resource to respond to the electric system’s dynamic operating needs usually fall into this category.” (Jabbour and Wells 1992).

¹³ Private investors tend to favor lower capital cost investments with faster construction times (i.e., combustion turbines and combined-cycle plants), even if they have higher operating costs, because this reduces perceived economic risk.

¹⁴ To place these values in perspective, between 1993 and 2008, more than 320 GW of conventional capacity was constructed in the United States. With the exception of the completion of previously started PHS facilities and a few demonstration projects, no significant storage capacity was added. The total U.S. utility storage capacity of about 20 GW in 2008 is less than 2% of the total installed generation capacity (EIA 2009a).

Recent renewed interest in energy storage has been motivated by at least five factors: advances in storage technologies, an increase in fossil fuel prices, the development of deregulated energy markets including markets for high-value ancillary services, challenges to siting new transmission and distribution facilities, and the perceived need and opportunities for storage with variable renewable generators.

Emergence of wholesale electricity markets along with increased volatility in natural gas prices has created new opportunities and interest in energy storage. As shown in Figure 3.1, rising natural gas prices in the early 2000s increased the cost-competitiveness of energy storage. However, perhaps the single greatest motivation for proposals to build new energy storage is the creation of markets for both energy and ancillary services including regulation, contingency reserves, and capacity. As of 2009, wholesale energy markets exist in parts of more than 30 states and cover about two-thirds of the U.S. population (IRC 2009). The markets provide real, transparent data for both utilities and independent power producers to consider the opportunities for energy storage. Market data allows evaluation of both the economic yield and optimum location of energy storage devices for arbitrage – the ability to purchase low-cost off-peak energy and re-sell this energy during on-peak periods. Furthermore, the benefits of providing operating reserves and other ancillary services from energy storage can now be evaluated. Previously, the value of these services was largely “hidden” in utilities’ cost of service, and the cost of providing operating reserves, for example, was rarely calculated. The high value of these services is now recognized, and the advantages of energy storage in providing these services is evident, especially because these services generally require fast response and limited actual energy delivery, two qualities that are well-suited to many energy storage devices.

Historical market data can be used to evaluate the potential profitability of energy storage devices that provide various services. Table 3.1 provides the results of several studies of U.S. electricity markets.

Table 3.1. Historical Values of Energy Storage in Restructured Electricity Markets

Market Evaluated	Location	Years Evaluated	Annual Value (\$/kW)	Assumptions
Energy Arbitrage	PJM ^a	2002-2007	\$60-\$115	12 hour, 80% efficient device. Range of efficiencies and sizes evaluated ¹⁵
	NYISO ^b	2001-2005	\$87-\$240 (NYC) \$29-\$84 (rest)	10 hour, 83% efficient device. Range of efficiencies and sizes evaluated.
	USA ^c	1997-2001	\$37-\$45	80% efficient device, Covers NE, No Cal, PJM
	CA ^d	2003	\$49	10 hour, 90% efficient device.
Regulation	NYISO ^b	2001-2005	\$163-248	
	USA ^e	2003-2006	\$236-\$429	PJM, NYISO, ERCOT, ISONE
Contingency Reserves	USA ^e	2004-2005	\$66-\$149	PJM, NYISO, ERCOT, ISONE

^a Sioshansi et al. 2009

^b Walawalkar et al. 2007

^c Figueiredo et al. 2006

^d Eyer et al. 2004

^e Denholm and Letendre 2007

The values in Table 3.1 can be translated into a maximum capital cost for the applicable storage technology (equal to the maximum cost of a storage device that can be supported by the revenues available). Figure 3.2 provides a generic conversion between annual costs and total capital costs. This conversion is performed by dividing the annual revenues by the capital charge rate, which produces a total capital cost.¹⁶ The capital charge rate (also referred to as a fixed-charge rate or capital recovery factor) refers to the fraction of the total capital cost that is paid each year to finance the plant. It should be noted that this cost does not include any operation and maintenance costs.¹⁷

¹⁵ This study analyzed devices up to 40 hours, and found rapidly diminishing returns for devices with storage capacity greater than about 10 hours. The majority of arbitrage benefits are within a day, as opposed to over larger time periods. In addition, while short-term price variation is highly predictable, long-term variations are less predictable, which reduces the certainty of long-term arbitrage opportunities.

¹⁶ This is the inverse of the process of calculating an annualized cost from a capital cost by multiplying by the capital charge rate.

¹⁷ These values also assume that frequency regulation is an energy- and cost-neutral service.

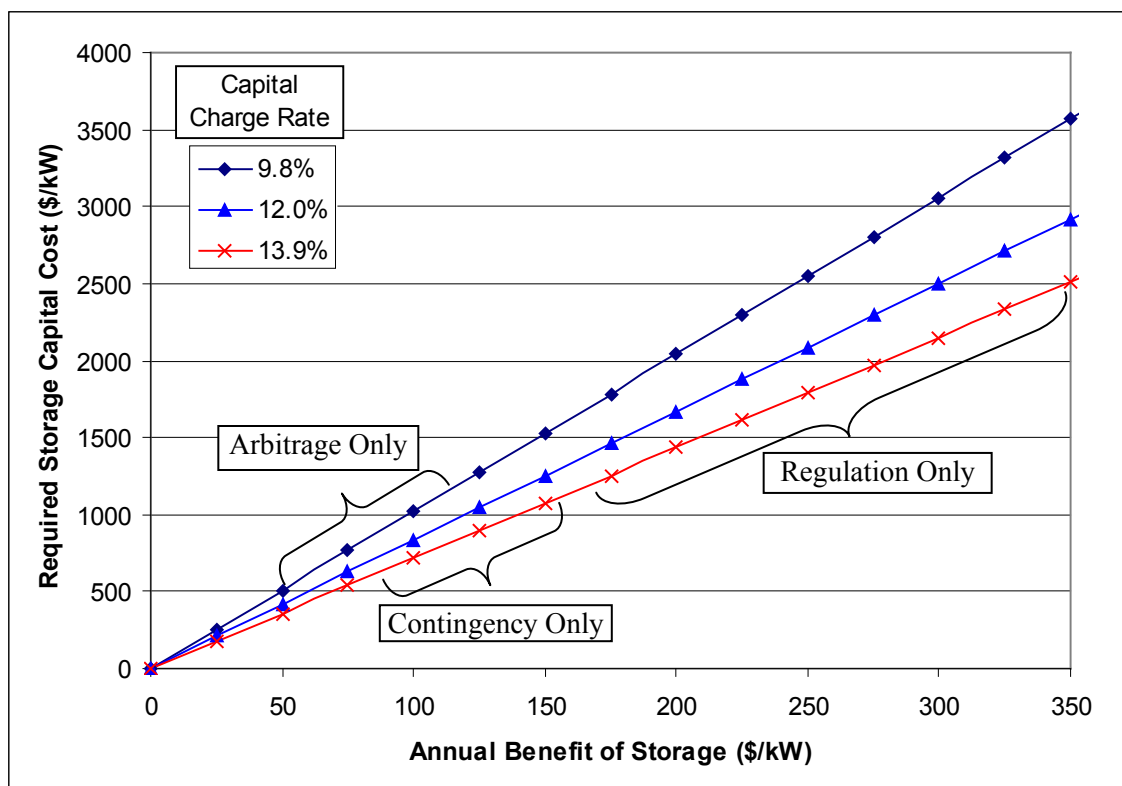


Figure 3.2. Relationship between the annual benefit of storage and capital cost using different capital charge rates¹⁸

Figure 3.2 shows the range of values and corresponding capital costs for three types of operation: energy arbitrage, contingency reserves, and frequency regulation. In general, energy arbitrage provides the least value. Outside of New York City, the maximum annual value in Table 3.1 for arbitrage was \$115/kW (for a 20-hour device), which would translate into a capital cost of \$827-1,170/kW – this is below current estimates for most energy storage technologies. While there is significant uncertainty in costs, most energy storage assessments indicate that few commercially available bulk energy storage technologies are deployable for less than \$1,000/kW.¹⁹ This reveals the same challenging economics as comparing a storage device to a conventional generator as discussed in Section 3-1. The value of energy arbitrage alone does not appear to justify the deployment of energy storage at current technology costs and electricity prices.

The value of energy storage increases when taking advantage of other individual sources of revenue or even combined services. A device with sufficient energy capacity for energy arbitrage would likely be able to receive capacity payments in locations where

¹⁸Capital charge rate (CCR) of 9.8% from EPRI 2003, CCR of 12% from Butler et al. 2003, CCR of 13.9% from Eyer et al. 2004.

¹⁹ CAES is one possible exception, but requires analysis of both the electricity price and natural gas prices. See Section 5 and the references in the Bibliography for additional discussion of storage costs.

capacity markets now exist; recent data in the PJM market indicates an additional potential value of \$40-90/kW-year.²⁰

Alternatively, contingency reserves offer a higher value²¹ than energy arbitrage and also require less energy capacity. Obtaining the values for energy arbitrage in Table 3.1 generally requires a device with at least 10 hours of storage capacity; contingency reserves can require as little as 30 minutes, depending on the market and market reliability rules (PJM 2009b). The challenge for a device providing contingency reserves is that the device must be able to respond rapidly, typically in a few minutes or less. Frequency regulation is even more demanding, requiring continuous changes in output, frequent cycling, and fast response. It is also the highest-value opportunity for an energy storage device, and has been the focus of many potential energy storage applications, especially given its fairly small energy requirements.²²

3.3 Other Applications of Energy Storage

In addition to energy arbitrage and operating reserves, there are several other services that energy storage has provided or could provide in the current grid. Several of these applications are discussed below.

Transmission and Distribution

In addition to generation, storage can act as an alternative or supplement to new transmission and distribution (T&D). Distribution systems must be sized for peak demand; as demand grows, new systems (both lines and substations) must be installed, often only to meet the peak demand for a few hours per year. New distribution lines may be difficult or expensive to build, and can be avoided or deferred by deploying distributed storage located near the load (Nourai 2007). (Energy can be stored during off-peak periods when the distribution system is lightly loaded, and discharged during peak periods when the system may otherwise be overloaded.) Energy storage can also reduce the high line-loss rates that occur during peak demand (Nourai et al. 2008).

²⁰ PJM's capacity market (Reliability Pricing Model) data derived from <http://www.pjm.com/markets-and-operations/rpm.aspx>.

²¹ More recent data shows a greater range of value for contingency reserves. For example, in 2008, the average value for spinning reserves in NYISO was \$10.1 in the east and \$6.2 in the west, corresponding to as little as \$54/kW-yr. In the same year, the average price in ERCOT was \$27.1, corresponding to \$237/kW-yr. In 2009, these values fell substantially to \$36/kW-yr in NYISO west, and \$87/kW-yr in ERCOT.

²² Frequency regulation theoretically is a net zero energy service over relatively short time scales, meaning the energy capacity of the device can be much smaller than those providing operating reserves and energy arbitrage. Several markets in the United States have changed or have proposed to change their treatment of regulation to accommodate energy-limited storage technologies. Furthermore, it has been suggested that fast-responding storage devices could receive a greater value per unit of capacity actually bid, because they could actually reduce the amount of reserves needed. For example, "faster responsive resources can help to reduce California ISO's regulation procurement by up to 40% (on average)" and "California ISO may consider creating better market opportunities and incentives for fast responsive resources." (Makarov et al. 2008).

Black-Start

Black-start provides capacity and energy after a system failure. A black-start unit provides energy to help other units restart and provide a reference frequency for synchronization. Pumped hydro units have been used for this application.²³

Power Quality and Stability

Energy storage can be used to assist in a general class of services referred to as power quality and stability. Power quality refers to voltage spikes, sags, momentary outages, and harmonics. Storage devices are often used at customer load sites to buffer sensitive equipment against power quality issues. Electric power systems can also experience oscillations of frequency and voltage. Unless damped, these disturbances can limit the ability of utilities to transmit power and affect the stability and reliability of the entire system. System stability requires response times of less than a second, and can be met by a variety of devices including fast-responding energy storage.

End-Use/Remote Applications

Other applications for energy storage are at the end use. Storage can provide firm power for off-grid homes, but also can provide value when grid-tied through management of time-of-use rates, or demand charges in large commercial and industrial buildings. Energy storage also provides emergency and backup power for increased reliability. In many cases, end-use applications have analogous applications in the grid as a whole (and potentially compete with these applications). For example, using energy storage to time-shift end use is functionally equivalent to energy arbitrage, and a flatter load on the demand side reduces the potential need for load-leveling in central storage applications (and vice-versa). To be economic, end-use applications require time-varying prices and are extremely site-specific.

3.4 Summary of Energy Storage Applications in the Current Grid

Table 3.2 provides a summary of the various applications of energy storage commonly discussed in the literature. Each of these applications provides a potential value to a merchant storage operator in a restructured market or a source of cost reduction to the system.

²³ Large PHS units or other black-start generators must themselves be “black-started” and may use batteries or small generators for this purpose. Many transmission substations also use batteries partly to maintain reliability during power failures.

Table 3.2. Traditional Major Grid Applications of Energy Storage

Application	Description	System Benefits when Provided by Storage	Timescale of Operation
Load Leveling/ Arbitrage	Purchasing low-cost off-peak energy and selling it during periods of high prices.	Increases utilization of baseload power plants and decrease use of peaking plants. Can lower system fuel costs, and potentially reduce emissions if peaking units have low efficiency.	Response in minutes to hours. Discharge time of hours.
Firm Capacity	Provide reliable capacity to meet peak system demand.	Replace (or function as) peaking generators.	Must be able to discharge continuously for several hours or more.
Operating Reserves			
Regulation	Fast responding increase or decrease in generation (or load) to respond to random, unpredictable variations in demand.	Reduces use of partially loaded thermal generators, potentially reducing both fuel use and emissions.	Unit must be able to respond in seconds to minutes. Discharge time is typically minutes. Service is theoretically “net zero” energy over extended time periods.
Contingency Spinning Reserve ²⁴	Fast response increase in generation (or decrease load) to respond to a contingency such as a generator failure.	Same as regulation.	Unit must begin responding immediately and be fully responsive within 10 minutes. Must be able to hold output for 30 minutes to 2 hours depending on the market. Service is infrequently called. ²⁵
Replacement/ Supplemental	Units brought on-line to replace spinning units.	Limited. Replacement reserve is typically a low-value service.	Typical response time requirement of 30-60 minutes depending on market minutes. Discharge time may be several hours.

²⁴ Contingency reserves may be provided by both spinning and non-spinning units, depending on the market. The requirements for non-spinning reserves are the same except the resource does not need to “begin responding immediately.” Full response is still within 10 minutes.

²⁵ For example, in the PJM regional transmission organization (RTO) in 2008 (covering about 50 million people), synchronized reserves were called a total of 40 times with an average duration of 10 minutes. See <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>

Ramping/Load Following	Follow longer term (hourly) changes in electricity demand.	Reduces use of partially loaded thermal generators, potentially reducing both fuel use and emissions. Price is “embedded” in existing energy markets, but not explicitly valued, so somewhat difficult to capture.	Response time in minutes to hours. Discharge time may be minutes to hours.
T&D Replacement and Deferral	Reduce loading on T&D system during peak times.	Provides an alternative to expensive and potentially difficult to site transmission and distribution lines and substations. Distribution deferral is not captured in existing markets.	Response in minutes to hours. Discharge time of hours.
Black-Start	Units brought online to start system after a system-wide failure (blackout).	Limited. May replace conventional generators such as combustion turbines or diesel generators.	Response time requirement is several minutes to over an hour. Discharge time requirement may be several to many hours. ²⁶
End-Use Applications			
TOU Rates	Functionally the same as arbitrage, just at the customer site.	Same as arbitrage.	Same as arbitrage.
Demand Charge Reduction	Functionally the same as firm capacity, just at the customer site.	Same as firm capacity.	Same as firm capacity.
Backup Power/ UPS/Power Quality	Functionally the same as contingency reserve, just at the customer site.	Benefits are primarily to the customer.	Instantaneous response. Discharge time depends on level of reliability needed by customer.

²⁶ The black-start performance standard in PJM is 90 minutes to start, with an ability to run for 16 hours (PJM 2009a).

It should be noted that Table 3.2 does not include any dedicated renewables applications. Historical motivations for energy storage deployment were based on the challenges of meeting variations in demand using conventional thermal generators. Much of the current attention for energy storage is based on its potential application with renewable energy (primarily solar and wind). Energy storage is seen as a means to “firm” or “shape” the output from variable renewable generators. However, the actual need for storage to perform these roles has yet to be quantified. In addition, it is unclear whether the electric power industry must create entirely new “classes” of energy and capacity services to deal with the increased uncertainty and variability created by large-scale deployment of variable renewables. Determining the role of energy storage with renewables first requires examining the impacts of variable generators on the grid and how these impacts may require the use of various enabling technologies.

4 Impacts of Renewables on the Grid and the Role of Enabling Technologies

The introduction of variable renewables is now one of the primary drivers behind renewed interest in energy storage. A common claim is that renewables such as wind and solar are intermittent and unreliable, and require backup and firming to be useful in a utility system – energy produced by wind and solar should be “smoothed” or shifted to times when the wind is not blowing or the sun is not shining using energy storage. These statements are generally qualitative in nature and provide little insight into the actual role of renewables in the grid, (including their costs and benefits) or the potential use of energy storage or other enabling technologies.

To evaluate the actual role of energy storage in a grid with large amounts of variable renewable generation, we must first return to our previous discussion of the variability of electric demand, and how the conventional generators currently meet this demand. As discussed in Section 2, tremendous variation in daily demand is met by the constant up-and-down cycling of generators. In addition to this daily cycling, frequency regulation and contingency reserves are provided by partly loaded generators and responsive load.²⁷ Most of these “flexible” generators are hydro units, combustion turbines, some combined-cycle plants, and even large thermal generators, as well as the existing PHS.

Variable generation (VG)²⁸ will change how the existing power plant mix is operated, because its output is unlike conventional dispatchable generators. It is easiest to understand the impact of VG technologies on the grid by considering them as a source of demand reduction with unique temporal characteristics. Instead of considering wind or PV as a source of generation, they can be considered a reduction in load with conventional generators meeting the “residual load” of normal demand minus the electricity produced by renewable generators.

Figure 4.1 illustrates this framework for understanding the impacts of variable renewables. In this figure, renewable generation is subtracted from the normal load, showing the “residual” or net load that the utility would need to meet with conventional sources.²⁹ The benefits to the utility include reduced fuel use (and associated emissions)³⁰ and a somewhat reduced need for overall system capacity (this is relatively small for wind but can be significant for solar given its coincidence with load.)³¹ There are also four significant impacts that change how the system must be operated and affect costs.

²⁷ In some locations such as Texas, demand response typically provides half of the contingency reserve requirements. Other regions also use (or are evaluating) load to provide regulation.

²⁸ From this point on, variable renewable generators will be referred to as variable generation (VG) following NERC 2009.

²⁹ This figure uses ERCOT load data from 2005 along with 15 GW of spatially diverse simulated wind data from the same year. See Section 4.2 for more details about the data used.

³⁰ A reduction in demand from VG or load will reduce the total marginal cost of generation, which includes fuel, emissions costs, and variable O&M. This ignores any additional cost impacts of variability on the remaining generation fleet, which is discussed in the next section.

³¹ There are a number of other benefits provided by renewable energy sources such as reduced volatility of fuel prices. This work is not intended to be an analysis of the total benefits of renewables or VG.

First is the increased need for frequency regulation, because wind can increase the short-term variability of the net load (not illustrated on the chart).³² Second is the increase in the ramping rate, or the speed at which load-following units must increase and decrease output. The third impact is the uncertainty in the wind resource and resulting net load.³³ The final impact is the increase in overall ramping range – the difference between the daily minimum and maximum demand – and the associated reduction in minimum load, which can force baseload generators to reduce output; and in extreme cases, force the units to cycle off during periods of high wind output. Together, the increased variability of the net load requires a greater amount of flexibility and operating reserves in the system, with more ramping capability to meet both the predicted and unpredicted variability. The use of these variable and uncertain resources will require changes in the operation of the remaining system, and this will incur additional costs, typically referred to as integration costs.

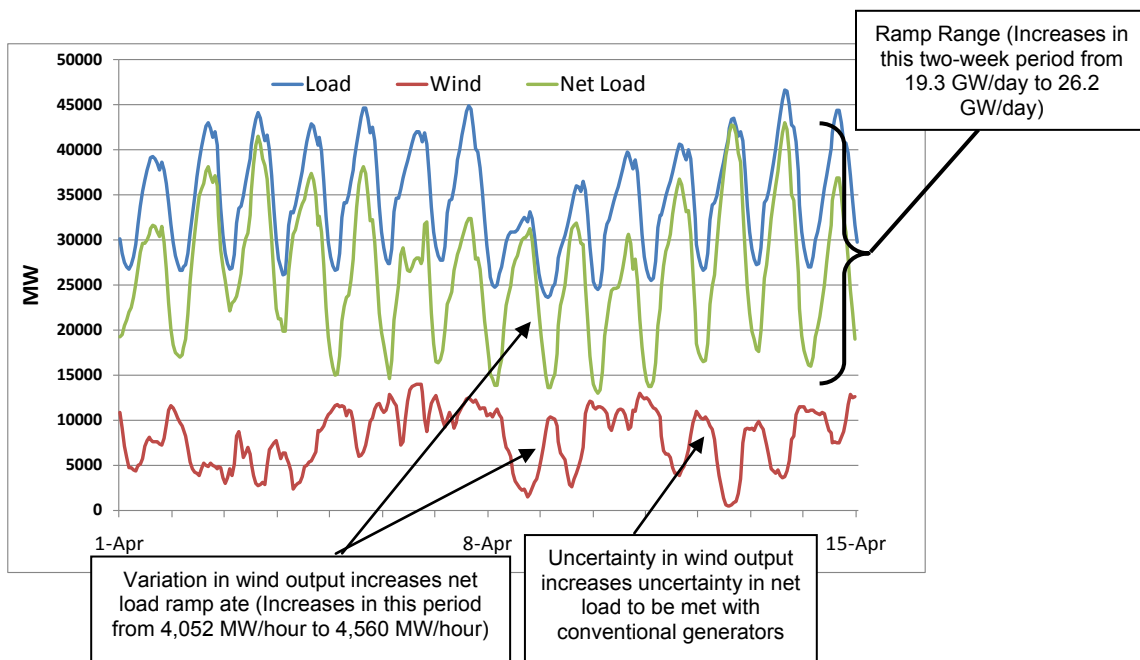


Figure 4.1. Impact of net load from increased use of renewable energy

³² As discussed later, the impact of short-term wind variability is often overstated, especially considering the benefits of spatial diversity. The impact on minute-to-minute regulation requirements is mitigated by aggregating large amounts of wind because individual wind plant variability is uncorrelated in the regulation time frame. Furthermore, the limited ability to forecast wind and use of persistence forecasts may be a major factor in increased short-term variability of the net load. Finally, newer wind turbines meeting “low-voltage ride-through” standards can add short-duration stability, and have the capability to provide frequency regulation to the grid.

³³ This is actually the combination of the uncertainty in load and the uncertainty in wind. As VG penetration increases, it begins to dominate the net load uncertainty.

4.1 Costs of Wind and Solar Integration from Previous Studies

Concerns about grid reliability and the cost impacts of wind have driven a large number of wind integration studies. These studies use utility simulation tools³⁴ and statistical analysis to model systems with and without wind and calculate the integration costs of wind.

The basic methodology behind these studies is to compare a base case without wind to a case with wind, evaluating technical impacts and costs. The studies calculate the additional costs of adding operating reserves as well as the other system changes needed to reliably address the increased uncertainty and variability associated with wind generation.

Table 4.1 provides examples of several integration studies from various parts of the United States. In these studies, integration costs are typically divided into three types, based on the timescales important to reliable and economic power system operation. These three types are the first three of the four impacts discussed previously:

Regulation – the increased costs that result from providing short-term ramping (seconds to minutes) resulting from wind deployment.

Load following – the increased costs that result from providing the hourly ramping requirements resulting from wind deployment.

Wind uncertainty – the increased costs that result from having a suboptimal mix of units online because of errors in the wind forecast. This is typically called unit commitment or scheduling cost because it involves costs associated with committing (turning on) too few or too many slow-starting, but lower operational-cost units than would have been committed if the wind forecast been more accurate.

³⁴ These tools have several names such as “production cost” or “security-constrained unit commitment and economic dispatch” models.

Table 4.1. Summary of Recent Wind Integration Cost Studies (DeCesaro et al. 2009)

Date	Study	Wind Capacity Penetration (%)	Regulation Cost (\$/MWh)	Load-Following Cost (\$/MWh)	Unit Commitment Cost (\$/MWh)	Other (\$/MWh)	Tot Oper. Cost Impact (\$/MWh)
2003	Xcel-UWIG	3.5	0	0.41	1.44	Na	1.85
2003	WE Energies	29	1.02	0.15	1.75	Na	2.92
2004	Xcel-MNDOC	15	0.23	na	4.37	Na	4.6
2005	PacifiCorp-2004	11	0	1.48	3.16	Na	4.64
2006	Calif. (multi-year) ^a	4	0.45	trace	trace	Na	0.45
2006	Xcel-PSCo ^b	15	0.2	na	3.32	1.45	4.97
2006	MN-MISO ^c	36	na	na	na	na	4.41
2007	Puget Sound Energy	12	na	na	na	na	6.94
2007	Arizona Pub. Service	15	0.37	2.65	1.06	na	4.08
2007	Avista Utilities ^d	30	1.43	4.4	3	na	8.84
2007	Idaho Power	20	na	na	na	na	7.92
2007	PacifiCorp-2007	18	na	1.1	4	na	5.1
2008	Xcel-PSCo ^e	20	na	na	na	na	8.56

^a Regulation costs represent 3-year average.

^b The Xcel/PSCO study also examine the cost of gas supply scheduling. Wind increases the uncertainty of gas requirements and may increase costs of gas supply contracts.

^c Highest over 3-year evaluation period. 30.7% capacity penetration corresponding to 25% energy penetration

^d Unit commitment includes cost of wind forecast error.

^e This integration cost reflects a \$10/MMBtu natural gas scenario. This cost is much higher than the integration cost calculated for Xcel-PSCO in 2006, in large measure due to the higher natural gas price: had the gas price from the 2006 study been used in the 2008 study, the integration cost would drop from \$8.56/MWh to \$5.13/MWh.

The overall cost impact of accommodating wind variability in these studies is typically less than \$5/MWh (0.5 cents/kWh), adding less than 10% to the cost of wind energy.³⁵ The majority of these costs appear to be a result of wind forecasting errors and uncertainty – resulting in “unit commitment” errors where too little or too much capacity is kept online. It is worth noting that wind forecasting is an area of active research, and these errors are expected to decrease in time, which could potentially lead to a corresponding decrease in unit commitment errors and associated costs.

The explanation for this relatively modest impact on costs is largely based on the already significant variation in normal load. The large amount of flexible generation already available to meet the variability in demand has the ability to respond to the greater variability caused by the large-scale deployment of wind. Furthermore, these studies have found significant benefits of spatial diversity – just because the wind isn’t blowing in one location, it may be in another. The combination of multiple wind sites tends to smooth out the aggregated wind generation in a system, which reduces the per-unit size of ramps and mitigates the range of flexibility required.³⁶

Far less work has been performed on the operational impacts of large-scale solar generation due largely to lower deployment rates compared to wind.³⁷ In addition, there is insufficient solar data available to estimate impacts on frequency regulation and ramping (Lew et al. 2009.) One study of PV on the Xcel Colorado utility system found integration costs of between \$3.51/MWh and \$7.14/MWh for a scenario examining 800 MW of solar in a 6,922 MW peaking system, with gas prices ranging from \$7.83 to \$11.83/MMBTU (EnerNex 2009). Additional studies are ongoing, but it will be some time until knowledge of solar’s impact on the grid and associated costs are understood to the degree of wind.³⁸

In reality, while these studies divide the costs into three main categories, the source of actual integration costs is largely associated with the fuel costs needed to provide the additional required reserves, along with some variable operations and maintenance costs. To provide regulation and load following, the additional variability requires that utilities run more flexible generators (such as gas-fired units instead of coal units, or simple-cycle turbines instead of combined-cycle turbines) to ensure that additional ramping requirements can be met. This was illustrated previously in Figure 2.3 where a

³⁵ This actually oversimplifies the situation. Some research indicates that these costs are not entirely integration costs but a modeling artifact of how the “base case” in these studies is actually simulated (Milligan and Kirby 2009).

³⁶ “Combining geographically diverse wind and solar resources into a single portfolio tends to reduce hourly and sub-hourly variations in real-time output. This would result in a more consistent level of output over a longer time frame, which could reduce the cost of wind integration” (Hurlbut 2009). For additional analysis of spatial diversity, see also Palmintier et al. 2008.

³⁷ In 2008, more than 8.5 GW of wind was installed in the United States, reaching a total capacity of about 25.3 GW by the end of the year (AWEA 2009). In the same year, 0.3 GW of solar PV was installed, reaching a total capacity of about 1 GW (Sherwood 2009).

³⁸ The impacts of CSP are largely unquantified as well. However, it is expected that the impact of CSP on short time scales will be significantly less than PV, because CSP has significant “thermal inertia” in the system that will minimize high-frequency ramping events. Furthermore, CSP has the potential advantage of utilizing high-efficiency thermal storage discussed in Section 5.

“nonoptimal” mix of generators was needed to provide the ability to adjust output in response to contingencies and other variations in demand. This combination of higher fuel costs and lower-efficiency units results in increased cost of fuel per unit of electricity generated as opposed to the “no-wind” cases.³⁹ Additional fuel costs occur from keeping units at part-load, ready to respond to the variability, or from more frequent unit starts. The costs associated with unit commitment or scheduling are also largely captured in increased fuel costs. Most large thermal generators must be scheduled several hours (or even days) in advance to be ready when needed. Ideally, utilities schedule and operate only as many plants as needed to meet energy and reserve requirements at each moment in time. If utilities over-schedule (turn on too many plants), they will have many plants running at part-load, and have incurred higher than needed start-up costs. So, if they under-predict the wind, they will commit and start up too many plants, which incurs greater fuel (and other) costs than needed if the wind and corresponding net load had been forecasted accurately. Conversely, if the wind forecast is too high and the net load is higher than expected, insufficient thermal generation may be committed to cover the unexpected shortfall in capacity. A worst-case scenario would be a partial blackout; but the likely result is the use of high-cost “quick-start” units in real-time, purchasing expensive energy from neighboring utilities (if available), or paying customers a premium to curtail load – all while lower cost units are sitting idle. An example of this is the ERCOT event of Feb. 26, 2008 (Ela and Kirby 2008). On this date, a combination of events – including a greater than predicted demand for energy, a forced outage of a conventional unit, the wind forecast not being given to the system operators, and a lower than expected wind output – resulted in too little capacity online to meet load. As a result, the ERCOT system needed to deploy high-cost quick-start units, as well as pay customers to curtail load through its “load acting as a resource” program.⁴⁰ All of this occurred while lower-cost units were idle because the combination of events was unanticipated.⁴¹

³⁹ It should be noted that these increased costs are associated with the “residual” part of the system that provides the load not met by VG. This is often a source of confusion and is sometimes interpreted as an increase in fuel use and emissions of the total system – implying that the additional reserve requirements of VG somehow actually increase fuel use and emissions of the system, or that VG has a net negative impact on emissions. This is not the case, and integration studies have universally concluded that any increase in fuel use associated with reserves for VG is much smaller than overall avoided fuel and emissions from displaced conventional generation.

⁴⁰ Customers with interruptible loads that can meet certain performance requirements may be qualified to provide operating reserves under the Load Acting as a Resource (LaaR) program. In eligible ancillary services (AS) markets, the value of the LaaR load reduction is equal to that of an increase in generation by a generating plant. See <http://www.ercot.com/services/programs/load/laar/>

⁴¹ This issue has important implications for the use of storage or any other device used to mitigate uncertainty. Energy storage, like any other generator, needs to be scheduled – a storage device used for load leveling may not be able to simultaneously provide hedging against under-forecasted wind, because it may already be discharging.

While the bulk of the costs associated with wind integration are due to fuel use, the increased cycling also increases wear and tear on generators, which imposes extra maintenance costs.⁴²

Results from wind integration studies almost universally come to the conclusion that at the penetrations studied to date (up to about 30% on an energy basis), the analyzed systems do not need additional energy storage to accommodate wind's variability and maintain reliable service.⁴³ In the studied systems, no new generation technologies are required; but there are some potentially significant operational changes needed to maintain the present level of reliability (along with significant transmission additions needed to exchange resources over larger areas).⁴⁴ However, they do not necessarily find the "cost optimal" solution, which may include energy storage or some alternative mix of generation to further reduce the cost of wind integration. Furthermore, these studies have not evaluated much higher penetration levels of RE, where additional system constraints may require additional enabling technologies such as energy storage.

4.2 Limiting Factors for Integration of Wind and Solar Energy

To date, integration studies in the United States have found that variable generation sources can be incorporated into the grid by changing operational practices to address the increased ramping requirements over various timescales. At higher penetrations (beyond those already studied), the required ramp ranges will increase, which adds additional costs and the need for fast-responding generation resources. However, there are additional constraints on the system that will present additional challenges. These constraints are based on the simple coincidence of renewable energy supply and demand for electricity, combined with the operational limits on generators providing baseload power and operating reserves. Of the four operational cost impacts listed in the beginning of Section 4 (regulation, load following, scheduling, and ramping range), only the first three present major quantifiable costs in U.S. studies as of the end of 2009. Yet, it is the fourth constraint that may present an economic upper limit on variable renewable penetration without the use of enabling technologies.⁴⁵

As discussed in Section 1, in current electric power systems, electricity is generated by two general types of generators: baseload generators, which run at nearly constant output; and load-following units (including both intermediate load and peaking plants), which meet the variation in demand as well as provide operating reserves. At current penetrations of wind and solar in the United States, and at the levels studied in most integration studies, wind and solar generation primarily displaces flexible load-following

⁴² A number of utilities have expressed the opinion that these costs are not well-captured in previous wind integration studies. This issue is discussed later in this report.

⁴³ This also explains why no significant new storage has been developed in the United States or Europe despite the 25 GW and 65 GW of wind development, respectively, as of the end of 2008 (EWEA 2009).

⁴⁴ The more recent U.S. studies of very high penetration (the Western Wind and Solar Integration Study and the Eastern Wind Integration Study) require power and energy exchanges over larger areas than typically occur in the existing system (Milligan et al. 2009a).

⁴⁵ One additional challenge in a high-VG grid is the potential decrease in mechanical inertia that helps maintain system frequency. This concern is not well understood and could be mitigated by a variety of technologies including improved controls on wind generators, or other sources of real or virtual inertia that could include energy storage. See, for example, Doherty et al. (forthcoming).

generators. Figures 4.2 and 4.3 illustrate this issue by providing the impacts of increasing amounts of wind generation in a simulated grid.⁴⁶ In Figure 4.2, wind provides 8.5 % of the energy in this four-day period and displaces the output from a mix of gas-fired units, which are already typically used to follow load. Because these generators are designed to vary output, they can do this with modest cost penalties as analyzed in the wind integration studies discussed previously.

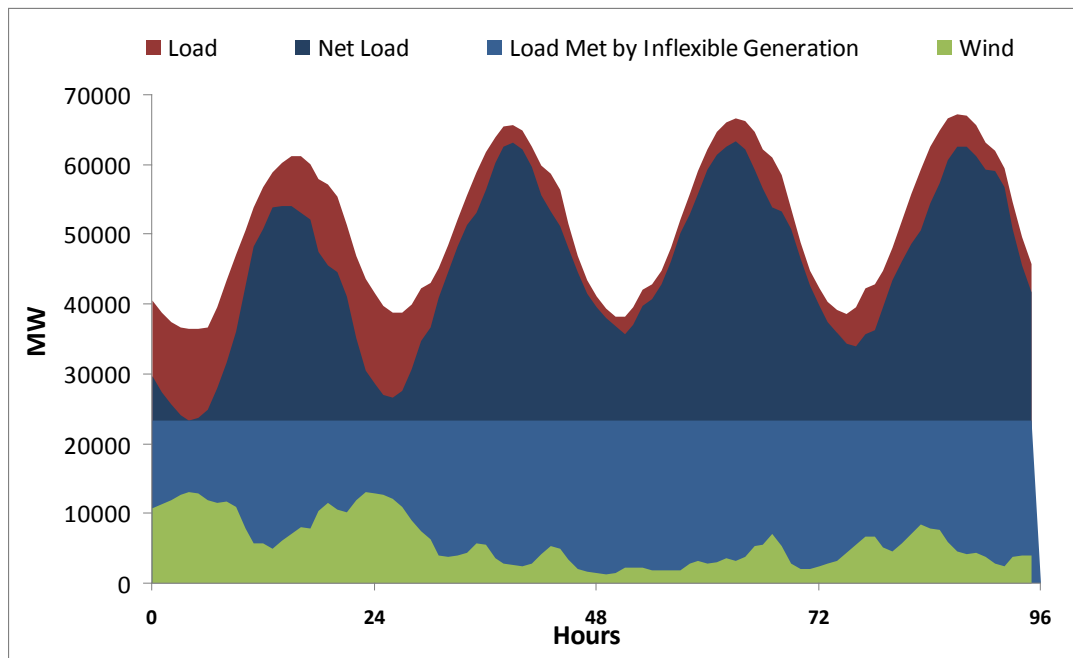


Figure 4.2. Dispatch with low VG penetration (wind providing 8.5% of load)

At higher penetration of RE, the ability of conventional generators to reduce output becomes an increasing concern. In Figure 4.3, wind now provides 16% of the total demand in this four-day period. Variable renewables begin to displace units that are traditionally not cycled, and the ability of these thermal generators to reduce output may become constrained. If the baseload generators cannot reduce output (and some other use cannot be found for this “excess generation”),⁴⁷ then wind energy will need to be curtailed – this occurs in the overnight periods in the first two days of this scenario.

⁴⁶ This simulation uses historical load data from ERCOT from 2005 and simulated wind data for the same year provided by AWS Truewinds. While the wind and load data is from ERCOT, the mix of generators (flexible and inflexible) is hypothetical and used only to illustrate the impact of VG. For additional discussion of the wind data, see GE Energy 2008.

⁴⁷ The alternative to curtailment is finding some alternative use for this energy through enabling techniques and technologies, which may include energy storage. These options are discussed in Section 5.

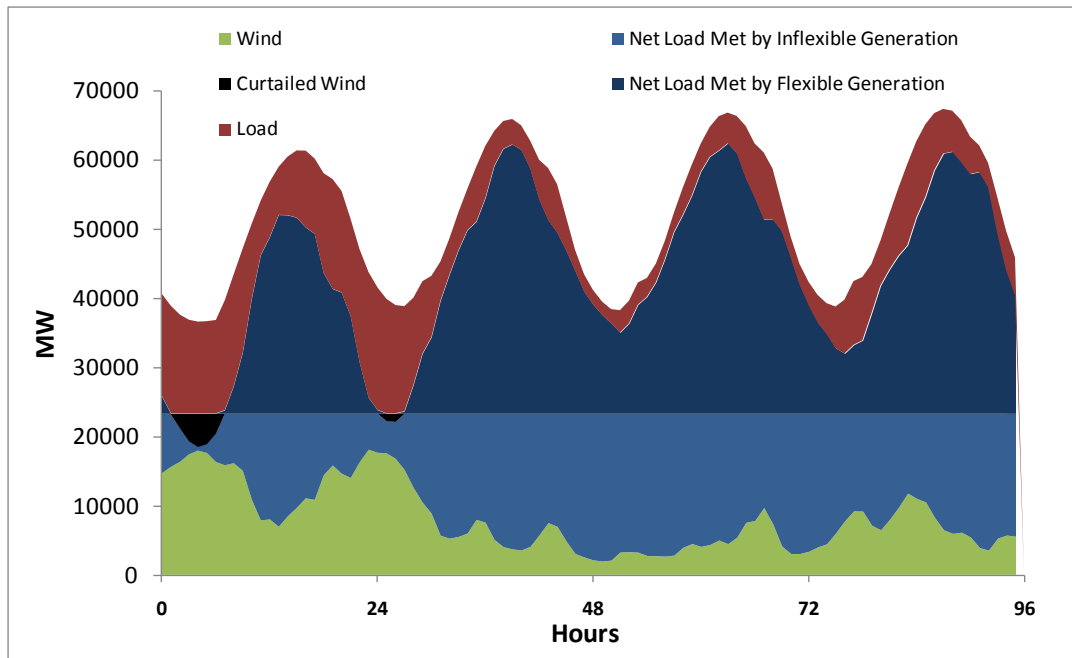


Figure 4.3. Dispatch with higher VG penetration (wind providing 16% of load)

Utilities in the United States have expressed concern about their systems “bottoming out” due to the minimum generation requirements during overnight hours, and being unable to accommodate more variable generation during these periods. Minimum generation constraints (and resulting wind curtailment) are already a real occurrence in the Danish power system, which has a large installed base of wind generation (Ackermann et al. 2009). Due to its reliance on combined heat and power electricity plants for district heating, the Danish system needs to keep many of its power plants running for heat. Large demand for heat sometimes occurs during cold, windy evenings, when electricity demand is low and wind generation is high. This combination sometimes results in an oversupply of generation, which forces curtailment of wind energy production. The need to curtail wind due to minimum load constraints has also been identified as an important component of future power systems in the United States.⁴⁸ Modern wind turbines can reliably curtail output, but this is largely undesirable because curtailment throws away cost-free and emissions-free energy.⁴⁹

The actual minimum load is a function of several factors including the mix of conventional generation, as well as the amount of reserves and the types of generators providing those reserves. The ability to cycle conventional units is both a technical and economic issue – there are technical limits to how much power plants of all types can be

⁴⁸ “During over-generation periods, when dispatchable generation plants are already operating at their minimum levels, the California ISO needs to have an ability to curtail wind generation on an as-needed basis.” (CAISO 2007)

⁴⁹ When curtailing output, wind or other VG can supply operating reserves. In some cases, the value of curtailed energy may actually exceed the value of energy, but the primary value of VG is displacing conventional generation. While Figure 4.3 curtails renewable generation, it not clear which plant “should” be curtailed. Ignoring operational constraints, from a strict economic sense, VG has a lower cost of energy and lower emissions; therefore, it should be curtailed last.

turned down. Large coal plants are often restricted to operating in the range of 50-100% of full capacity, but there is significant uncertainty about this limit. This is partly because utilities often have limited experience with cycling large coal plants, and have expressed concern about potentially excessive maintenance impacts⁵⁰ and even safety. It should be noted that because cycling costs are not universally captured in operational models, they may be ignored or underestimated in wind and solar integration studies.⁵¹ The impact of VG on power plant cycling is an active area of research, especially considering the evolving grid and introduction of more responsive generation.⁵²

It is unclear what changes in operation practices or generator modification utilities will need to make to cycle below their current minimum load points, which now typically occur during the early morning in spring. In a number of markets, energy prices have dropped below the actual variable (fuel) cost of producing electricity on a number of occasions. This indicates that power plant operators are willing to sell energy at a loss to avoid further reducing output. Figure 4.4 provides one example in the PJM market in 2002, where the price of electricity fell below the variable cost of generation (indicated by the dotted line)⁵³ from coal-fired units for about 100 hours during periods near the annual minimum. While not definitive, this indicates that under current operational practices, utilities in some systems may be uncomfortable or unable to cycle much below current minimum load levels.⁵⁴ In other locations, there may be a greater operating range if plant operators become more comfortable with cycling individual units. As an example, a recent wind integration study of the existing ERCOT system suggested the capability of the system to cycle down to a net load of about 13 GW, compared to the recent annual minimum loads of about 20 GW. However, this would require the coal fleet to cycle to below 50% of rated capacity, and gas plants to perform over an even greater cycling range (GE Energy 2008).

⁵⁰ “Cycling operations, that include on/off startup/shutdown operations, on-load cycling, and high frequency MW changes for automatic generation control (AGC), can be very damaging to power generation equipment.” However, these costs can be very difficult to quantify, especially isolating the additional costs associated with cycling above and beyond normal operations (Lefton et al. 2006).

⁵¹ Wind integration studies typically use proprietary software and data sets, and do not always state which costs are and are not included. However, in the Western Wind and Solar Integration Study (the highest penetration U.S. integration study as of 2009) the study states: “‘Wear and tear’ costs due to increased or harder cycling of units were not taken into account because these have not been adequately quantified.” (Lew et al. 2009).

⁵² A more detailed analysis of the relationship between wind penetration and plant cycling is provided by Troy et al. (forthcoming).

⁵³ During this year, the average price paid for coal in this region was about \$31/ton. With a typical heat rate of about 10,500 BTU, this translates into a variable cost of \$12-14/MWh. This cost can be observed in Figure 4.4 as the “floor” cluster of points at this level. Points below this level represent bids that are less than the cost of generation, but not necessarily uneconomic if the alternative is excessive cycling-induced maintenance or even a forced shutdown and very expensive restart of a coal generator.

⁵⁴ Minimum load points would be less of a constraint if power plants could be quickly shut down and started up at low costs. With the exception of certain peaking plants such as aeroderivative turbines and fast-starting reciprocating engines, most plants have minimum up-and-down times, and require several hours to restart (at considerable cost).

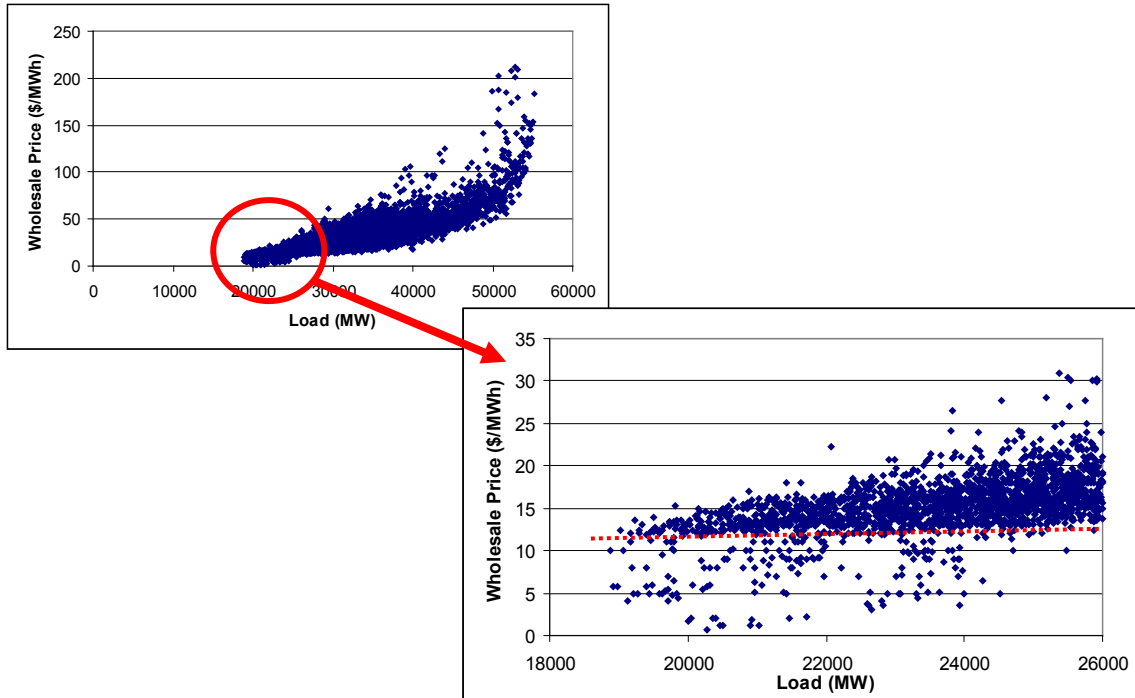


Figure 4.4. Relationship between price and load in PJM in 2002

Overall, the ability to accommodate a variable and uncertain net load has been described as a system's flexibility. System flexibility varies by system and over time as new technologies are developed and power plants are retired. In addition, VG deployment in the United States is still relatively small, and utilities have yet to evaluate the true cycling limits on conventional generators and their associated costs. Also, the additional reserve requirements due to VG at high penetration are still uncertain. As a result, it is not possible to precisely estimate the costs of VG integration or the amount of curtailment at very high penetration; it is also difficult to define with certainty the value of energy storage or other enabling technologies. It is clear, however, that substantial increase in the penetration of wind energy without storage will require changes in grid operation to reduce curtailment.

Figure 4.5 illustrates the fraction of a system's peak load derived from inflexible units as a function of the minimum load point. This is also expressed more generally as the system's "flexibility factor," which is defined as the fraction below the annual peak to which conventional generators can cycle (Denholm and Margolis 2007a and 2007b). In the current grid, the annual minimum load point is typically 30%-40% of annual peak load (or a flexibility factor of 60%-70%). If units cannot be cycled below this point, they will provide 55%-70% of a system's energy; and even with storage, this level of inflexibility leaves only 30%-40% of a system's energy for variable resources. One of the major conclusions of wind integration studies looking at higher penetrations is that

minimum load points will need to be lowered substantially below their current annual minimums.⁵⁵

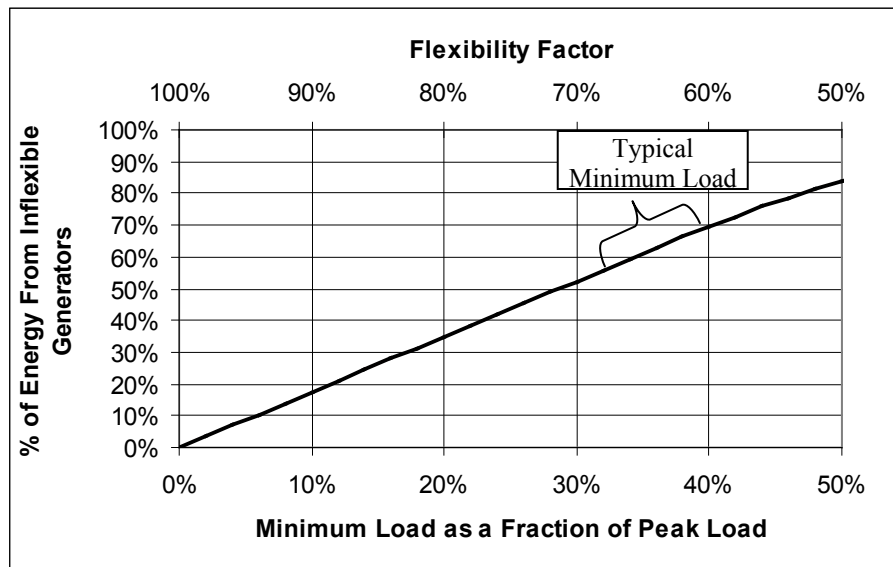


Figure 4.5. Contribution from inflexible generation

Alternatively, it is possible to evaluate the relationship between system flexibility and large-scale penetration of VG, both with and without energy storage or other enabling technologies. Figure 4.6 shows an example of how flexibility affects the potential curtailment of wind and solar energy when deployed without storage. These two charts superimpose load data in ERCOT from 2005 with a spatially diverse set of simulated wind and solar data from the same year.^{56,57} The simulation places 19 GW of wind and 11 GW of solar (representing an 80%/20% mix of wind and solar on an energy basis) into the 2005 ERCOT system, which had a peak demand of 60.3 GW. In the left chart, the system is assumed to be unable to cycle below the 2005 minimum point of 21 GW, resulting in substantial VG curtailment. In this simulation, wind and solar provide 20% of the grid's annual energy, and 21% of the total renewable energy production is curtailed. The right graph shows the result of increasing flexibility, allowing for a minimum load point of 13 GW. Curtailment has been reduced to less than 3%, and the same amount of variable renewables now provides about 25% of the system's annual energy.

⁵⁵ This is noted in previous wind integration studies such as the ERCOT study (GE 2008), and the more recent Eastern and Western Interconnect studies. "As the penetration of wind and solar increase, the impact on base-load coal increases, becoming very challenging at the 30% penetration." (Milligan et al. 2009b).

⁵⁶ Historically, many estimates of the limits of wind penetration have used data from a single or very small set of wind power plants, and often a small balancing area. Without spatial diversity of resource and load, this leads to both excessive ramp rates and excessive curtailment.

⁵⁷ The data set is the same as from Figures 4.2 and 4.3, with solar data derived from the National Solar Radiation Database. See Denholm and Margolis 2008 for additional details. The data was processed using the REFlex Model, which compares hourly electricity demand with VG supply and calculates curtailments as a function of system flexibility based on minimum load constraints. The model is described in more detail in Denholm and Margolis 2007a and 2007b.

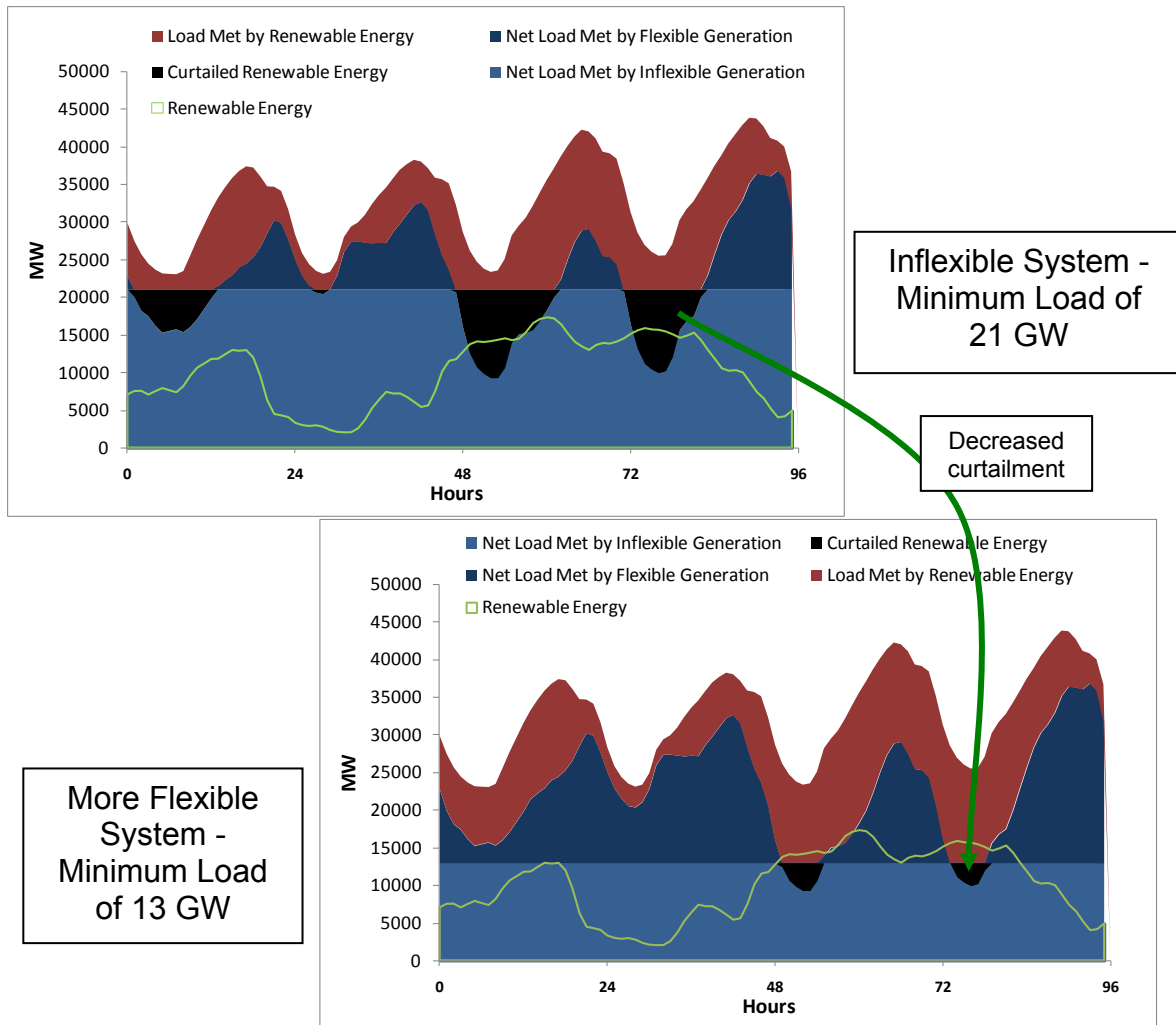


Figure 4.6. Effect of decreasing minimum load point on increased use of RE

These results can be evaluated more generally by examining the amount of curtailment that will result without energy storage as a function of system flexibility. Figure 4.7 shows example results, with three different minimum load/flexibility factors. The first curve illustrates the curtailment that would result if the system could not cycle below its 2005 annual minimum load of 21 GW. The second curve uses a minimum load of 12 GW, which corresponds roughly to the assumptions used in the 2008 ERCOT wind study (GE 2008). The third curve corresponds to a 6 GW minimum load, which largely eliminates baseload units from the generation mix, replacing them with more flexible units.⁵⁸

⁵⁸ It should be noted that significant changes in the generation mix and corresponding changes in system flexibility could result from CO₂ emissions constraints. Increased cost of carbon could motivate greater use of natural gas generation, and reduce use of coal, both of which would tend to increase system flexibility, and allow greater economic use of VG. This, in turn, would decrease fuel use and the capacity factor of thermal generators, which would also tend to increase the use of gas-fired generation and decrease the use of coal as the economic optimal mix of generation. For additional discussion, see Lamont 2008.

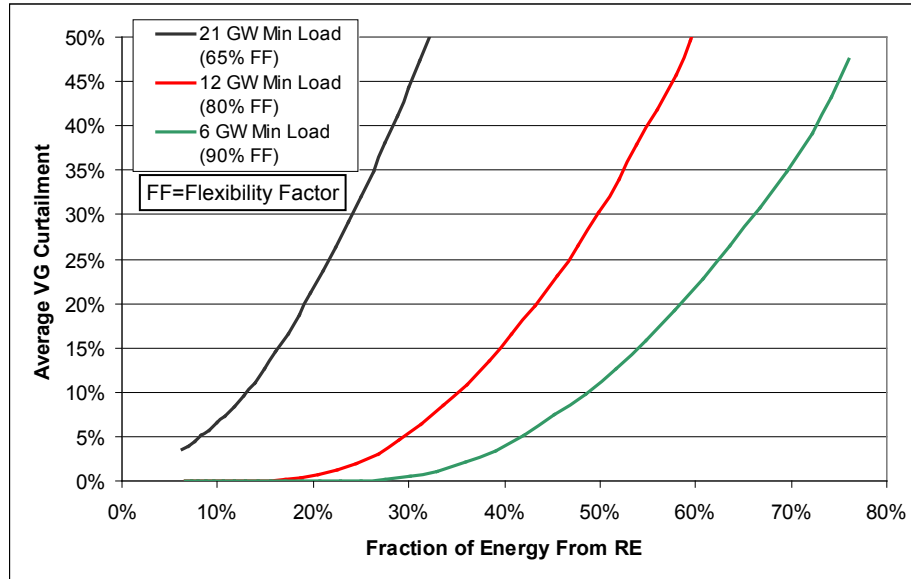


Figure 4.7. Average curtailment rate as a function of VG penetration for different flexibilities in ERCOT

Figure 4.7 somewhat obscures the fact that at the margin, curtailment rates can be very high. Figure 4.8 illustrates the marginal curtailment rate, or the curtailment rate of each incremental unit of VG installed in the system. For example, in the 12 GW minimum load curve, the average curtailment rate (Figure 4.7) when VG is providing 25% of the system's electricity demand is less than 3%, which means that less than 3% of all the VG at this penetration level is curtailed. However, the last unit of energy installed to get to this 25% point has a curtailment rate of more than 10%, as illustrated in Figure 4.8.

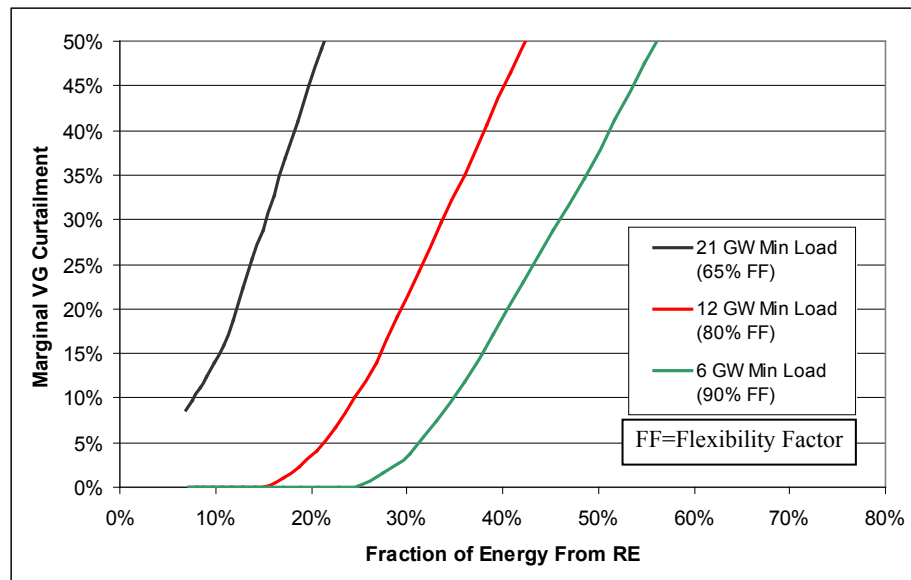


Figure 4.8. Marginal curtailment rate as a function of VG penetration for different system flexibilities in ERCOT (marginal curtailment is defined as the percentage curtailed as a function of the incremental penetration)

Curtailment increases the cost of the VG that is actually used, because curtailment reduces the net capacity factor of the wind and solar generators. Figure 4.9 shows how the effective cost of VG increases due to curtailment. Costs are illustrated in relative terms – a generator with no curtailment has a base cost of 1, which increases with a scale factor equal to $(1/(1-\text{curtailment rate}))$.

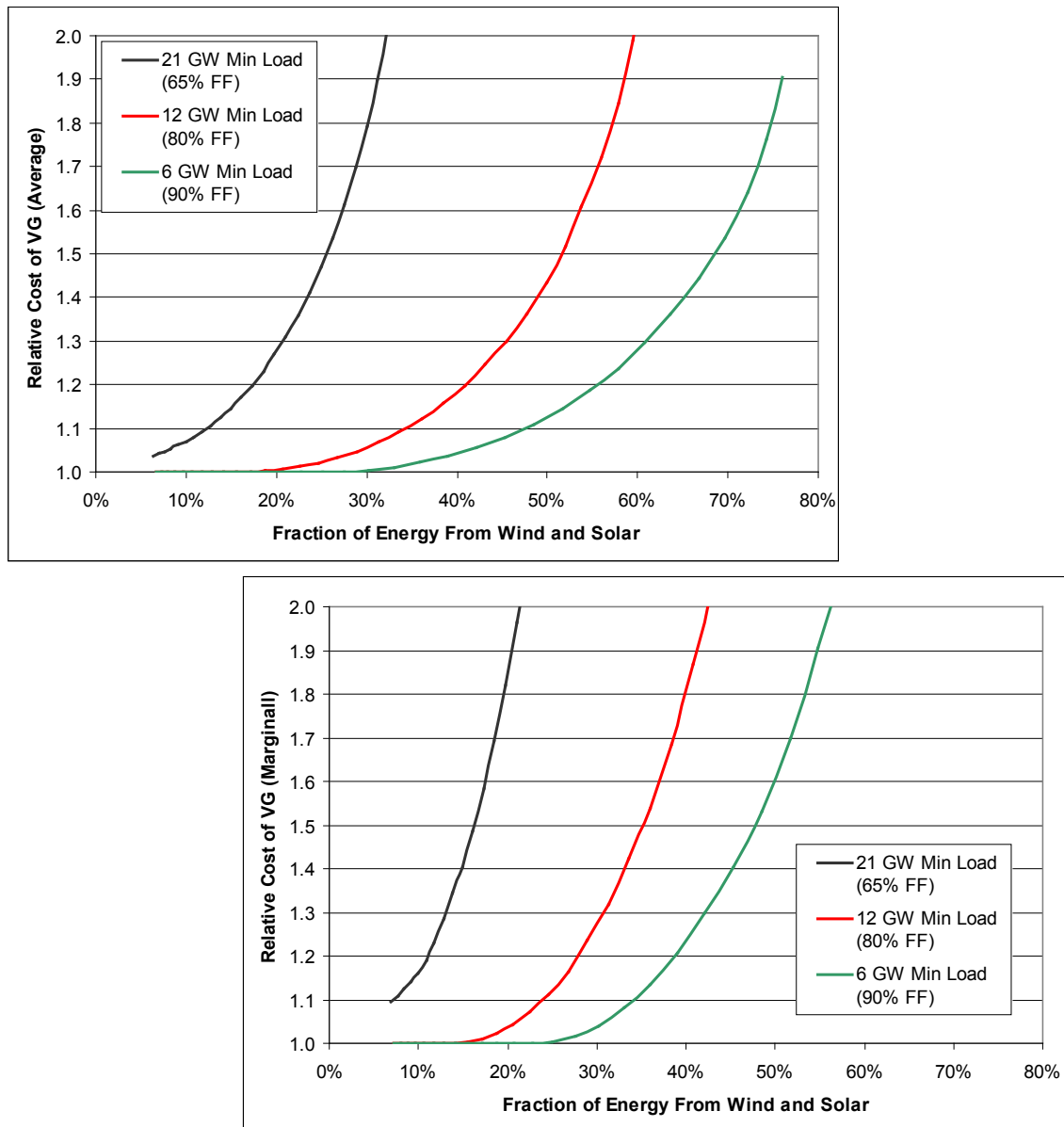


Figure 4.9. Relative cost of VG – average (top chart) and marginal (bottom chart) – as a function of VG penetration for different system flexibilities in ERCOT

This example can be compared to the results of the previous U.S. wind integration studies that find very little curtailment up to about 20% on an energy basis, due to the existing grid flexibility. Beyond this level (up to about 30%), curtailment increases without significant operational changes (Corbus et al. 2009). In the United States, penetrations of VG beyond 30% have yet to be extensively studied; however, the examples in this

section suggest curtailment rates will continue to rise substantially without a significant increase in system flexibility or deployment of other enabling technologies such as energy storage.

The results in Figure 4.9 apply to only a specific mix of VG – and a single system – so they cannot be applied generally. However, they do illustrate the trends that may limit the contribution of VG without enabling technologies. Ultimately, the cost of curtailment must be compared to alternatives such as the cost of storage or other enabling technologies, illustrated in Figure 4.10 and discussed in more detail in Section 5.⁵⁹

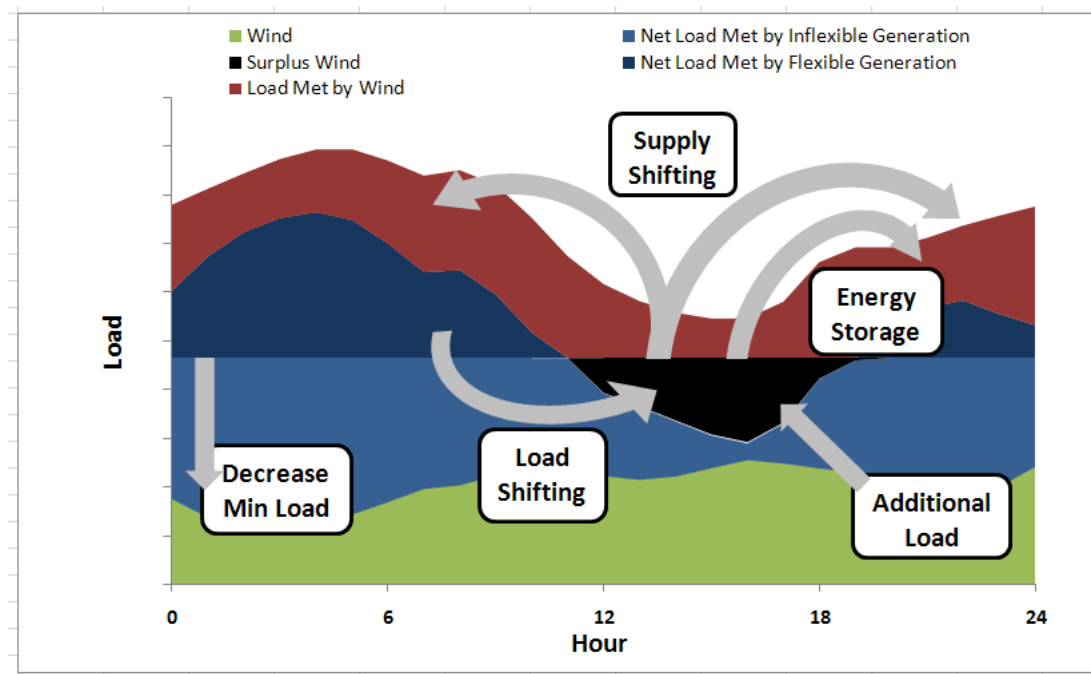


Figure 4.10. Option for increasing the use of VG by decreasing curtailment

Storage provides one solution to avoiding curtailment by absorbing otherwise unusable generation and moving it to times of high net system load (where net load is defined as normal load minus VG). The additional flexibility storage provides is also important. Storage can provide operating reserves, which reduces the need for partially loaded thermal generators that may restrict the contribution of VG. Finally, by providing firm capacity and energy derived from VG sources, storage can effectively replace baseload generation, which reduces the minimum loading limitations.

Figure 4.11 illustrates how the curtailment rate can be reduced by introducing energy storage.⁶⁰ The base case (no storage) is identical to Figure 4.7 with a 12 GW minimum

⁵⁹ The large number of options available for increasing the penetration of RE is one of the reasons why the question of when storage becomes necessary is very difficult to answer. There is less of a technical limit than an economic one that depends on a large number of factors such as the cost of storage compared to a vast array of alternatives.

⁶⁰ The data and methods used for this analysis are the same as before, using the REFlex model to place otherwise curtailed energy into storage and using that stored energy at a later time (Denholm and Margolis 2007b).

load (or an 80% flexibility factor). In addition, a storage device with 5% of the system's power capacity (or 3 GW in a 60 GW peaking system), 20 hours of energy capacity, and a 75% round-trip efficiency is introduced. If this device is used only to absorb otherwise unusable energy, the curtailment rate is reduced substantially. For example, when VG is providing 50% of the system's energy, about 30% of the VG is curtailed without storage, and about 25% with the 3 GW of storage. This includes the additional losses that occur in the storage process. The device's ability to replace firm capacity and potentially reduce the minimum load constraint further reduces curtailment. Adding the ability to reduce the minimum load by 50% of the device's capacity (or about 1.5 GW) reduces curtailment further – in the 50% VG case, the curtailment rate now drops from 30% without storage to 20% of the total VG.⁶¹

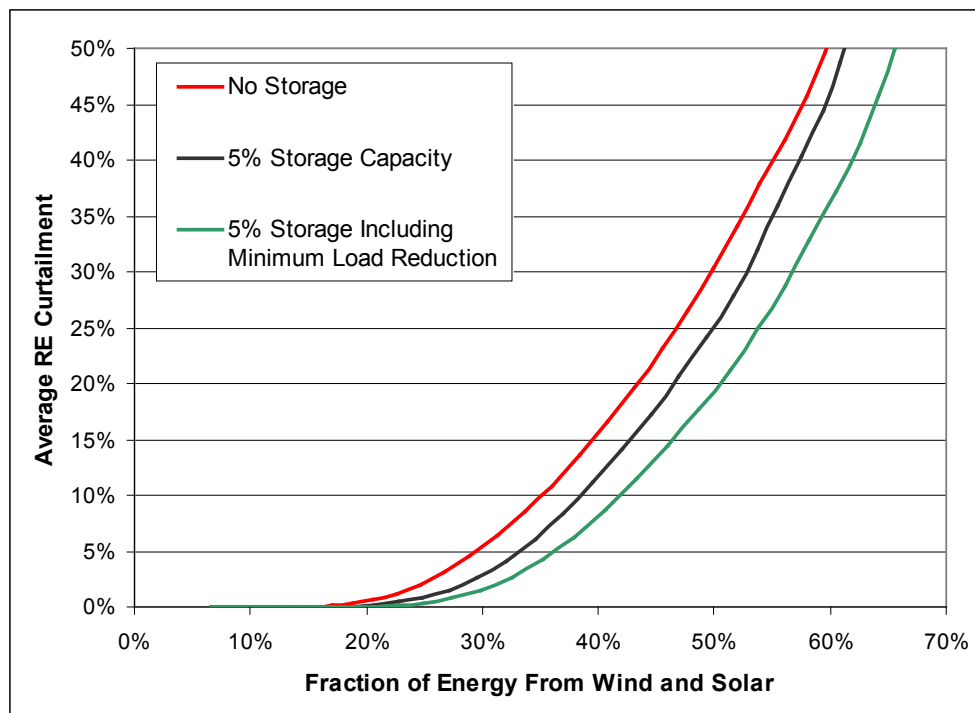


Figure 4.11. Reduction of curtailment resulting from addition of energy storage

While storage provides one solution to the mismatch of VG supply and normal demand, there are a variety of options for increasing the use of VG in the grid. Any evaluation of energy storage should consider the many alternative technologies that can increase grid flexibility and enable VG renewables.

⁶¹ Alternatively, for a given amount of allowed curtailment, the contribution of VG increases with the addition of storage. In the case illustrated in Figure 4.11, a maximum VG curtailment of 10% allows VG to provide about 35% of the total electricity demand. Adding energy storage (with its ability to reduce the minimum load) increases the contribution of VG (for the same amount of allowable curtailment) to about 42% of total demand.

5 Storage and Flexibility Options for Renewables-Driven Grid Applications

The previous section indicates that at high penetration of VG, fundamental changes to the grid may be required to accommodate the increased variability of net load and the limited coincidence of VG supply and normal electricity demand. A number of techniques and technologies – described as flexibility resources – have been proposed to accommodate the impacts of VG and ensure the generation mix matches the net-load requirement.

5.1 The Flexibility Supply Curve

Energy storage is one of many technologies proposed to increase grid flexibility and enable greater use of VG. This set of technologies has been described in terms of a flexibility supply curve that can provide responsive energy over various timescales. The flexibility supply curve is conceptually similar to other resource supply curves where (ideally) the lowest-cost resources are used until they are exhausted, then the next (higher-cost) resource is deployed. The analysis in Section 4, for example, was restricted to ERCOT, and did not consider the opportunity to exchange wind and solar energy with surrounding areas by building interconnections with the other U.S. grids. It also did not consider the ability to shift load by incentivizing customers to use less electricity when VG output is low. Overall, utilities have many “flexibility” options for incorporating greater amounts of VG into the grid, many of which may cost less than using energy storage. Figure 5.1 provides a conceptual supply curve including some of these options.

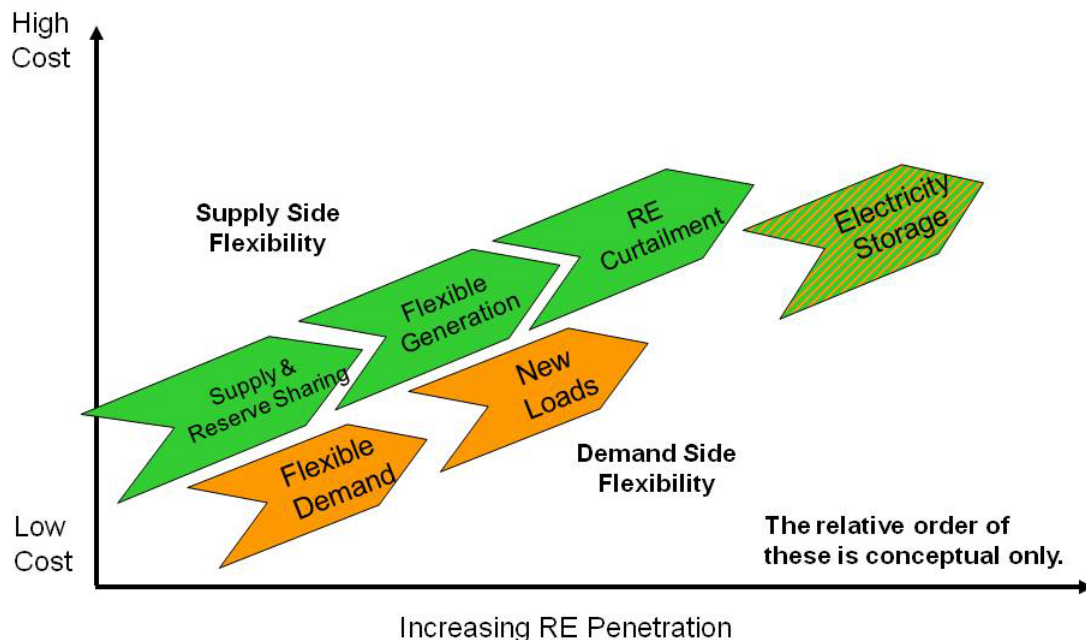


Figure 5.1. Flexibility supply curve⁶²

⁶² Based on an original by Nickell 2008. While the figure hypothesizes an order of the supply curve, the actual costs and availability of the individual components are conjectural.

Overall, there are two general “types” of flexibility required by variable sources and offered by technologies in this curve. The first can be described as ramping flexibility, or the ability to follow the variation in net load (in the second-to-minute timescale needed for frequency regulation, or the minutes-to-hours timescale needed for load following and forecast error.) This flexibility is the primary requirement at low penetration, as discussed in Section 4.2. The second type of flexibility is energy flexibility, or the ability to increase the coincidence of VG supply with demand for electricity services, which is described in Section 4.3. A description of several of the sources of flexibility is provided below.

- a.) **Supply and Reserve Sharing.** This includes the sharing of renewable and conventional supply, operating reserves, and net loads through markets or other mechanisms that effectively increase the area over which supply and demand is balanced.⁶³ Greater aggregation of loads and reserves has historically been one of the least-cost methods of dealing with demand variability, especially because it often requires operational changes and relatively little new physical infrastructure.⁶⁴ It may also require transmission development to increase the spatial diversity of VR resources.
- b.) **Flexible Generation.** This includes deploying new, more flexible conventional generators as well as increasing flexibility of existing generators. This can be accomplished by modifying equipment and operational practices⁶⁵ to increase the load-following, ramping rate, and ramping range of the grid. This also includes introducing new generators that can be brought online quickly to respond to forecast errors.⁶⁶ This may also require increased use of natural gas storage to increase use of flexible gas turbines and decrease contractual penalties for forecast errors in natural gas use (Zavadil 2006). Another source of flexible generation is improved use of existing storage and hydro assets.
- c.) **Demand Flexibility.** This includes introducing market or other mechanisms to allow a greater fraction of the load to respond to price variations and provide ancillary services. Responsive demand can provide flexibility over multiple timescales by curtailing demand for short periods or shifting load over several hours. Many of these technologies and processes have been described in terms

⁶³ “Larger markets and balancing areas that are a central feature of ISOs and RTOs can improve the physical conditions needed to integrate large amounts of wind energy. ISOs and RTOs, with their day-ahead and real-time markets, large geographies to aggregate diverse wind resources, large loads to aggregate with wind, large generation pools that tap conventional generator flexibility... offer the best environments for wind generation to develop.” (Milligan et al. 2009b).

⁶⁴ This includes introducing sub-hourly markets that allow systems faster response to variability. Large ISOs with 5-minute markets typically have substantially lower wind integration costs.

⁶⁵ This could include scheduling generators over shorter time periods, and using sub-hourly wind forecasts instead of “persistence” forecasts that may actually contribute to short-term scheduling errors and increase regulation requirements.

⁶⁶ “Extensive changes will be required in the type of new generation built in the state: new units must have greater operating flexibility to start up and shut down without long delays; they must be able to operate at lower minimum loading levels; and they must have faster ramping capability and regulation capability” (CAISO 2007). Examples of more responsive generators include certain aeroderivative gas turbines and reciprocating engines. For additional discussion of flexible generators, see Northwest Power and Conservation Council 2009.

of a “smart grid” and will require regulatory and policy changes in addition to new technologies. In many locations in the United States, demand is increasingly used as a source of grid services.⁶⁷

- d.) **VG Curtailment.** Overbuilding VG may result in curtailment of low-value springtime generation, but would allow for a greater overall VG contribution. (This is functionally equivalent to cycling baseload generators in the spring.) Furthermore, curtailed VG provides additional benefits, because it provides a source of operating reserves and potentially allows for de-commitment of thermal units that typically provide these services.
- e.) **New Loads.** New controllable loads can be added to absorb otherwise unusable VG. Examples include space and process heating, which currently use fossil fuels. Another possibility is fuel production such as hydrogen via electrolysis or shale oil heating. Electrification of transportation using electric vehicles or plug-in hybrid vehicles is also a potential large-scale application. This may also include electric vehicles providing regulation and contingency reserves with or without the use of vehicle to grid (V2G).
- f.) **Electricity Storage.** Electricity storage encompasses a large number of technologies discussed in Section 5.2

The general classes of flexibility resources listed above represent dozens or even hundreds of individual technologies, each with a potential contribution to increasing grid flexibility. The cost and availability of many flexibility resources has yet to be quantified, and there are a variety of regulatory barriers to completely deploying many flexibility options such as demand response.

The cost of storage needs to be compared to the alternatives – this includes the efficiency losses in the storage process that may be avoided by using other enabling technologies. There are, of course, limits to each option on the curve; and the benefits of spatial diversity and demand response are limited because the VG supply cannot be expected to exactly match the demand for electricity services on the multiple timescales. Because of this, electricity storage is considered a potentially important step on the flexibility supply curve when lower-cost options are saturated or otherwise unavailable.

5.2 Deployment and Operational Balancing of Renewable Energy – Individual Plant Storage vs. Power System Storage

The previous section suggests that incorporating increased levels of VG most efficiently will require a variety of flexibility options. Likewise, the most efficient operation and location of flexibility options – including storage – must be considered. While flexibility resources can be considered renewable enabling technologies, their historical application has been to benefit the grid as a whole. It is often suggested that energy storage be co-located with, and operationally tied to, the output of individual VG facilities. However, this is not how the current system balances the large variability in net demand.

⁶⁷ As an example, ERCOT currently obtains half of its spinning reserve requirements from responsive load, and the ERCOT event of February 2008 discussed previously is an example of an application of load as a source of “up” ramping, used to meet demand until conventional generators could be started and dispatched.

Furthermore, the services needed to address variability and uncertainty are generally the same services that storage currently provides to the grid. Table 5.1 lists several renewable-specific applications that have been proposed (EPRI 2004). As an example, one potential renewable-specific application of storage is “time-shifting” of wind from periods of low demand to periods of high demand. However, this application is fundamentally the same as energy arbitrage, and the benefits of this application are greatest when the energy storage operator can choose from all of the generators in a system, and store energy when the cost is lowest, instead of storing only wind generation.

Table 5.1. Dedicated Renewable Applications of Energy Storage and Their Whole-Grid Counterpart

RE Specific Application	“Whole Grid” Application
Transmission Curtailment	Transmission Deferral
Time Shifting	Load Leveling/Arbitrage
Forecast Hedging	Forecast Error
Frequency Support	Frequency Regulation
Fluctuation Suppression	Transient Stability

Despite the attractiveness of a smoothed and shifted output from each generator, this approach results in a significant decrease in the efficiency of the entire system, and eliminates the benefits of resource aggregation. For example, demand of any individual electricity consumer can be very irregular, with rapid unpredictable ramps. Distributed energy storage could be used to smooth these individual demands. However, this would result in storage devices being charged in one location, while simultaneously discharged in another, wasting both the cost of storage devices and the losses in the storage process. The aggregated net demand of many individual consumers is considerably smoother, and would require much less storage to “flatten” if desirable. Likewise, operational integration between energy storage and any individual or groups of VG would be nonoptimal and likely result in simultaneous charging and discharging. By aggregating the entire net load of a system, including all loads and VG supply, storage or other flexibility options can be deployed at the lowest cost and greatest efficiency.⁶⁸ This is especially the case when spatial diversity substantially reduces variability over multiple timescales.

There are some exceptions when there are benefits of operationally combining VG and energy storage, typically through co-location and sharing of certain high-cost components. The best example is integrating thermal storage into a concentrating solar power (CSP) plant; another example is sharing power electronics in a distributed PV/battery system.

There are several other applications where co-location of VG and storage may make sense. Wind plants placed in areas of weak transmission can potentially introduce power quality and stability issues, and storage can be a mitigating technology; however,

⁶⁸ In effect, combining individual VG and storage is essentially the creation of very small balancing areas. This is actually the opposite of how the grid is evolving, with the creation of larger balancing areas and the use of reserve sharing agreements across utilities. Balancing individual VG would dramatically increase reserve requirements and would incur much greater costs than at the system level.

improved power electronics in modern wind turbines may be a lower-cost alternative. Finally, combining wind and energy storage has been proposed as an alternative (or supplement) to developing new transmission capacity. Increased deployment of wind energy will require substantial new transmission, and storage co-located with remote wind resources can help decrease the need for new transmission.⁶⁹ This has been proposed to relieve congestion in the ERCOT grid, for example, where the state's best wind resources are located largely in the sparsely populated western part of the state, and transmission capacity is limited (Desai et al. 2003). Despite these potential applications, the majority of storage deployed in the grid will likely be a shared resource, which will benefit the entire system and not just a single generator or load (Smith et al. 2007). Just as loads are balanced in aggregate, the net load in the future grid – after all VG sources are included – will be balanced by a mix of conventional generation, plus flexibility options that include energy storage.

5.3 Energy Storage Technologies and Applications

This section provides a brief overview of commercially available energy storage technologies. It is not intended to be a comprehensive discussion, because there are a large number of sources available that discuss the technical performance, current applications, vendors, and costs in detail. A number of more comprehensive reviews of energy storage technologies are provided in the Bibliography.

The choice of an energy storage device depends on its application in either the current grid or in the renewables/VG-driven grid; these applications are largely determined by the length of discharge. Energy storage applications are often divided into three categories, based on the length of discharge. Table 5.2 indicates the three regimes of energy storage applications commonly discussed.

Table 5.2. Three Classes of Energy Storage

Common Name	Example Applications	Discharge Time Required
Power Quality	Transient Stability, Frequency Regulation	Seconds to Minutes
Bridging Power	Contingency Reserves, Ramping	Minutes to ~1 hour
Energy Management	Load Leveling, Firm Capacity, T&D Deferral	Hours

The first two categories of energy storage applications in Table 5.2 correspond to a range of ramping and ancillary services, but do not typically require continuous discharge for extended periods of time. In the case of renewables-driven applications, this could require discharge times of up to about an hour to allow fast-start thermal generators to come online in response to forecast errors. (Bridging power typically refers to the ability of a

⁶⁹ Use of dedicated long-distance transmission for wind or solar will be limited by the relatively low capacity factor of the resource. Storage could increase line-loading and help reduce curtailment due to transmission constraints. For additional discussion, see Denholm and Sioshansi 2009.

storage device to “bridge” the gap from one energy source to another.)⁷⁰ The third category (energy management) corresponds to energy flexibility, or the ability to shift bulk energy over periods of several hours or more.

The references in the Bibliography provide a number of assessments and charts with estimates of technical performance and costs. Figure 5.2 provides one example of the range of technologies available for these three classes of services, and shows that many technologies can provide services across various timescales.

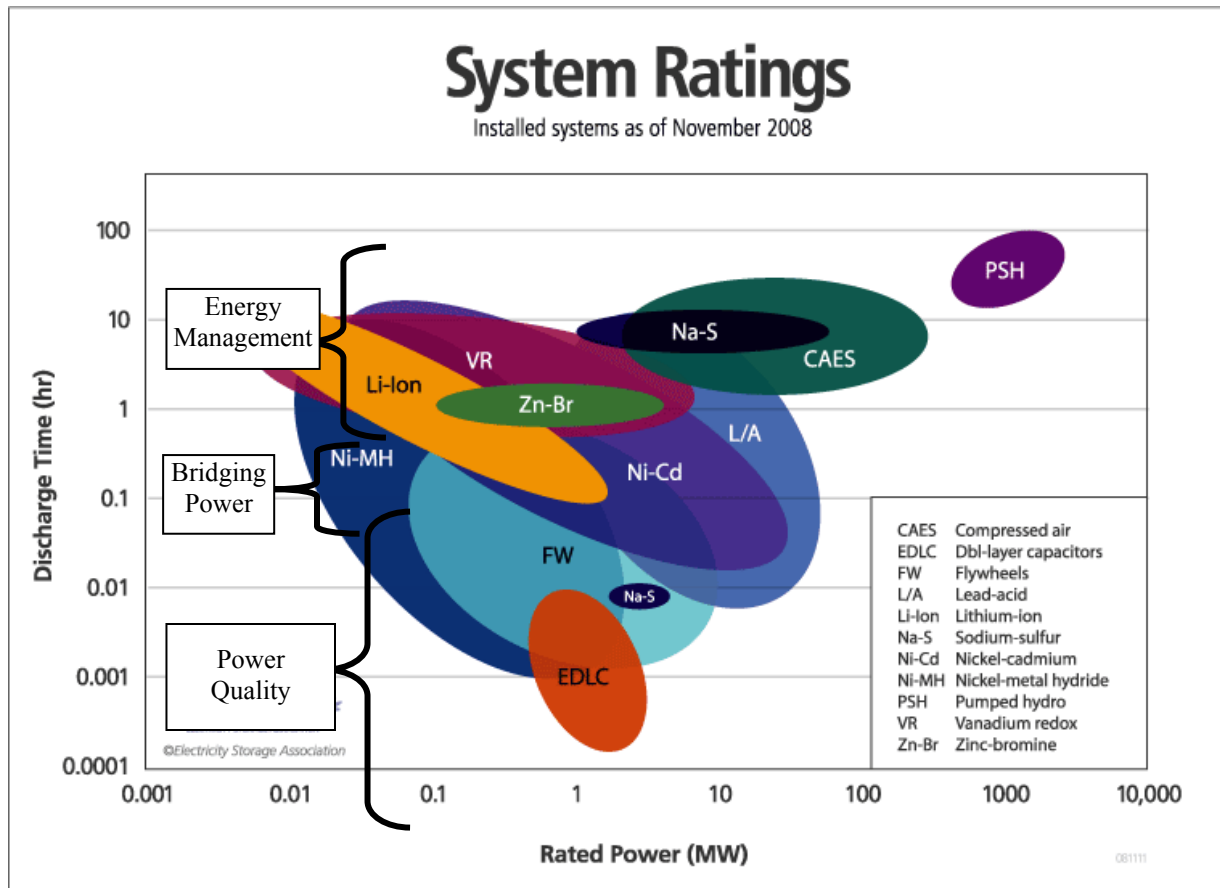


Figure 5.2. Energy storage applications and technologies⁷¹

⁷⁰ This often refers to the time it takes after a power failure for an isolated system to switch from the grid to a backup generator. However, this term may also be useful to describe the ability to address forecast errors and bring up standby generators during times of unforeseen decreases in wind or conventional generation.

⁷¹ This chart represents technologies actually deployed or proposed as of November 2008. It does not include a number of pre-commercial products or represent the total range of applications. For example, most of the batteries listed could be scaled up in either energy or power capacity, while at least 1 CAES plant of greater than 1,000 MW has been proposed. Alternatively, PSH plants of less than 50 MW have been constructed (ESA 2009).

It should be noted that this chart does not include thermal energy storage, which would cover a power range of a few kilowatts (kW) for thermal energy storage in buildings to more than 100 MW in CSP plants, with a discharge time of minutes to several hours.

When considering the technical performance or costs of energy storage, there are a number of caveats to consider. The first is the technical and commercial maturity of the storage technology. As of 2009, only four energy storage technologies (sodium-sulfur batteries, pumped hydro, CAES, and thermal storage)⁷² have a total worldwide installed capacity that exceeds 100 MW.⁷³ This doesn't mean that there isn't market potential for any individual technology or storage, in general; but it makes it difficult to assess the state of any individual technology given its limited deployment to date. This also leads to some uncertainty in two of the primary performance indicators for energy storage devices: efficiency and cost. Both of these values are often imprecisely reported, which makes it difficult to perform an accurate assessment of the potential for individual technologies or compare different technologies. Some major caveats when considering electricity storage include:

Efficiency

- 1) The standard measure of an electricity storage device's efficiency in the grid is the AC to AC round-trip efficiency, or $\text{AC kWh}_{\text{out}}/\text{kWh}_{\text{in}}$.⁷⁴ However, this is not always the value reported, especially for devices that store DC energy such as batteries and capacitors. In some cases, the DC-DC round-trip efficiency may be reported, and additional losses in power conversion efficiencies must be considered if the device is to provide applications in the grid.
- 2) Reported round-trip efficiencies may not include "parasitic" loads. These include heating and cooling of batteries and power-conditioning equipment. These parasitic loads can vary considerably depending on use, climate, and the length of each storage cycle.
- 3) The round-trip efficiency of several technologies cannot be directly compared. Thermal storage provides some, but not all of the services of a "pure" electricity storage device; while compressed-air energy storage is a hybrid device that requires both electricity and natural gas. These factors limit the value of a direct comparison, as discussed in more detail later in this section.

Cost

- 1) As stated before, only a few storage technologies have been deployed at large scale (greater than 100 MW). Estimated prices for emerging technologies may be for a semi-custom product (and consequently very high) or projected costs based on mass production (and perhaps overly optimistic). Even with more mature

⁷² This excludes small distributed applications including uninterruptible power supplies, off-grid homes, and the substation batteries. These applications are dominated by lead-acid batteries.

⁷³ 100 MW is equivalent to a small power plant and negligible in terms of overall grid-scale capacity. As of January 2008, the United States had 1,087,791 MW of installed capacity (EIA 2009a).

⁷⁴ The U.S. electric grid uses alternative current (AC) while batteries, capacitors, and several other electric storage technologies charge and discharge direct current (DC).

- technologies such as PHS and CAES, it has been some time since either has been built in the United States, so the cost of the next plant is somewhat uncertain.⁷⁵
- 2) As with any generation technology, large variations in prices occur from year to year due to commodity prices and the global economy. Therefore, cost estimates of storage technologies from different years may reflect market conditions as opposed to real differences.
 - 3) Storage technologies offer different classes of services and are comprised of an energy component and power component. The total cost of a storage device includes both components, with the limits of the target application. As a result, a direct comparison of a PHS device with a flywheel, for example, has limited value.

5.3.1 Storage Technologies for Power Quality Applications

Power quality applications require rapid response – often within less than a second – and include transient stability and frequency regulation. As with the other applications, the timescales of discharge may vary; but this class of services typically requires discharge times of up to about 10 minutes and nearly continuous cycling. Technologies for these applications include flywheels, capacitors, and superconducting magnetic energy storage (SMES).

Flywheels

Flywheels store energy in a rotating mass. Flywheels feature rapid response and high efficiency, making them well-suited for frequency regulation. Several flywheel installations have been planned or deployed to take advantage of high prices in frequency regulation markets (Lazarewicz 2009).

Capacitors

Capacitors⁷⁶ store electricity in an electric charge. Capacitors have among the fastest response time of any energy storage device, and are typically used in power quality applications such as providing transient voltage stability. However, their low energy capacity has restricted their use in longer time-duration applications. A major research goal is to increase their energy density and increase their usefulness in the grid (and potentially in vehicle applications.)

Superconducting Magnetic Energy Storage (SMES)

SMES stores energy in a magnetic field in a coil of superconducting material. SMES is similar to capacitors in its ability to respond extremely fast, but it is limited by the total energy capacity. This has also restricted SMES to “power” applications with extremely short discharge times. Several demonstration projects have been deployed.

⁷⁵ Furthermore, PHS and CAES depend on site-specific geologic conditions, which makes costs difficult to generalize.

⁷⁶ These devices have several names such as ultracapacitors and supercapacitors. “There is some uncertainty within the industry on the exact name for capacitors with massive storage capability. This is in part due to the many names of products by different manufacturers, but also due to the relative newness of the industry and recent advances.” (EPRI 2003).

5.3.2 Storage Technologies for Bridging Power

Bridging power applications include providing contingency reserves, load following, and additional reserves for issues such as forecast uncertainty and unit commitment errors. This set of applications generally requires rapid response (in seconds to minutes) and discharge times in the range of up to about an hour. Far less cycling is required than for power quality applications.

This application is generally associated with several battery technologies, which include lead-acid, nickel-cadmium, nickel-metal hydride, and (more recently) lithium-ion. Due to their rapid response, they can provide power quality services such as frequency regulation; but the continuous cycling requirement can limit battery life. Several demonstration projects have been built using these technologies to provide operating reserves.

5.3.3 Storage Technologies for Energy Management

Energy management applications include moving power over longer timescales, and generally require continuous discharge ratings of several hours or more. Technologies for these applications include several battery types, pumped hydro, compressed air, and thermal energy storage.

High-Energy Batteries

For many batteries, there is considerable overlap between energy management and the shorter-term applications discussed previously. Furthermore, batteries can generally provide rapid response, which means that batteries “designed” for energy management can potentially provide services over all the applications and timescales discussed.

Several battery technologies have been demonstrated or deployed for energy management applications. In addition to the chemistries discussed previously, the commercially available batteries targeted to energy management include two general types: high-temperature batteries and liquid electrolyte flow batteries

The most mature high-temperature battery as of 2009 is the sodium-sulfur battery, which has worldwide installations that exceed 270 MW (Rastler 2008). Alternative high-temperature chemistries have been proposed and are in various stages of development and commercialization. One example is the sodium-nickel chloride (ZEBRA) battery.

The second class of high-energy batteries is the liquid electrolyte “flow” battery. This battery uses a liquid electrolyte that flows across a membrane. The advantage of this technology is that the power component and energy component can be sized independently. As of 2009, there has been limited deployment of two types of flow batteries – vanadium redox and zinc-bromine. Other combinations such as polysulfide-bromine have been pursued, and new chemistries are under development.

In the United States, a primary application of energy management batteries has been T&D deferral; however, demonstration projects have been deployed for multiple applications (Nourai 2007, EPRI 2003).

Pumped Hydro Storage (PHS)

Pumped hydro is the only energy storage technology deployed on a gigawatt scale in the United States and worldwide. In the United States, about 20 GW is deployed at 39 sites, and installations range in capacity from less than 50 MW to 2,100 MW.⁷⁷ Many of the sites store 10 hours or more, making the technology useful for load leveling. PHS is also used for ancillary services. PHS uses conventional pumps and turbines and requires a significant amount of land and water for the upper and lower reservoirs. PHS plants can achieve round-trip efficiencies that exceed 75% and may have capacities that exceed 20 hours of discharge capacity. Environmental regulations may limit large-scale above-ground PHS development. However, given the high round-trip efficiencies, proven technology, and low cost compared to most alternatives, conventional PHS is still being pursued in a number of locations.⁷⁸ Alternative lower-impact configurations have been studied, including using a natural or mined underground formation for the lower reservoir, but this configuration has yet to be commercialized.

Compressed Air Energy Storage (CAES)

CAES technology is based on conventional gas turbine technology and uses the elastic potential energy of compressed air. Energy is stored by compressing air in an airtight underground storage cavern. To extract the stored energy, compressed air is drawn from the storage vessel, heated, and then expanded through a high-pressure turbine that captures some of the energy in the compressed air. The air is then mixed with fuel and combusted, with the exhaust expanded through a low-pressure gas turbine. The turbines are connected to an electrical generator.

CAES is considered a hybrid generation/storage system because it requires combustion in the gas turbine. The performance of a CAES plant is based on its energy ratio (energy in/energy out) and its fuel use (typically expressed as heat rate in BTU/kWh). CAES performance is estimated at an energy ratio of 0.6-0.8 and a heat rate of 4,000-4,300 BTU/kWh (Succar and Williams 2008). Because CAES uses both electricity and natural gas, a single-point definition of the round-trip efficiency of a CAES device does not represent an economic figure of merit.

The primary disadvantages of CAES are the need for an underground cavern and its reliance on fossil fuels. Alternative configurations for CAES have been proposed using manufactured above-ground vessels, new turbine designs to reduce fossil fuel use, or designs that re-use the heat of compression and avoid fuel use altogether.

Thermal Energy Storage

Thermal energy storage is sometimes ignored as an electricity storage technology because it typically is not used to store and then discharge electricity directly. However, in some applications, thermal storage can be functionally equivalent to electricity storage. One example is storing thermal energy from the sun that is later converted into electricity

⁷⁷ A complete list – including capacity, location, date of initial operation, and ownership – is available from EIA Form EIA-860, “Annual Electric Generator Report.”

⁷⁸ About 30 GW of new pumped hydro capacity has been proposed between 2006 and 2009. This represents more than double the existing capacity, and certainly implies there are considerable opportunities for new pumped hydro capacity (Adamson 2009).

in a conventional thermal generator. Another example is converting electricity into a form of thermal energy that later substitutes for electricity use such as electric cooling or heating.

The first example (storing thermal energy that is later converted into electricity) can be used with many types of thermal generators but is most often associated with concentrating solar power. In this application, thermal energy from the solar field is stored in molten salt or another medium. This energy can be recovered later and used to generate electricity, which turns this technology into a dispatchable source of energy.

Care must be used when discussing the efficiency of thermal energy storage. One of the major issues with electricity storage is efficiency losses. Electricity is a high “quality” source of energy, and transforming electricity into a stored medium and back incurs considerable losses. Thermal energy is a much lower quality of energy, but can be stored with much higher efficiency. In a CSP plant, thermal energy is stored before conversion to electricity. As a result, the round-trip efficiency of CSP thermal storage may be close to 100%, much higher than any electricity storage technology. However, CSP thermal storage can only store thermal energy produced from the solar field, as opposed to other storage technologies that can store electricity produced from any source.

Likewise, end-use energy storage can have extremely high round-trip efficiencies. Demand for electric-power cooling can be shifted by storing cold energy in the form of chilled water or ice during off-peak times and releasing that cold energy during times of peak demand. This effectively stores electricity with high round-trip efficiency.⁷⁹

End-use hot storage can also be used in both space heating and water heating applications. (Controllable water heating somewhat blurs the line between energy storage and demand response.) As with other forms of thermal storage, the effective round-trip efficiency of end-use hot storage is much higher than “pure” electricity storage devices but is limited by daily and seasonal heating demands.

5.4 Electric Vehicles and the Role of Vehicle to Grid

Electric vehicles (EVs – used here to represent both “pure” electric vehicles or plug-in hybrid electric vehicles) are a potential source of flexibility for VG applications. The charging of EVs can potentially be controlled, and provide a source of dispatchable demand and demand response. Controlled charging can be timed to periods of greatest VG output, while charging rates can be controlled to provide contingency reserves or frequency regulation reserves. Vehicle to grid (V2G) (where EVs can partially discharge stored energy to the grid) may provide additional value by acting as a distributed source of storage. EVs could potentially provide all three grid services discussed previously. Most proposals for both controlled charging and V2G focus on short-term response services such as frequency regulation and contingency. Their ability to provide energy

⁷⁹ Losses in the storage system are relatively small and occur through heat exchange from the stored cold energy and the surrounding environment. These losses can be partially offset by the potential increase in compressor efficiency when making ice or chilled water in the cooler evening compared to the daytime, which achieves net efficiencies close to 100%.

services is more limited by both the storage capacity of the battery, as well as the high cost of battery cycling. This could restrict their ability to provide time-shifting (energy arbitrage) beyond their ability to perform controlled charging.⁸⁰ The role of V2G is an active area of research, and because electrified vehicles in any form have yet to achieve significant market penetration, it is difficult to assess their potential as a source of grid flexibility. However, analysis has demonstrated potential system benefits of both controlled charging and V2G (Denholm and Short 2006). The role of EVs as an enabling technology requires additional analysis of their unique temporal characteristics of availability, unknown battery costs and lifetimes, and the availability of smart charging stations to maximize their usefulness while parked.

⁸⁰ This conclusion depends on the anticipated cycle life and cost of EV batteries. See Sioshansi and Denholm 2009 and Peterson et al. 2010 for a discussion of the impact of battery life and cycling on the value of V2G. However, controlled charging (without V2G) is still a potentially significant source of flexibility, with the ability to raise the minimum load and avoid curtailment.

6 Conclusions

The increasing role of variable renewable sources (such as wind and solar) in the grid has prompted concerns about grid reliability and raised the question of how much these resources can contribute before enabling technologies such as energy storage are *needed*. Fundamentally, this question is overly simplistic. In reality, the question is an economic issue: It involves the integration costs of variable generation and the amount of various storage or other enabling technologies that are economically viable in a future with high penetrations of VG. To date, integration studies of wind to about 20% on an energy basis have found that the grid can accommodate a substantial increase in VG without the need for energy storage, but it will require changes in operational practices, such as sharing of generation resources and loads over larger areas. Beyond this level, the impacts and costs are less clear, but 30% or more appears feasible with the introduction of “low-cost” flexibility options such as greater use of demand response. However, these studies have not necessarily focused on storage and generally do not attempt to determine the optimal system (including the amount of storage) that provides the lowest cost of energy.

There are technical and economic limits to how much of a system’s energy can be provided by VG without enabling technologies based on at least two factors: coincidence of VG supply and demand and the ability to reduce output from conventional generators. At extremely high penetration of VG, these factors may cause excessive (and costly) curtailment, which will require methods to increase the useful contribution of VG. However, the concern regarding how much VG can be used before storage is the most economic option for further integration currently has no simple answer, primarily because the availability and cost of grid flexibility options are not well understood and vary by region.

It is clear that high penetration of variable generation increases the need for all flexibility options including storage, and it also creates market opportunities for these technologies. Historically, storage has been difficult to sell into the market, not only due to high costs, but also because of the array of services it provides and the challenges it has in quantifying the value of these services – particularly the operational benefits such as ancillary services. The challenge of simulating energy storage in the grid, estimating its total value, and actually recovering those value streams continues to be a major barrier. VG complicates this issue because variability adds additional analysis challenges. The ability to simulate the cost impacts of VG and benefits of storage is still limited by the methods and data sets available. It is understood that VG increases the need for flexible generation and operating reserves, which can be met by energy storage. However, the value of energy storage is best captured when selling to the entire grid, instead of any single source. Evaluating the role of storage with VG sources requires continued analysis, improved data, and new techniques to evaluate the operation of a more dynamic and intelligent grid of the future.

Bibliography

The following are general overviews and reviews of energy storage technologies that provide additional information.

American Physical Society (APS). (2007). Challenges of Electricity Storage Technologies. Accessed December 2009 at <http://www.aps.org/policy/reports/popa-reports/upload/Energy-2007-Report-ElectricityStorageReport.pdf>

Chi-Jen, Y.; Williams, E. (2009). “Energy Storage for Low-Carbon Electricity.” Duke University Climate Change Policy Partnership.
http://www.nicholas.duke.edu/ccpp/ccpp_pdfs/energy.storage.pdf

Electric Power Research Institute/Department of Energy (EPRI/DOE). (2003). *Handbook of Energy Storage for Transmission and Distribution Applications*. Palo Alto, CA: 2003. 1001834.

Electricity Advisory Committee. (2008). *Bottling Electricity: Storage as a Strategic Tool for Managing Variability and Capacity Concerns in the Modern Grid*. Accessed December 2009 at http://www.oe.energy.gov/DocumentsandMedia/final-energy-storage_12-16-08.pdf

Electricity Storage Association. (2009). Accessed December 2009 at <http://www.electricitystorage.org/site/home/>

Hall, P.J.; Bain, E.J. (2008). “Energy-storage technologies and electricity generation.” *Energy Policy* 36(2008)4352–4355.

Ibrahima, H.; Ilincaa, A.; Perron, J. (2008). “Energy storage systems—characteristics and comparisons.” *Renewable and Sustainable Energy Reviews* 12 (2008) 1221–1250.

Pew Center on Global Climate Change. (2009). “Electric Energy Storage.” Accessed December 2009 at <http://www.pewclimate.org/technology/factsheet/EnergyStorage>

Rastler, D. (2008). “New Demand for Energy Storage,” September/October 2008. Accessed December 2009 at <http://www.eei.org/magazine/EEI%20Electric%20Perspectives%20Article%20Listing/2008-09-01-EnergyStorage.pdf>.

References

Ackermann, T.; Ancell, G.; Borup, L.D.; Eriksen, P.B.; Ernst, B.; Groome, F.; Lange, M.; Mohrlen, C.; Orths, A.G.; O'Sullivan, J.; de la Torre, M. (2009). "Where the wind blows." *IEEE Power and Energy Magazine*, Vol. 7, No. 6. (30 October 2009), pp. 65-75.

Adamson, D. M. (2009). "Realizing New Pumped-Storage Potential Through Effective Policies," *Hydro Review*, April 2009, pages 28-30.

American Society of Civil Engineers (ASCE). (1993). Task Committee on Pumped Storage of the Hydropower Committee of the Energy Division of the American Society of Civil Engineers. "Compendium of Pumped Storage Plants in the United States." American Society of Civil Engineers, New York.

American Wind Energy Association. (2009). "Annual Wind Industry Report Year Ending 2008." Accessed December 2009 at <http://www.awea.org/publications/reports/AWEA-Annual-Wind-Report-2009.pdf>

Boyd, D. W.; Buckley, O.E.; Clark, C.E. (1983). "Assessment of Market Potential of Compressed-Air Energy-Storage Systems." *Journal of Energy* 1983, 7, 549-556.

Butler, P.C.; Iannucci, J.; Eyer, J. (2003). *Innovative Business Cases For Energy Storage In a Restructured Electricity Marketplace*, SAND2003-0362 February 2003.

California Independent System Operator (CAISO). (2007). "Integration of Renewable Resources." November 2007. California Independent System Operator.

Corbus, D.; Milligan, M.; Ela, E.; Schuerger, M.; Zavadil, B. (2009). Eastern Wind Integration and Transmission Study -- Preliminary Findings: Preprint. 9 pp.; NREL Report No. CP-550-46505.

DeCesaro, J.; Porter, K.; M. Milligan. (2009). "Wind Energy and Power System Operations: A Review of Wind Integration Studies to Date." *The Electricity Journal*, Volume 22, Issue 10, Pages 34-43 (December 2009).

Denholm, P.; Sioshansi, R. (2009). "The Value of Compressed Air Energy Storage with Wind in Transmission-Constrained Electric Power Systems," *Energy Policy* 37, 3149-3158.

Denholm, P.; Margolis, R.M. (2008). "Supply Curves for Rooftop Solar PV-Generated Electricity for the United States," NREL/TP-670-44073.

Denholm, P.; Margolis, R.M. (2007a). "Evaluating the Limits of Solar Photovoltaics (PV) in Traditional Electric Power Systems" *Energy Policy* 35, 2852-2861.

Denholm, P.; Margolis, R.M. (2007b). "Evaluating the Limits of Solar Photovoltaics (PV) in Electric Power Systems Utilizing Energy Storage and Other Enabling Technologies." *Energy Policy* 35, 4424-4433.

Denholm, P.; Letendre, S.E. (2007). "Grid Services from Plug-in Hybrid Electric Vehicles: A Key to Economic Viability?" Electrical Energy Storage – Applications and Technology Conference. September 25, 2007.

Denholm, P.; Short, W. (2006). "An Evaluation of Utility System Impacts and Benefits of Optimally Dispatched Plug-In Hybrid Electric Vehicles." NREL/TP-620-40293.

Department of Energy (DOE). (1977). DOE Interagency Coordination Meeting on Energy Storage, 1977, CONF 7709116.

Desai, N.; Nelson, S.; Garza, S.; Pemberton, D.J.; Lewis, D.; Reid, W.; Lacasse, S.; Spencer, R.; Manning, L.M.; Wilson, R. (2003). "Study Of Electric Transmission In Conjunction With Energy Storage Technology," Lower Colorado River Authority, Texas State Energy Conservation Office, August 21, 2003.

Doherty, R.; Mullane, A.; Nolan, G.; Burke, D. J.; Bryson, A.; O'Malley, M. (forthcoming) "An Assessment of the Impact of Wind Generation on System Frequency Control." *IEEE Transactions on Power Systems*, forthcoming.

Energy Information Administration (EIA). (2009a). *Electric Power Annual*, 2009 (data for 2008). Accessed December 2009 at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

EIA. (2009b). "Repeal of the Powerplant and Industrial Fuel Use Act (1987)" Accessed December 2009 at http://www.eia.doe.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/repeal.html

Ela, E.; Kirby, B. (2008). "ERCOT Event on February 26, 2008: Lessons Learned." National Renewable Energy Laboratory. NREL/TP-500-43373, July 2008.

EnerNex Corporation. (2009). "Solar Integration Study for Public Service Company of Colorado." February 2009 for Xcel Energy. Accessed December 2009 at http://www.xcelenergy.com/SiteCollectionDocuments/docs/PSCo_SolarIntegration_020909.pdf

Electric Power Research Institute/Department of Energy (EPRI/DOE). (2004). *Energy Storage for Grid Connected Wind Generation Applications*, EPRI-DOE Handbook Supplement 1008703, December 2004.

EPRI. (2003). Handbook of Energy Storage for Transmission and Distribution Applications. Palo Alto, CA: 2003. 1001834.

EPRI. (1976). "Assessment of energy storage systems suitable for use by electric utilities." EPRI-EM-264, July 1976.

Electricity Storage Association (ESA). (2009). "Technology Comparisons." Accessed December 2009 at <http://www.electricitystorage.org/site/technologies/>

European Wind Energy Association (EWEA). (2009). "Global Installed Wind Power Capacity." Accessed December 2009 at http://www.ewea.org/fileadmin/ewea_documents/documents/press_releases/2009/GWEC_Press_Release_-_tables_and_statistics_2008.pdf

Eyer, J.M.; Iannucci, J.J.; Corey, G.P. (2004). "Energy Storage Benefits and Market Analysis Handbook." A Study for the DOE Energy Storage Systems Program. SAND2004-6177, December 2004.

Figueiredo, F.C.; Flynn, P.C.; Cabral, E.A. (2006). "The economics of energy storage in 14 deregulated power markets." *Energy Studies Review* 14, 131–152.

General Electric (GE) Energy. (2008). "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements." Prepared for the Electric Reliability Council of Texas (ERCOT), March 2008. Accessed December 2009 at http://www.uwig.org/AttchA-ERCOT_A-S_Study_Exec_Sum.pdf

Hurlbut, D. J. (2009). *Colorado's Prospects for Interstate Commerce in Renewable Power*. Prepared for the Colorado Governor's Energy Office, Renewable Energy Development Infrastructure (REDI). NREL Report No. TP-6A2-47179.

Independent System Operators and Regional Transmission Organizations Council (IRC). (2009). "2009 State of the Markets Report," prepared by the ISO/RTO Council. Accessed December 2009 at <http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/2009%20IRC%20State%20of%20Markets%20Report.pdf>

Jabbour, S.J.; Wells, W.M. (1992). "Optimal Dispatching of Storage Plants with Dynamics," in *Proceedings: Second International Conference on Compressed Air Energy Storage*. December 1992. EPRI TR-101770.

Kirby, B. (2004). "Frequency Regulation Basics and Trends," Oak Ridge National Laboratory, December 2004, ORNL/TM 2004/291.

Lamont, A. D. (2008). "Assessing the long-term system value of intermittent electric generation technologies." *Energy Economics* 30, No. 3 (May): 1208-1231.

Lazarewicz, M. (2009). "Commercial Flywheel Based Frequency Regulation Status," Electricity Storage Association annual meeting 2009. Washington, D.C., May 21-22, 2009.

- Lefton, S.A.; Besuner, P. (2006). "The Cost of Cycling Coal Fired Power Plants," *Coal Power Magazine*, Winter 2006.
- Lew, D.; Milligan, M.; Jordan, G.; Freeman, L.; Miller, N.; Clark, K.; and Piwko, R. (2009). "How do Wind and Solar Power Affect Grid Operations: The Western Wind and Solar Integration Study." NREL/CP-550-46517.
- Makarov, Y.V.; Ma, J.; Lu, S.; Nguyen, T.B. (2008). "Assessing the Value of Regulation Resources Based on Their Time Response Characteristics." June 2008, PNNL – 17632.
- Milligan, M.; Lew, D.; Corbus, D.; Piwko, R.; Miller, N.; Clark, K.; Jordan, G.; Freeman, L.; Zavadil, B.; Schuerger, M. (2009a). *Large-Scale Wind Integration Studies in the United States: Preliminary Results*. NREL/CP-550-46527, September 2009.
- Milligan, M.; Kirby, B.; Gramlich, R.; Goggin, M. (2009b). "The Impact of Electric Industry Structure on High Wind Penetration Potential." NREL/TP-550-46273, July 2009.
- Milligan, M.; Kirby, B. (2009). *Calculating Wind Integration Costs: Separating Wind Energy Value from Integration Cost Impacts*. NREL TP-550-46275.
- Nickell, B.M. (2008). "Wind Dispatchability and Storage Interconnected Grid Perspective." Presentation accessed December 2009 at <http://www.austinenenergy.com/About%20Us/Newsroom/Reports/taskForce/tfWindDispatchability.pdf>
- North American Electric Reliability Corporation (NERC). (2009). "Accommodating High Levels of Variable Generation," April 2009. Accessed December 2009 at http://www.nerc.com/docs/pc/ivgtf/IVGTF_Outline_Report_040708.pdf
- NERC. (2008). "NERC Glossary of Terms Used in Reliability Standards," February 12, 2008. Accessed December 2009 at www.nerc.com/files/Glossary_12Feb08.pdf
- Northwest Power and Conservation Council. (2009). "Draft Northwest Sixth Power Plan," September 2009. http://www.nwcouncil.org/energy/powerplan/6/DraftSixthPowerPlan_090309.pdf
- Nourai, A. (2007). "Installation of the First Distributed Energy Storage System (DESS) at American Electric Power (AEP)," June 2007, SAND2007-3580.
- Nourai, A.; Kogan, V.I.; Schafer, C.M. (2008). "Load Leveling Reduces T&D Line Losses," *IEEE Transactions on Power Delivery*, October 2008, Volume: 23, Issue: 4: 2168-2173.
- Palmintier, B.; Hansen, L.; Levine, J. (2008). "Spatial and Temporal Interactions of Solar and Wind Resources in the Next Generation Utility," Solar 2008, San Diego, CA.

- Peterson, S.B.; Whitacre, J.F.; Apt, J. (2010). "The Economics of Using PHEV Battery Packs for Grid Storage." *Journal of Power Sources*, 2010. 195: 2377-2384.
- PJM Interconnections (PJM). (2009a). "PJM Manual 12: Balancing Operations," Revision: 20, October 5, 2009. <http://www.pjm.com/markets-and-operations/ancillary-services/~media/documents/manuals/m12.ashx>
- PJM. (2009b). "PJM Manual 11: Scheduling Operations," Revision: 43. September 24, 2009. <http://www.pjm.com/markets-and-operations/ancillary-services/~media/documents/manuals/m11.ashx>
- Rastler, D. (2008). "New Demand for Energy Storage," *Electric Perspectives*, September/October 2008. Accessed December 2009 at <http://www.eei.org/magazine/EEI%20Electric%20Perspectives%20Article%20Listing/2008-09-01-EnergyStorage.pdf>
- Rebours Y.; Kirschen, D.S. (2005). "A survey of definitions and specifications of reserve services," University of Manchester, 2005.
- Sherwood, L. (2009). "U.S. Solar Market Trends 2008." Interstate Renewable Energy Council, published July 2009. Accessed December 2009 at http://www.irecusa.org/fileadmin/user_upload/NationalOutreachDocs/SolarTrendsReport/s/IREC_Solar_Market_Trends_Report_2008.pdf.
- Short, W.; Denholm, P. (2006) "A Preliminary Assessment of Plug-In Hybrid Electric Vehicles on Wind Energy Markets," NREL/TP-620-39729.
- Silverman, J. (ed). (1980). "Energy Storage: a vital element in mankind's quest for survival and progress." Transactions of the First International Assembly held at Dubrovnik, Yugoslavia, 27 May-1 June, 1979. Pergamon Press.
- Sioshansi, R.; Denholm, P.; Jenkin, T.; Weiss, J. (2009) "Estimating the Value of Electricity Storage in PJM: Arbitrage and Some Welfare Effects," *Energy Economics*. 31, 269-277.
- Smith, J.C.; Parsons, B. (2007). "What Does 20% Look Like?" *IEEE Power & Energy*, Nov/Dec 2007 22-33.
- Smith, J.C.; Milligan, M. R.; DeMeo, E.A.; Parsons, B. (2007). "Utility Wind Integration and Operating Impact State of the Art," *IEEE Transactions On Power Systems*, Vol. 22, No 3, August 2007.
- Strauss, P. L. (1991). "Pumped storage, the environment and mitigation." *Waterpower* 91, New York

Succar, S.; Williams, R.H. (2008). “Compressed Air Energy Storage: Theory, Resources, And Applications For Wind Power,” published for the Princeton Environmental Institute, April 2008.

Troy, N.; E. Denny, E.; M. O’Malley, M. (forthcoming) “Base-load Cycling on a System with Significant Wind Penetration” *IEEE Transactions on Power Systems*, forthcoming.

Walawalkar, R.; Apt, J.; Mancini, R. (2007). “Economics of electric energy storage for energy arbitrage and regulation in New York,” *Energy Policy* 35 (2007) 2558–2568.

Zavadil, R. (2006). “Wind Integration Study for Public Service Company of Colorado,” Enernex Corporation for Xcel Energy, May 2006.

REPORT DOCUMENTATION PAGE

Form Approved
OMB No. 0704-0188

The public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to Department of Defense, Executive Services and Communications Directorate (0704-0188). Respondents should be aware that notwithstanding any other provision of law, no person shall be subject to any penalty for failing to comply with a collection of information if it does not display a currently valid OMB control number.

PLEASE DO NOT RETURN YOUR FORM TO THE ABOVE ORGANIZATION.

1. REPORT DATE (DD-MM-YYYY) January 2010			2. REPORT TYPE Technical Report		3. DATES COVERED (From - To)	
4. TITLE AND SUBTITLE The Role of Energy Storage with Renewable Electricity Generation				5a. CONTRACT NUMBER DE-AC36-08-GO28308		
				5b. GRANT NUMBER		
				5c. PROGRAM ELEMENT NUMBER		
6. AUTHOR(S) P. Denholm, E. Ela, B. Kirby, and M. Milligan				5d. PROJECT NUMBER NREL/TP-6A2-47187		
				5e. TASK NUMBER WER8.5005		
				5f. WORK UNIT NUMBER		
7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES) National Renewable Energy Laboratory 1617 Cole Blvd. Golden, CO 80401-3393				8. PERFORMING ORGANIZATION REPORT NUMBER NREL/TP-6A2-47187		
9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)				10. SPONSOR/MONITOR'S ACRONYM(S) NREL		
				11. SPONSORING/MONITORING AGENCY REPORT NUMBER		
12. DISTRIBUTION AVAILABILITY STATEMENT National Technical Information Service U.S. Department of Commerce 5285 Port Royal Road Springfield, VA 22161						
13. SUPPLEMENTARY NOTES						
14. ABSTRACT (Maximum 200 Words) Renewable energy sources, such as wind and solar, have vast potential to reduce dependence on fossil fuels and greenhouse gas emissions in the electric sector. Climate change concerns, state initiatives including renewable portfolio standards, and consumer efforts are resulting in increased deployments of both technologies. Both solar photovoltaics (PV) and wind energy have variable and uncertain (sometimes referred to as "intermittent") output, which are unlike the dispatchable sources used for the majority of electricity generation in the United States. The variability of these sources has led to concerns regarding the reliability of an electric grid that derives a large fraction of its energy from these sources as well as the cost of reliably integrating large amounts of variable generation into the electric grid. In this report, we explore the role of energy storage in the electricity grid, focusing on the effects of large-scale deployment of variable renewable sources (primarily wind and solar energy).						
15. SUBJECT TERMS NREL; energy analysis; energy storage; electric grid; renewable energy; wind energy; solar energy; variability; solar photovoltaics; PV; variable generation; energy cost; renewable electricity generation; Paul Denhom; Erik Ela; Michael Milligan; Brendan Kirby						
16. SECURITY CLASSIFICATION OF:			17. LIMITATION OF ABSTRACT UL	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON	
a. REPORT Unclassified	b. ABSTRACT Unclassified	c. THIS PAGE Unclassified			19b. TELEPHONE NUMBER (Include area code)	

Standard Form 298 (Rev. 8/98)
Prescribed by ANSI Std. Z39.18