Chapter 12: Capacity and Flexibility Resources

SUMMARY OF KEY FINDINGS

Historically, Northwest power system planners have focused on providing sufficient energy to meet the annual energy load of the region. Largely because of the way the hydroelectric system developed, capacity, the ability to meet peak-hour load, and flexibility, the ability to rapidly increase or decrease generation output, were not significant problems.

Today, however, focusing regional power system planning solely on annual energy requirements is no longer adequate. Changes in the seasonal shape of Northwest load, increasing constraints on the operation of the hydrosystem to meet fish requirements, and rapidly increasing amounts of variable generation, especially wind, are making increased system capacity and flexibility a new priority.

Wind generation needs back-up, flexible resources to handle unexpected changes in its output. While the problems appear daunting, particularly in integrating new wind generation with a more constrained hydrosystem, there are solutions. The first step is to change system operating procedures and business practices to more fully utilize the inherent flexibility of the existing system. The Council believes these changes will be significantly cheaper to achieve, and can be implemented sooner than adding additional generating capacity solely to provide flexibility. It will also set the stage for determining how much flexibility will ultimately be needed from new generation.

Actions for these operating and business practice changes include: establishing metrics for measuring system flexibility; developing methods to quantify the flexibility of the region's existing resources; improving forecasting of the region's future demand for flexible capacity; improving wind forecasting and scheduling; transitioning from the current whole-hour scheduling framework to an intra-hour scheduling framework; and increasing the availability and use of dynamic scheduling. Fully implementing these improvements may also require physical upgrades to transmission, communication, and control facilities, though the cost of these upgrades is expected to be relatively small compared to the cost of adding new flexible capacity.

Because the reliable operation of the power system depends on agreement on these operating procedures, they cannot be changed overnight. However, significant studies and discussions are underway to achieve these changes and the Council urges they be supported by the region's utilities and power producers.

The next step is to ensure that resources added to meet peak-hour load are also flexible enough to respond to unexpected changes in wind plant output. These solutions should be sought in a sequence that makes economic sense. Actions include: considering rapid-response natural gas-fired generators, pumped-storage hydro plants and other storage resources, utility demand response programs and other potential smart grid applications, and geographic diversification of wind generation as options to meet the region's future demand for flexibility. Some balancing authorities, Bonneville especially, may need additional flexibility resources, either from better use of existing resources or from new resources, solely for integration of wind generation that meets load in other balancing authorities.

BACKGROUND

The fundamental objective of power system operations is to continuously match the supply of power from electric generators to the customers' load. Historically, for resource planners, the balancing problem was addressed in two ways. First, build enough generating capacity to meet peak-hour demand, plus a reasonable cushion to account for unexpected generator outages. Second, ensure an adequate fuel supply to operate electrical generators month-after-month and year-after-year to meet customers' energy demand. This was sufficient because traditional resources provided system operators with the means to deal with the fundamental requirements of power system operation. Because of the way the Northwest hydropower system was developed, over most of the past 40 years, the Northwest's resource planning has been more straightforward: to meet the annual energy needs of the system. The Northwest was able to focus on annual energy needs because the hydrosystem provided ample capacity and flexibility to balance generation and load at all times.

Today, power system operators and planners must again focus on ensuring that the installed generating capacity is flexible enough to rapidly increase or decrease output to maintain system balance second-to-second and minute-to-minute. This shift is a result of the dramatic increase in the region's use of wind generation, which creates unique challenges for system operators. Over the course of minutes and hours, the output of a wind generator can be extremely variable, ranging from zero to its maximum output. While power system operators try to predict changes in wind generation, they also need other capacity, sufficiently flexible, to offset unexpected changes in its output.

POWER SYSTEM REQUIREMENTS: CAPACITY, ENERGY, AND FLEXIBILITY

Capacity: Meeting Peak Demand

In previous plans, the Council focused primarily, like other regional resource planners, on the energy output of generators. Energy is the total output of a plant, typically measured over a year in megawatt hours or average megawatts. The touchstone for judging whether the region had adequate resources has long been whether the power system could generate sufficient energy during adverse water conditions. This focus was largely due to the Northwest's hydrosystem, which had an excess of installed capacity. Because most traditional generating resources, like natural gas, coal, and nuclear plants, provide additional capacity at the same time they provide the ability to generate energy, most resource planning was carried out in an environment in which capacity could be taken for granted, as long as enough additional energy capability was provided to meet the total energy needs of the region.

Capacity is the maximum net output of a generator, measured in megawatts. For most generation, this is relatively straightforward: the plants can operate at their maximum output level (within certain predictable environmental, emission, and technical constraints) if called upon by the system operators, unless they have an unplanned, or forced, outage. Utilities account for the probability of forced outages by carrying contingency reserves, which are required by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) reliability standards. The required contingency reserves equal about 6 percent to 8 percent of demand for most utilities.

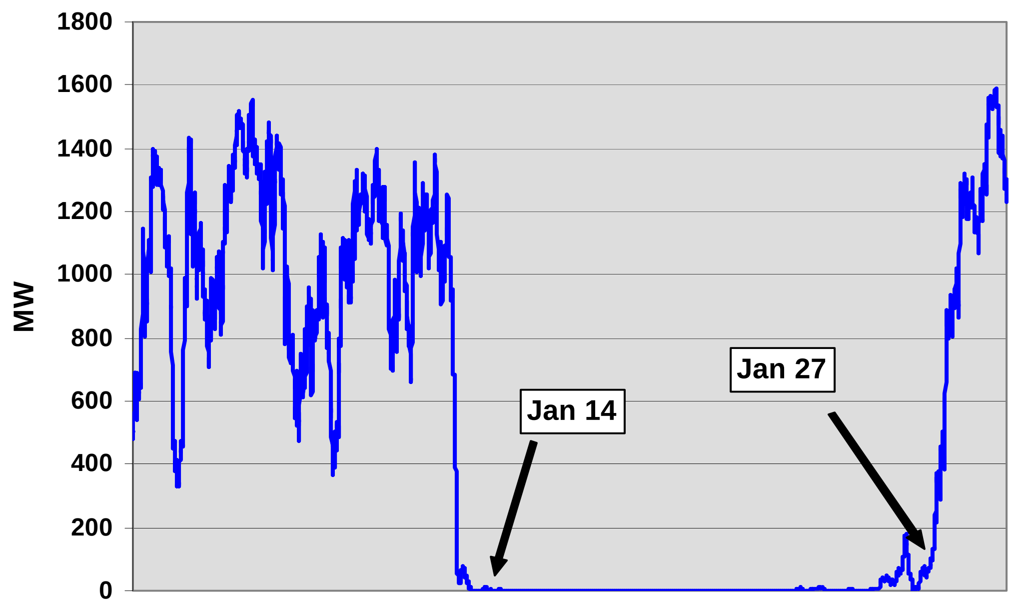
For hydroelectric generation, measuring capacity can be problematic. The total output of the hydrosystem is limited by its fuel supply, water, which is extremely variable from year-to-year. It is also limited by the fact that the reservoir system can only store about 30 percent of the annual runoff volume of water. Under some circumstances, there may not be enough stored water to run the generators at their maximum level to meet hourly load during peak conditions, like multi-day cold snaps in the winter or multi-day heat waves in the summer. While the machinery may be capable of reaching maximum output for short periods, it cannot sustain that level of output for longer periods. In fact, the maximum output a hydroelectric facility can provide depends on the duration of the output period--the longer the period, the lower the maximum sustainable output. This type of capacity is referred to as "sustainable capacity" and is a characteristic peculiar to hydroelectric systems.

The Northwest Resource Adequacy Forum, jointly chaired by the Council and Bonneville, with participation by other regional utilities and interest groups, has devoted considerable effort over the past several years to reaching an understanding of the hydrosystem's sustainable capacity value. The work of the forum is described more fully in Chapter 14.

Wind generation capacity also raises capacity issues because it is not controllable. Wind generation is variable; operators can reduce generation when the wind is blowing, but they cannot make it produce more, even if the rated wind capacity is much higher. Furthermore, the output level is relatively unpredictable and, in the Northwest, is unlikely to be available at times of extreme peak load--for example when load is high because of a winter cold spell or a summer hot spell.

The amount of installed capacity expected to be available during peak-load hours is often called a generator's "peak contribution" or "reliable capacity." There is a body of technical literature on methods for the calculation of this value. Analysis done by Bonneville and the Resource Adequacy Forum suggests that, for the wind area at the east end of the Columbia River Gorge, where much of the region's current wind generation is located, there is an inverse relationship between wind generation and extreme temperatures, both in winter and summer. This is likely due to widespread high pressure zones covering the region's load centers (the biggest ones being west of the Cascades) and the area of wind generation east of the Cascades during periods of extreme low and extreme high temperatures. Figure 12-1 illustrates the loss of wind generation during a recent winter period. While efforts to better define the reliable capacity of wind generators are ongoing, both in the Northwest and in NERC and WECC, the Resource Adequacy Forum has adopted a provisional peak contribution for wind of 5 percent of installed capacity. This work will need to address the impact of future wind development in other areas, such as Montana and Wyoming, that may have different weather patterns and could improve the overall capacity contribution of wind.

Figure 12-1: Bonneville Wind Generation January 5 - 29, 2009



The current adequacy assessment (Chapter 14) indicates that the Northwest will probably encounter a summer-capacity problem before a winter-capacity problem, largely because of hydrosystem constraints and different expectations about the availability of power from plants owned by the region's independent power producers and from wider Western markets. Providing capacity to meet peak demand is only one part of balancing generation and load. Resources added to provide energy and flexibility will also help the region meet its developing summer-capacity deficit.

Before system planners and operators began to emphasize flexibility as part of the solution to the balancing problem, it was possible to talk about pure peaking resources. Peaking units were resources added to the system primarily to meet peak-hour demand, without having to generate large amounts of energy over the course of the year. Peaking units have been characterized as low-fixed cost and high-operating cost resources. These cost characteristics correspond to their intended infrequent use as peaking plants. To a certain extent, this characterization originated with the historical practice of demoting aging, less-efficient baseload units to infrequent peaking duty. In recent decades, however, specialized units capable of delivering a broad array of ancillary services as well as peak capacity at reasonable efficiency--such as aeroderivative and intercooled gas turbines and gas-driven high-efficiency reciprocating engines--have appeared on the market. These units may have greater per-kilowatt capital costs than combined-cycle plants.

Resources in this category include simple-cycle gas turbine generators (both frame and aeroderivative), reciprocating engines, capacity augmentation features for combined-cycle gas turbines (including water or steam injection and fired heat-recovery steam generators), and utility demand response programs. Today, aeroderivative combustion turbines, reciprocating engines, and even some types of demand response, are often considered first for their flexibility and second for their ability to help meet peak demand. Demand response programs are described more fully in Chapter 5. These generating technologies are discussed later in this chapter and in Chapter 6.

Energy: Meeting Average Demand

Energy is the total output of a plant, typically over a year. For most plants, the maximum energy is simply the capacity times the number of hours per year that the plant runs, excluding forced or planned (maintenance) outages. For most types of generation, the energy output of the plant is not limited; the plant can run at its maximum level as long as desired, subject to forced or planned outages, and occasionally fuel supply and environmental constraints.

A fuller discussion of the regional portfolio results of the Council's analysis, as well as their implications for meeting capacity and energy requirements of the system, is in Chapter 10 of the plan.

Flexibility: Providing Within-hour Balance

The basic measures of a plant's flexibility are: its ramp rate, measured in megawatts-per-minute or some other short period; its minimum generation level; and its capacity. Minimum generation is most often defined by a combination of physical limits and economic limits, as when a plant's efficiency drops off dramatically below a certain point. Power system operators need to set aside a certain amount of flexible generation just to follow load, which varies. More flexibility is required if there is a significant amount of wind or other variable generation on the system.

The Northwest's hydroelectric generators are tremendously flexible resources. Physically, they have a wide operating range and very fast ramp rates. The inherent flexibility of the Northwest hydrosystem helps explain why flexibility has been taken for granted in previous Power Plans. This inherent flexibility is now partly limited by the challenges of salmon protection in Columbia and Snake rivers and the increasing amount of flexibility that is needed.

POWER SYSTEM OPERATIONS

The electric power system is organized into balancing authorities[1] for the purpose of operating the system reliably. Each generator (or fraction of a generator in specific circumstances) and load is in one, and only one, balancing authority. There are 17 balancing authorities in the Northwest Power Pool Area and 36 in the Western Interconnection.

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[1] Balancing authority is NERC terminology for the entity that is responsible for the actions. Balancing area is sometimes used for the portion of the electrical system for which the balancing authority is responsible.

Each balancing authority is responsible for a number of things, including continuously balancing load and resources, contributing to maintaining the frequency of the interconnection at its required level, monitoring and managing transmission power flow on the lines in its own area so they stay below system reliability limits, maintaining system voltages within required limits, and dealing with generation or transmission outages as they occur. It does these things using what are called ancillary services, most of which are services provided by generation or, less commonly, demand response under the control of the balancing authority. The potential to expand demand response for ancillary services is addressed further in Chapter 5.

Ancillary Services

The NERC and WECC reliability standards, and prudent utility practice, require balancing authorities to hold operating reserves, first to maintain load and resource balance in case of an outage of a generator or transmission line, second to meet instantaneous variations in load, and in the case of wind generation, fluctuations in resource output.

The portion of operating reserve held ready in case of an outage is called contingency reserve, specified by NERC and WECC standards. The portion of operating reserve meeting the second requirement is called regulating reserve in the reliability standards. Additional reserves that are not explicitly required by NERC and WECC, but are prudent practice and assist in meeting the regulation requirement, are often called balancing reserves.

Regulating and Balancing Reserves

Operators must balance load and resources and keep track of imports and exports, all while load is continuously changing.

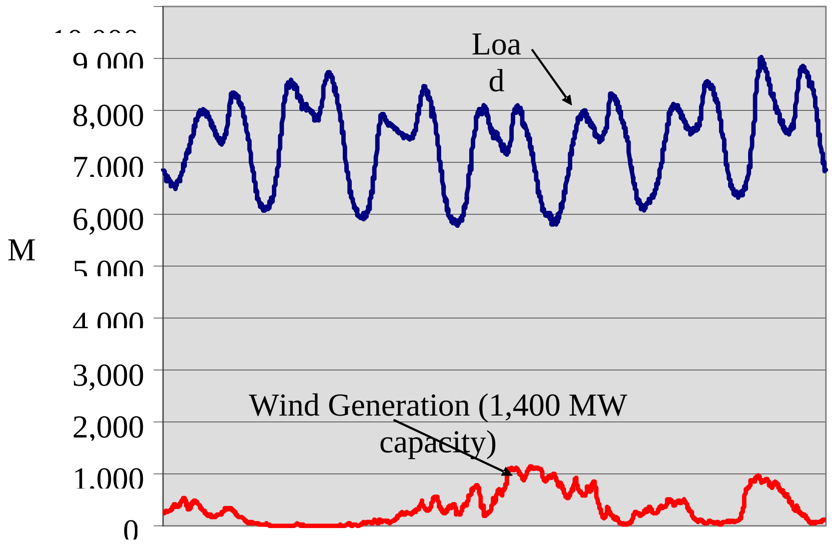
Balancing authorities do this by operating in a basic time frame of one hour, every hour of the day. The basic test of success in this balancing is called area control error (ACE). ACE is a measurement, calculated every four seconds, of the imbalance between load and generation within a balancing area, taking into account its previously planned imports and exports and the frequency of the interconnection. The NERC and WECC reliability standards govern the amount of allowable deviation of the balancing authority's ACE over various intervals, although the basic notion is that ACE should be approximately zero. The ACE is maintained through a combination of automatic and operator actions. The automatic part is done through a computer-controlled system called automatic generation control (AGC).

The basic regulation and balancing control challenge for the balancing authority is driven by load changes, both random, short-term fluctuations, and trends within the hour. It is exacerbated by the presence of large amounts of wind generation physically located in the balancing area, whether or not that wind is generating for the customers of the balancing area. There are specific exemptions from this requirement that in some cases require additional institutional or business practice changes, which are described later.

This is illustrated in several graphs based on five-minute interval data from the Bonneville balancing area in the first week of January 2008. The problems in this period are representative of the problems in other periods, although for Bonneville the problems are now magnified by the increase in installed wind capacity on its system. Bonneville now has approximately 2,800 megawatts of installed wind capacity. Figure 12-2 illustrates a typical weekly load pattern at five-minute intervals, with a sharp daily ramp in the morning as people rise, turn on electric heat, turn on lights, take showers, and as businesses begin the day.

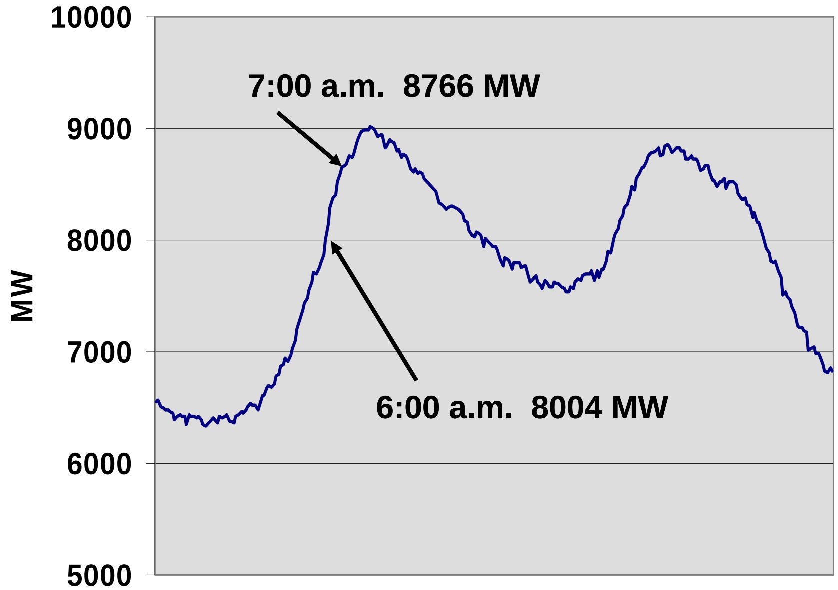
It also shows the Bonneville balancing area wind generation from the same period, illustrating the irregular pattern typical of wind generation. The data from this week will be used in several subsequent graphs, focusing on shorter time intervals and illustrating particular issues.

Figure 12-2: Example Load and Wind Pattern
BPA January 1-7, 2008, Midnight to Midnight



Focusing on a single day, January 7, 2008, Figure 12-3 highlights a single operating hour, from 6:00 a.m. to 7:00 a.m.

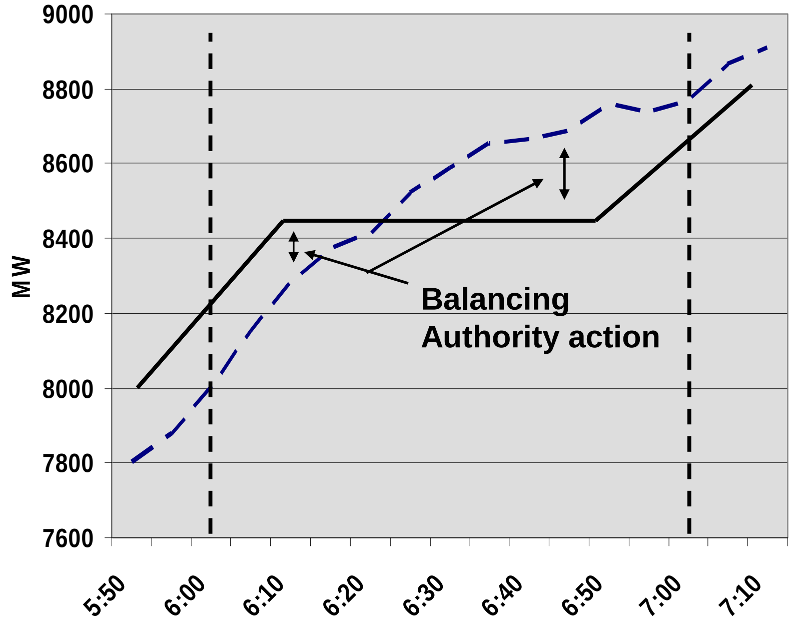
Figure 12-3: Daily Load Curve - BPA January 7, 2008
Midnight to Midnight



A balancing authority has to deal with a load ramp of, for example, 762 megawatts over the course of an hour, using the generation under its control in its own balancing area. At the same time, it must deal with any imports or exports that have their own time pattern for adjustment. Scheduling between balancing authorities in WECC is generally done in one-hour increments, with the schedules ramping in across the hour, from 10 minutes before the hour to 10 minutes after the hour.

Figure 12-4 focuses on the 6:00 a.m. to 7:00 a.m. load from the previous graph, while adding a hypothetical net schedule (including exports from and imports into the balancing area), and the generation scheduled to meet the average hourly load by any of its providers, including the transmission provider's merchant arm. The balancing authority must address the differences (both positive and negative) between the total scheduled generation and the net load in the balancing area by operating the generation in its control either up or down to match the load instantaneously, and to manage its ACE to acceptable levels. The graph points to the differences between scheduled generation and actual load that requires balancing authority action.

Figure 12-4: Example Hourly Scheduling



There are NERC and WECC reliability standards that govern how that action must be taken. In addition to contingency reserves, which must be available in case of a sudden forced outage, the standards require regulation reserves, which is generation connected to the balancing authority's AGC system. The standards do not require any specific megawatt or percentage level of regulation reserves. Rather, they require that the balancing authority hold a sufficient amount so that its ACE can be controlled within the required limits. How the balancing authority meets the requirements highlighted in Figure 12-4 involves some discretion on its part.

Most balancing authorities prefer to break the requirement into two parts: one meeting the pure regulation requirement, allowing AGC generation to respond every four seconds; the other adjusting generation output over a longer period, typically 10 minutes. The pure regulation requirement is illustrated by Figure 12-5, which shows a hypothetical, random pattern at four-second intervals (which is the kind of pattern the load actually exhibits) on top of a five-minute trend. This is the load that the generation on AGC actually follows.

Figure 12-5: Example Load at Four-Second Intervals Over Five Minutes

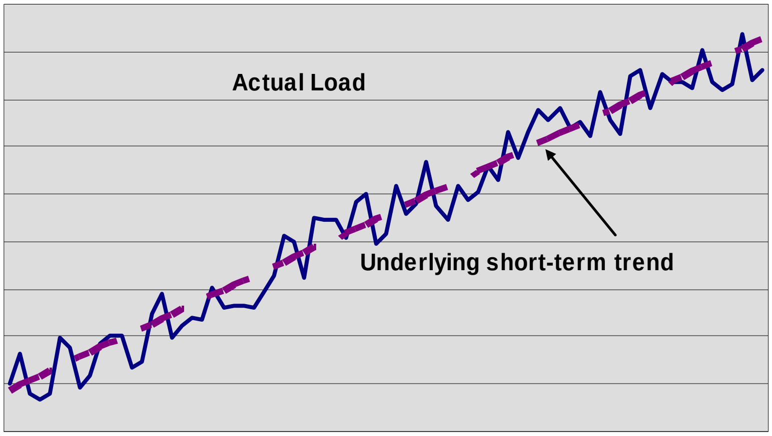
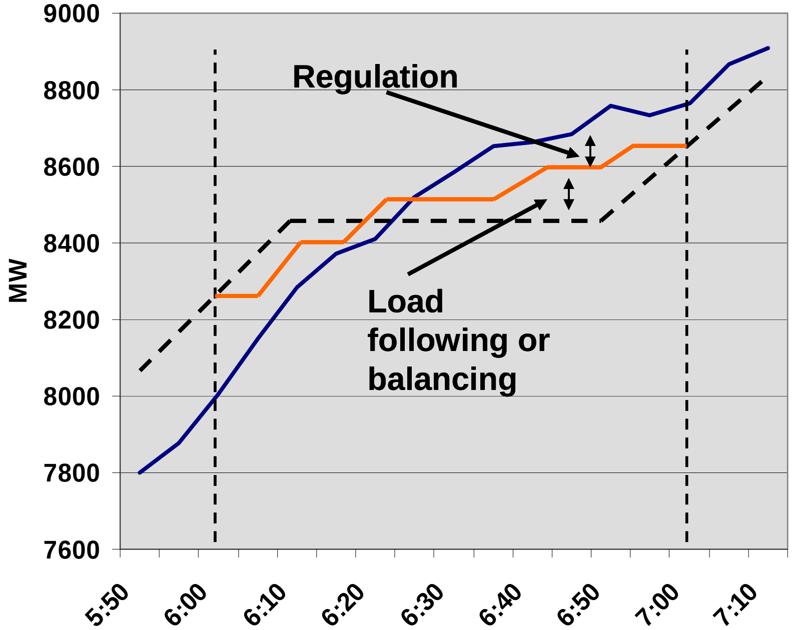


Figure 12-6 illustrates one pattern of breaking that requirement up, separating the regulation requirement for generation on AGC from the remaining requirement, usually called load-following or balancing.[2]

Figure 12-6: Illustration of Hourly Scheduling with Load Following



Balancing authorities plan for regulation and balancing services before the need for them arises. They ensure that enough scheduled generation is on AGC to provide moment-to-moment regulation services. They also plan to operate some generators at levels lower than they otherwise would in order to have the ability to increase generation and provide incremental load-following. Conversely, they may also need to operate some generators at levels higher than they

[2] When the only remaining requirement is the variation in load, load-following is the most common term. When the requirement includes the effect of variable generation, like wind, the term balancing is often used instead.

otherwise would in order to have the ability to decrease generation and provide decremental load following.

By operating generators in this manner, a balancing authority can incur increased operation costs, increased maintenance costs, and foregone revenues. These are the opportunity costs of providing regulation and load-following or balancing services. Balancing authorities typically decide which generators to use for regulation and load-following based on the physical characteristics of their generators and the opportunity cost of operating specific generators in this manner. Much of the region's flexibility, and particularly for the large amount of wind generation in Bonneville's balancing area, has been provided by the hydrosystem. This description focuses on issues raised for the Northwest and its hydro system, but it needs to be recognized that there are other areas of the world or the U.S., like Texas, where integrating significant amounts of wind has taken place using non-hydro resources. Texas, for instance, currently integrates approximately 8,000 megawatts of wind primarily with combined-cycle gas generation.

Historically, the cost of operating the power system to provide regulation and load-following services received little attention. The effect of wind and other variable generation on the balancing authority's ability to balance generation and load has raised awareness of the cost of providing these services. Improving operating procedures and business practices should help to hold down integration costs, but they will likely increase over time as more variable generation is added to the system.

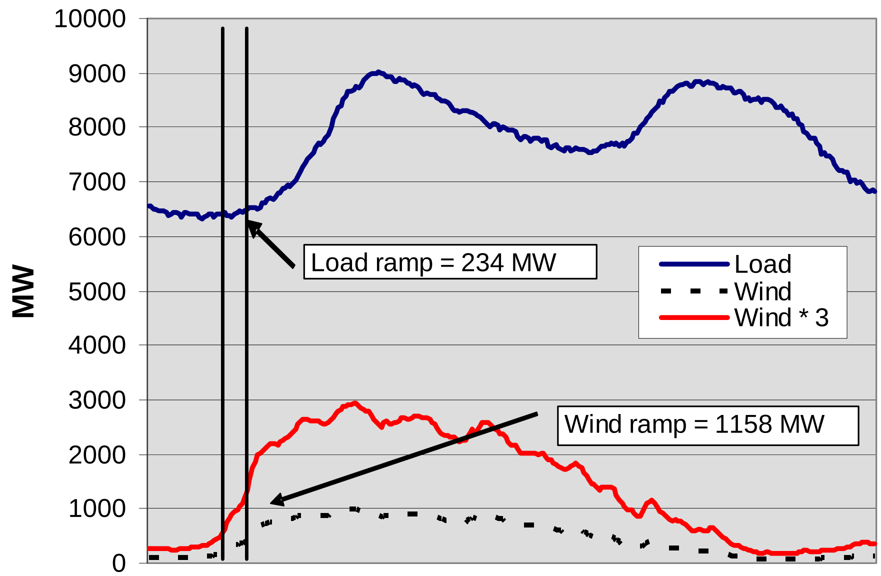
FLEXIBILITY ISSUES RAISED BY WIND GENERATION

Unpredictable and rapid swings in the output of wind generators have increased the need for power system flexibility. Load is typically much more predictable in the one-to-two hour time frame than wind generation. If load is relatively flat, and the wind unexpectedly drops off over the course of 10-20 minutes, then system operators must ramp up other generation at the same speed that the wind generation is ramping down in order to maintain load and resource balance and support the system frequency. Likewise, if the wind unexpectedly increases, then system operators must be able to ramp down other generators in order to maintain load and resource balance.

The possibilities become more complicated with changes in both wind generation and load over a given time period. But the result is still the need to be able to quickly adjust generation up or down.

Figure 12-7 illustrates a situation where both load and wind generation increased at the same time. It shows the load and wind pattern from the last day of Figure 12-1, and the effect of wind generation if its capacity were three times greater than what was operating on January 7, 2008, assuming for the sake of illustration that the additional wind generation did not bring any geographical diversity with it. Note that Bonneville already has about 2,800 megawatts of installed wind capacity, instead of the then 1,400 megawatts. Bonneville is concerned about the potential of over 6,000 megawatts by 2013.

Figure 12-7: January 7, 2008 Load and Hypothetical Wind Data Midnight to Midnight



Looking at the early morning hours only, between 3:00 a.m. and 4:00 a.m. indicated by the vertical bars on the graph, we see an increase in load of 234 megawatts in that period. We also see an increase in the hypothetical wind generation of 1,158 megawatts. System operators would need to ramp down other generators by 924 megawatts to maintain system balance. Because Bonneville can face significant minimum generation requirements in the low-load night time hours, this pattern is a particular problem for them. Solutions to these issues, some of them under development already, are discussed in the following section.

For capacity and energy, it is possible to provide estimates of the timing and size of future deficits. At this time, we are unable to make a similar projection for flexibility. This is because the industry has not yet developed standard methodologies and metrics to make such an assessment. However, Bonneville has estimated in its recently concluded 2010 rate case that by the end of 2011 it might need to set aside up to about 750 megawatts of generation to respond to unexpected drops in wind generation, and about 975 megawatts of generation to respond to unexpected increases in wind generation. These amounts are based on a wind forecast of almost 3,845 megawatts of installed wind, a 30-minute persistence forecast and several mitigation measures for wind generation outside the level of the set-aside balancing reserves. For Bonneville's needs specifically, see also the discussion in Chapter 13.

Response to Growing Need for Flexibility

The response needs to be twofold. First, modify existing operating procedures and business practices to allow the maximum and most efficient use of the region's existing flexibility for those balancing authorities with large amounts of wind generation. Second, the new dispatchable generation needed for energy, or to meet the peak-hour capacity needs of the system (should that become the primary need in the future), should also be able to be adjusted up or down to deal with changes in wind output, and to allow the region's balancing authorities to maintain their ACE measures within acceptable bounds.

Institutional Changes

There are several changes in operating procedures and business practices that would either reduce the burden on the balancing areas or substantially increase the available flexibility of the existing system.

Increasing the accuracy of short-term wind forecasting, either by wind generators or the balancing authorities themselves would reduce the amount of balancing reserve capacity needed to cover a forecast error. Bonneville has estimated, for example, that using the prior 30 minutes' generation level (rather than previous methods that looked further back) as the forecast for the next hour would substantially reduce the forecast error and the amount of needed balancing reserves. Bonneville has made this adjustment and adopted other methods to increase forecast accuracy. More sophisticated wind modeling is also being explored.

Going to a 10-minute scheduling window instead of the current whole-hour scheduling would also help maintain the host balancing authority's ACE by allowing it to bring in generation from other balancing authorities. This would require a more developed market (either bilateral or centralized) in these intra-hour, short-term generation deliveries to take advantage of the new framework. The joint initiative between ColumbiaGrid, Northern Tier Transmission Group, and WestConnect is taking steps in this direction by creating a tool to facilitate within-hour transactions on a bilateral basis.

Increasing the availability and ease of use of dynamic scheduling is another important change. This mechanism enables generation in one balancing authority to be transferred into another balancing authority for the ACE calculations of the two areas. This is helpful for several reasons. It allows available generation in one balancing authority to be used in another to meet the latter's regulation and balancing needs.

It also allows wind generation that is physically located in one balancing authority, but meeting load in another balancing authority, to be effectively transferred out of its area and into the second authority's area and ACE. Normally, while the FERC Open Access Transmission Tariff (OATT) allows the first balancing authority to charge some other party (the wind generators meeting external load or the external load) for the ancillary services, including regulation and balancing, NERC standards require that the host balancing authority provide the physical response. Dynamic scheduling allows both the physical response and cost of the wind generation to be the responsibility of the recipient load.

Dynamic scheduling is a long-established practice, but is typically done now on a case-by-case basis for relatively long periods, and it requires time-consuming, individual coordination between balancing authorities. Work is underway by the joint initiative to standardize the protocols and communication to make dynamic scheduling easily and quickly available--ideally so that dynamic schedules could be changed on an hour-to-hour or shorter basis.

There are some additional issues that need to be resolved regarding the limits on the amount of generation that can be dynamically scheduled over various transmission paths, particularly if the schedule involves long distances; for example, dynamic scheduling between Bonneville and the

California ISO. Among these issues is control of voltage levels in the system. Voltage levels on transmission lines are in part a function of the line loading, and dynamic scheduling tends to change line loadings rapidly, increasing the burden of controlling voltage levels within reliability limits. The Northern Tier Transmission Group and ColumbiaGrid have formed a group called the Wind Integration Study Team to examine these limits within the two entities.

Adding Flexible Capacity

System planners and operators are looking at resources that can be used to meet peak-hour demand and respond to variations in wind output. These flexible-duty resources do not necessarily need to generate large amounts of energy over the course of the year. Resources typically placed in this category include: rapid-response natural gas-fired generators; storage resources such as pumped-storage hydro plants; and utility demand response programs.

In the near term, natural gas-fired turbines and reciprocating engines appear to be good options for meeting the increased demand for flexibility. To offset unexpected changes in wind output, these resources need rapid-start capability and efficient operation at output levels less than full capacity.

The LM6000 Sprint (50-megawatt) and LMS100 (100-megawatt) aeroderivative turbines are two good candidates for flexibility augmentation. Starting cold, both turbines can be ramped to their maximum output within 10 minutes. These aeroderivative turbines are more efficient than comparable frame turbines, and therefore more cost-effective to operate at partial output levels. The LM6000 Sprint is a commercially mature technology with more than 200 units in operation. The first LMS100 unit went into commercial operation at the Groton Generating Station in South Dakota in 2006.

Gas-fired reciprocating engines are also a good flexibility option. The Plains End Generating Facility in Colorado is a 20-unit plant that has an output range of anywhere from 3 megawatts to 113 megawatts. The engines have a 10-minute quick start capability and can ramp up and down in response to an AGC signal. All of the above options can be constructed with short lead times, and therefore are good near-term flexibility options. A more complete description of these natural gas-fired generating technologies is provided in Chapter 6.

Pumped-storage hydro is a good mid-term option for meeting increased demand for flexibility since it can quickly change its operating level. These hydro plants operate in either a pumping mode or a generating mode. Traditional operation of pumped-storage hydro is based on the price of electric power. When the price of electric power is low, water is pumped from a source to a storage reservoir located at a higher elevation. When the price of electric power is high, the stored water is released and passed through a turbine to generate power.

As more wind power is added to the system, pumped-storage operation is likely to respond to the price of regulation and load-following services. For example, operators of pumped-storage plants can commit in advance to increase pumping when there are unexpected increases in wind output. Plants with variable-speed pumps are likely to be more responsive in these circumstances. Likewise, operators can also commit to increase generation when wind power output unexpectedly drops. Furthermore, operating the plant in this manner is not likely to result in dramatic operating cost increases or reduced revenue. However, with a 13-year construction lead time, and high capital cost, risk is high. Other options may capture a large share of the ancillary services market before a new pumped-storage plant can be brought on-line.

The potential use of hot water heaters, plug-in hybrid vehicles, and other demand response options to provide regulation and load-following services is described in Chapter 5, Appendix H, and Appendix K.