B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

White Paper

Challenge for the Northwest

Protecting and managing an increasingly congested transmission system

April 2006

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In August of 2005, the Pacific Northwest grid exceeded industry limits for reliable operating conditions for more than five minutes on 29 occasions. While none of these events lasted long enough to be a sanctionable violation, 16 events did require emergency action to curtail schedules or to redispatch generation.

It was high summer, and air conditioners in both the Pacific Northwest and California were cranked up. At the time, utilities and power marketers in Canada and the U.S. Northwest, including the Bonneville Power Administration, were moving large amounts of surplus power into California. A substantial portion of this service was using nonfirm transmission[1] that had been reserved no more than a day ahead and some only an hour ahead. As a result, power flows across some transmission paths became overloaded,[2] a condition known as congestion.

Fortunately, in all cases, BPA operators and dispatchers were able to restore the transmission system to reliable operating conditions in less than 30 minutes by taking aggressive actions to redispatch federal generation and, in some cases, curtail transmission schedules to move power flows to other flowgates. Some of these actions forced the power market to make rapid arrangements to maintain service to loads. Dispatchers were both skilled and lucky. The luck came into play because no unpredictable contingencies, such as a critical generator outage or the loss of a major transmission line, occurred during this time to destabilize the system. Such instability could have left the system vulnerable to a cascading electrical failure.

What are flowgates?

The term "flowgates" is used throughout this paper. Flowgates are a collection of geographically close transmission lines through which electricity must flow to reach its intended destination. Each flowgate has a capacity limit set under industry reliability standards. The total capacity limit for the flowgate is often less than the sum of the capacity limits of the individual lines because of interactions between systems. The terms "flowgates" and "cut-planes" are generally synonymous.

What is the issue?

Today, the Northwest transmission grid is being used in ways that weren't envisioned when it was built. It is operating in a new environment, where markets, generation resources and transmission patterns have changed dramatically. There is no doubt that the Pacific Northwest grid is a magnificent system, but – like transmission systems elsewhere in the nation – the Northwest system is showing considerable stress as increasing demands test the system's resiliency.

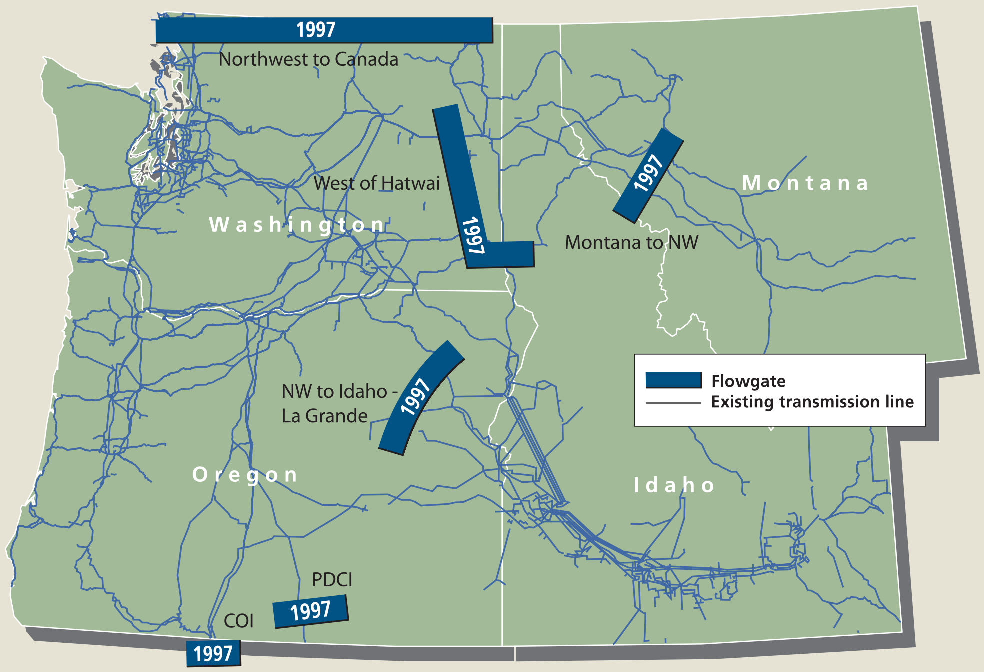
Historically, BPA could accept all schedules for access to its transmission because excess capacity was available, but today this practice

1 As an example, on Aug. 26, 2005, about 1,500 megawatts of energy had been dispatched to flow on the Northern Intertie that had not been anticipated in Available Transfer Capability planning studies, while about 1,250 megawatts of energy was dispatched on the Southern Intertie that also had not been anticipated.

2 In the context of this paper, the term "overloaded" means that flows across transmission flowgates exceeded industry standards for reliable operating conditions.

Growing congestion

Flowgates – points where the grid gets congested – have proliferated in the last few years as more and more transmission paths are reaching their limits. (Flowgates are marked with the year BPA posted flowgate limits.)



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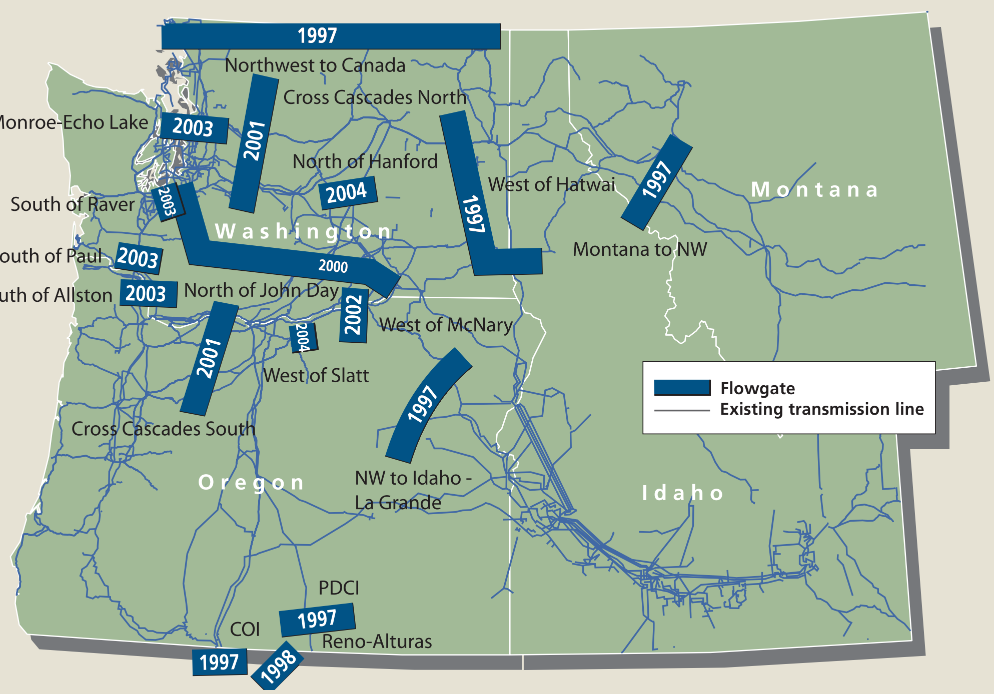

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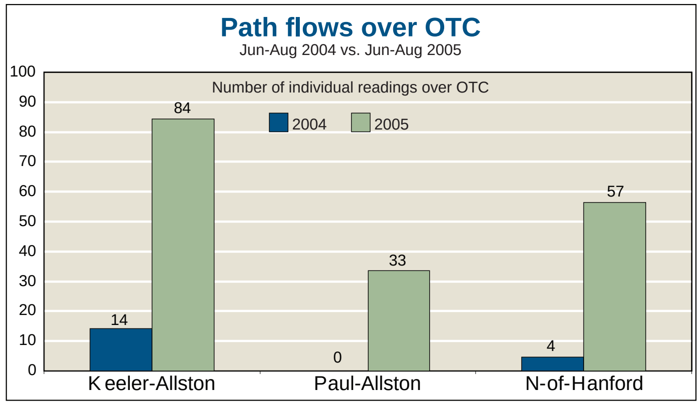
puts the system at risk because the excess capacity is no longer available at all times. Despite this, BPA continues to accept all schedules, because it does not have the tools or processes in place to determine ahead of time the relative contribution firm and nonfirm schedules make to actual powerflows.

A major consequence is the growing number of times when the system is congested and operating outside of its operating transfer capability (OTC), the industry threshold for safe reliable conditions. During such times, dispatchers must take corrective action in real time to bring the system back within operational standards. Such instances expose the system to catastrophic consequences should a contingency, such as a major line outage, occur. And the more often the system is operating outside limits, the greater the exposure.

This is not to say that BPA does not build in headroom to deal with the unexpected. BPA continues to operate its transmission system conservatively to maintain high reliability. When OTC levels are set on a transmission path, these levels assume extreme conditions such as high temperatures and high loads. In addition, OTC ratings include operating margins according to standards set by the North American Reliability Council (NERC) and the Western Electricity Coordinating Council (WECC).

Nevertheless, problems presented by congestion have been growing steadily and have become increasingly urgent as dispatchers find themselves operating more and more in an "emergency" mode. Lacking the tools and processes to predict congestion ahead of time, and thus prevent or minimize it, they are forced to react in real time. And that significantly reduces their ability to deal with any contingency that could occur. As the 1996 outages that began in the Northwest and the 2003 East Coast blackout forcibly demonstrated, multiple events on a system can occur at lightning



speed, leaving dispatchers with little or no time to react.

There were at least 174 occasions from June through August 2005 when flows exceeded flowgate OTC on the Northwest grid. (See graph above.) Although none lasted long enough to constitute a sanctionable violation, detailed analysis did reveal occasions that were alarming because of their duration. On 20 of these occasions last August, dispatchers had to take actions (including bypassing series capacitors and requesting phase shifter operation[3]) to reduce powerflows over the affected flowgates. And, for 16 of the 20 occasions, dispatchers had to curtail schedules or redispatch federal generation. Such actions can lead to less efficient power markets and higher costs to consumers. There was a marked increase in these incidents from the previous year, and the incidents were well above historical levels. (See Appendix A for details on OTC exceedences.)

The result is that today network congestion is not "managed" so that it can be avoided; it is simply reacted to when it happens, often with blunt and disruptive tools. The problem manifests itself in three ways:

- ✦ Reliability put at risk
- ✦ Lack of compliance with tariffs and reliability standards
- ✦ Reduced economic efficiency

3 See "Bypassing series capacitors and phase shifters" on page 14 for more detailed information.

Because over half of the high voltage transmission in the Pacific Northwest grid, including a large portion of major interregional interties,[4] is owned and operated by BPA, transmission congestion on the BPA system affects the entire Western Interconnected System. Also, loads and generation located in the region but not connected directly to BPA's transmission system affect the BPA system. At present, the Northwest grid is managed by 17 individual control area operators serving more than 20 generating and transmitting utilities.

A congestion management solution is needed, whether it is implemented solely on BPA's facilities or as part of a regional solution. An independent one-utility approach could lead to effective solutions. While BPA is participating in the creation of ColumbiaGrid and remains commited to participation in an entity that can implement effective longer-term solutions, congestion management action is needed now.

This paper will explore what is causing the current congestion problem and options for dealing with it. BPA hopes the issues raised here will stimulate regional discussion. The paper is a starting point to re-engage customers and other stakeholders and to invite input about potential approaches to solutions. BPA also seeks comment to determine if it is asking the right questions and selecting the appropriate principles and criteria for making eventual decisions. BPA's ultimate goal is to continue to fulfill its mission to provide a transmission system for the Pacific Northwest that is reliable, adequate, economical and secure. A solution must capture all these qualities. To this end, BPA is proposing three principles to guide development of solutions. (See the box on this page.)

4 An intertie is a large transmission line or lines that interconnect more than one region, allowing power to flow between regions; for example, to and from the Northwest and other geographic regions such as Canada and the Southwest.

Principles for addressing congestion solutions

A solution must provide for:

1. Keeping the system safe. This means operating the system reliably at the least cost to consumers. This principle is the overarching priority.
2. Maintaining consistency with tariffs and with North American Electric Reliability Council and Western Electricity Coordinating Council requirements and operating criteria.*
3. Ensuring a commercially adequate transmission system at least cost to consumers.

* In circumstances where it appears such consistency significantly compromises reliability or least cost, BPA would consider seeking modifications, while honoring the existing tariff and criteria until they are modified.

What is congestion?

Congestion usually occurs when demand for access to the transmission network is high and the demand is in patterns that the transmission system was not designed for. Demand on portions of the Pacific Northwest grid is particularly high in summer when large amounts of power are moving into California. This can trigger a flow of electricity in a pattern that results in powerflows over certain flowgates that may exceed limits for operating the transmission system reliably. The industry standard for reliability, the operating transfer capability (OTC), represents the maximum use, based on complex system studies, that the system can handle and still maintain reliability in the face of worst-case scenarios.

The Western Electricity Coordinating Council (WECC) assesses penalties on transmission owners or flowgate operators when a transmission flowgate OTC is exceeded longer than 20 or 30 minutes (the timing depends on whether a stability-limited path or a thermally

A layman's view of congestion

While a transmission grid is a hugely complex and highly interconnected network of lines and substations for delivering electricity from generators to loads, it helps to think of it in layman's terms. It is like a huge network of interstate highways connecting major points, only instead of cars moving along this network, it's electrons. As with a highway system, some routes bear such heavy traffic at times that they become congested. And, like a highway system, the congestion isn't necessarily uniform over the day or even days. It can come in peaks and valleys; it can be unpredictable, and it may occur only a few hours a year. For this reason, a system that sees no congestion would likely be overbuilt and uneconomical.

Weather, unusual traffic patterns, accidents, construction and detours all can exacerbate congestion in a highway system, and the same is true for a transmission system. It can be affected by generation and load patterns, weather, accidents and system outages.

limited path is involved).[5] When the OTC is exceeded, the system may become unstable. If, under these conditions, the wrong combination of contingencies were to occur, the transmission system would be more likely to experience a catastrophic cascading – uncontrolled – outage such as the ones that triggered in the Northwest in July and August 1996 or, more recently, the East Coast/Midwest blackout in August 2003. (See box on "The Blackouts of 1996 and 2003" on page 6.)

Contingencies can occur for a variety of reasons ranging from unpredictable generation outages to loss of transmission lines due to such things as lightning strikes or shot-out insulators. Because the system is built to be resilient so it can handle unpredictable events, problems usually only occur when there is more than one contingency at a time on the system.

While there are not a great number of OTC exceedences that compromise the system and they may only account for a few hours a year, the few that exist are dangerous because they leave the system vulnerable to the next contingency, which could increase the risk of an uncontrollable cascading outage. If congestion is not yet chronic, it is persistent. And, most significantly, it is growing as demand on the Pacific Northwest grid grows.

How has the system changed?

BPA's transmission system was originally built to deliver the Columbia Basin's abundant and low-cost federal hydropower to existing and potential regional markets. It has served as a foundation upon which other transmission and distribution systems were built. Excess transmission capacity has been made available for many years to nonfederal utilities, allowing them to move power from remote resources to regional loads. Over the years, BPA also expanded its system to meet regional needs and to support the sale of surplus power out of the region. Interties to the Southwest in particular created a huge benefit for consumers by allowing the market to take advantage of the West's seasonal diversity.[6]

Continuing into the early 1980s, the grid was expanded to integrate new hydroelectric and thermal resources including coal and nuclear power. The 500-kilovolt transmission lines BPA developed during this time became the backbone of the Northwest grid.

5 See glossary for definitions of stability-limited path and thermally limited path.

6 Pacific Northwest hydropower is most plentiful in spring, and the region's power loads peak in winter. California and Southwest loads peak in summer. This seasonal diversity allows for power swaps between regions that reduce the need for both regions to build expensive resources. However, the amount of diversity between the two regions has been decreasing as summer loads increase in the Northwest as more people use air conditioners. As a result, some flowgates may experience higher loads in summer.

The blackouts of 1996 and 2003

Two major outages struck the power grid of the western United States in the summer of 1996. On July 2, a line owned by PacifiCorp (Jim Bridger-Kinport 345-kV) contacted a tree in Idaho. Normally, that would not cause a widespread outage, but coupled with near-record hydro generation in the Northwest, high north-to-south power transfers on the AC and DC interties, transfers through Idaho to Utah and unusually high thermal generation in Wyoming and Utah – almost 10 percent of consumers in the West saw their power go out for at least a few minutes.

Then, on Aug. 10, more than 7 million people across the West lost power. This much larger outage began in the Northwest when a BPA line in the Willamette Valley contacted fast-growing filbert trees. Then generators at McNary Dam on the Columbia River erroneously tripped off. The loss of the Keeler-Allston #1 500-kilovolt line initiated a cascading outage condition that resulted in multiple transmission lines relaying out of service and the loss of over 28,000 megawatts of load. That represents approximately half of the summer peak load in California.

This disturbance had a significant impact on defining safe and reliable operation of the transmission system.

That event was eclipsed when, on Aug. 14, 2003, more than 50 million people lost power across parts of the Midwest and northeastern United States and Ontario, Canada. This outage began when three FirstEnergy, Ohio, 345-kilovolt lines contacted overgrown trees. It cascaded into the biggest blackout in North American history.

Utilities in the West learned a great deal from the 1996 outage. The Western Electricity Coordinating Council initially reduced ratings of the Pacific Northwest-Southwest lines connecting the Northwest and California. BPA installed stability controls known as remedial action schemes, added shunt capacitors, improved equipment at dams, and, eventually, added new lines and substations to reinforce its grid.

A national investigation team concluded that the causes of the 2003 Midwest/Northeast outage came down to poor vegetation management, inadequate awareness of the situation at the local utility and failure of reliability organizations to provide effective diagnostic support. Utilities involved in the blackout are still responding.

As a result of these disturbances, the need to set limits to prevent future cascading outages took a much higher priority. (See graph on page 18 showing how computer modeling of the system needed improvement.)

But by the 1980s, transmission infrastructure expansion had slowed as major resource development was largely completed. At the beginning of the decade, the regional economy was hit hard by a sustained recession and large electricity rate increases due to a less-than-successful nuclear-building program. Demand for electricity hit a plateau from 1979 to 1986, and large capital investments were put on hold or terminated. Capital investment in the transmission system was no exception.

The situation changed sharply in the 1990s as regional loads rebounded coupled with growing concerns for winter reliability in the Interstate-5 corridor. Population and economic growth along with a growing dependency on electricity-intensive tools and amenities increased pressure on electricity delivery systems. With BPA's access to capital limited, the focus of transmission investment shifted to lower-cost system enhancements that involved system controls and communication, including system reactive devices and Remedial Action Schemes (RAS).[7] Such schemes included actions, such as generator dropping, to protect the transmission system against cascading outages or other major disturbances. To a large extent, the previous investments in long-distance transmission made these lower-cost improvements possible.

Throughout the 1990s, BPA's increasingly stressed transmission system was improved and reinforced with stopgap approaches that provided short-term fixes, albeit very effective ones for that period. Ironically, some of these fixes may have put the system in a more vulnerable position today because they have allowed the system to be run "closer to the edge." For example, the increased use of capacitors for reactive power creates brittleness in the system since they can mask a problem so that when it does occur, it can be sudden (voltage collapse) instead of gradual change (voltage decay or decline). Similarly, increased use of RAS has allowed operators to run the transmission system harder. Without such schemes, ratings on many flowgates would be considerably lower, especially on the Southern Intertie. Increased use of system monitoring (temperatures, sag, loadings, etc.) also has allowed operators to reduce margins.

By the late 1990s, it was evident that relying solely on lower-cost or "easy" fixes had, for the large part, been exhausted. BPA initiated a major infrastructure construction program that continues today. Since 2001, BPA has invested more than $1 billion in transmission projects to maintain reliable service to loads, meet current obligations and restore some operating margin. Projects completed include three new 500-kilovolt lines, a new 500-kilovolt substation, two lower voltage lines, large new transformer banks in both the Puget Sound and Portland metropolitan areas, several local load service projects and the modernization of the Celilo Converter Station near The Dalles Dam. At Celilo, BPA replaced 30-year-old mercury arc valves with state-of-the-art, solid-state converters. However, building to serve load and building to relieve congestion are two different things. (See map of "BPA's infrastructure projects" on page 8.)

BPA also initiated a non-wires solutions project in 2003. This initiative is exploring ways to reduce peak load when required.

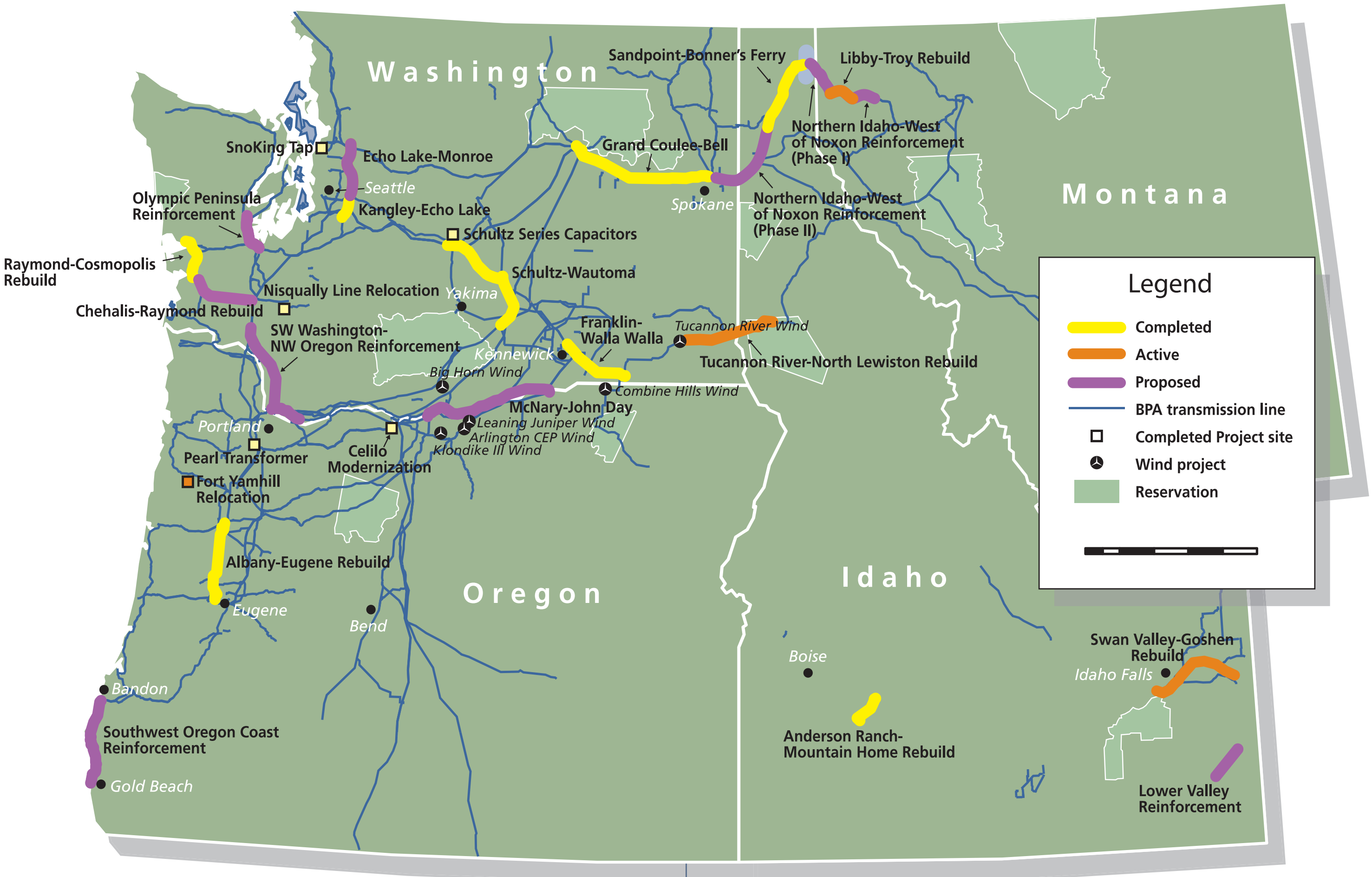
Why is the problem getting worse?

The 1990s ushered in rapid changes in both the hydro system and West Coast power markets that led to changes in the way the grid is used. Many of these changes were not envisioned when the system was built and now test its resilience. These changes include the following developments.

- Application of reliability standards has been tightened, especially after the West Coast July/August 1996 and the East Coast August 2003 cascading blackouts. These events prompted transmission operators, including BPA, to operate their grids more conservatively. One result has been that, over time, tighter limits on flowgate loadings have limited system flexibility. (See box on "WECC reliability criteria" on page 12 .)
- Changes in the operation of the hydro system mandated by the Endangered Species Act (ESA) shifted generation from

7 Reactive devices include static VAR compensators, shunt reactors, series capacitors and synchronous condensers. RAS employs high-speed electronic controls that allow the transmission system to quickly analyze and respond to problems by automatically dropping generators or load, applying a large braking resister to slow accelerating generators and other measures. RAS arming is monitored 24 hours a day.

BPA infrastructure projects



the Snake River and Lower Columbia River to the Upper Columbia, which significantly increased transmission system loadings in the north-to-south transmission corridors (especially the I-5 corridor). At the same time, the ESA-driven changes limit the flexibility of the hydro system to redispatch as needed to redirect power flows across the system.

- Emergence of the Federal Energy Regulatory Commission's (FERC) Non-Discriminatory Open Transmission Access order in 1996 has resulted in a significant increase in the number of transmission users and a dramatic increase in transmission schedule complexity.
- Market deregulation in California gave rise to expanded Western power trading and increased demand for access to transmission.
- British Columbia power exports into and through the Pacific Northwest to California increased. At the same time, the Northwest began meeting its obligation to return Canadian Entitlement power. (See box on page 9.)
- Generating capacity in the I-5 corridor has increased, which, while beneficial for meeting winter loads in the Pacific Northwest, now contributes to summer congestion as this power flows to California to meet that state's peak load season.

The Canadian Entitlement

The U.S. portion of the Columbia Basin has limited storage capacity, which limits flood control and firm power generation capability. To address this, the United States and Canada negotiated the Columbia River Treaty in 1961 to provide for power and flood-control-related storage in the Canadian portion of the basin. British Columbia Hydro and Power Authority built dams that can store 15.5 million cubic acre-feet of water and provide significant flood control.

Under the treaty, the United States must deliver to Canada half the benefits of firm power produced in the United States from the water stored in Canada. This "Canadian Entitlement" power now consists of about 465 to 570 megawatts of usable hydroelectric energy and 1,300 to 1,400 megawatts of dependable capacity. The power is generated at federal and nonfederal Columbia River dams.

Canada sold its Entitlement power to Northwest utilities for 30 years. In 1997, all parties agreed on the allocation of responsibilities for returning Entitlement power to Canada. BPA provides 72.5 percent of the Canadian Entitlement energy and all the capacity; non-federal utilities that own mid-Columbia dams provide the remaining energy. BPA delivers Canadian Entitlement power at Nelway, B.C., north of Spokane, Wash., and at Blaine, Wash., north of Seattle.

Canadian Entitlement power returned to Canada is often resold to U.S. utilities in the Northwest, California and other states. The flow of such power is, therefore, a factor in BPA's transmission activity.

- ✦ The Northwest's summer power demand in the I-5 corridor has increased significantly, primarily as a result of large increases in summer air conditioning load. Increasingly, serving this load on summer peak days requires transmission capacity that formerly was available to support surplus power sales to California.
- ✦ Direct-service loads declined markedly as a number of Northwest aluminum smelters shut down or curtailed operations. The loss of smelter load changed how power flows on the transmission system. Generation that normally served those large loads is now available to serve loads elsewhere. This creates more congestion in some locations, while relieving it in others. (See boxes on how "How Northwest loads are changing" on page 11 and on "West of Hatwai" on page 10.)
- ✦ Additional gas-fired generation across the Pacific Northwest grid, much of it merchant-owned, has increased dramatically. Because a number of these plants run only when power prices are high enough to cover fuel costs, they are more likely to rely on nonfirm transmission.
- ✦ With many more generators, marketers and multiple control areas in the region, the complexity of communication links affects the ability to respond to crisis in a timely manner.
- ✦ The percent of the region's power production met by federal resources is shrinking. And, as it shrinks, BPA's flexibility to control conditions adversely affecting the reliability of the Northwest grid by what generation is turned on or off is also diminished.
- ✦ Separation of BPA's power and transmission functions into two independent businesses increased the degree of complexity in managing the operation of the regional hydropower system.

West of Hatwai

The West of Hatwai flowgate defines a group of transmission lines over which power moves west from the Spokane, Wash., area and northern Idaho to central and south-central Washington. During the West Coast energy crisis in 2000-2001, large aluminum smelter loads in Montana and Spokane went away. Power generated in Montana that formerly served these loads then moved west to find replacement markets. The result was overloading of transmission lines west of Spokane. New transmission investments (Coulee-Bell 500-kilovolt line) by BPA and by Avista Corp. have helped ease this congestion.

- As the region approaches load-resource balance, there are increasing requests from utilities and power producers to connect generators to the transmission grid, particularly wind. Integration of new generation creates new uses of the transmission system. To the degree they rely on nonfirm transmission, intermittent resources produce additional challenges because their generation and dispatch are variable and more difficult to predict. Given the region's – and indeed the nation's – interest in developing renewable resources, it will be important to address these challenges.
- While many transmission limits are the result of new uses of transmission, others may have existed previously but had not previously been identified as a risk. As an example, the simultaneous loss of two nuclear units in the Southwest had not been considered a credible contingency prior to the Aug. 10, 1996, disturbance.[8]

What role does nonfirm transmission play?

At the time the Federal Energy Regulatory Commission issued its proforma Open Access Transmission Tariff (OATT) in 1996, BPA embraced the principle of non-discriminatory open access transmission and adopted its own open access tariff. BPA's OATT grants priority rights to firm transmission access and subordinates nonfirm transmission schedules to reservations and schedules for firm access. Some power sellers without firm transmission contracts rely on nonfirm transmission to market power from their generators. Still other power sellers that do have firm point-to-point transmission to a certain market choose, on occasion, to sell their power to another market on a nonfirm basis. These transactions may use transmission in ways for which the system was not planned or designed. While the distinction between firm and nonfirm was always a part of prior BPA transmission tariffs, it was not a critical distinction in the past because there was rarely a need to limit access except at the interties.

Although BPA adopted the OATT, the agency has found it is difficult to implement a meaningful distinction between firm and nonfirm transmission schedules on the Pacific Northwest grid

8 The Aug. 10, 1996, disturbance resulted in a re-evaluation of what outages should be considered for studies. There had been a near simultaneous loss of two of three nuclear generator units at Palo Verde in Arizona. This had not caused problems on the transmission system, but it raised the question of whether it could under the right conditions. Studies done for loss of two nuclear units at Palo Verde and Diablo Canyon and San Onofre in California indicated that these outages could cause problems on the California-Oregon Intertie (COI). The loss of two Palo Verde units is the largest generation loss and the most limiting. As a result of these studies, the loss of two Palo Verde units now is considered a credible contingency and is often the most restrictive contingency when determining COI limits.

How Northwest loads are changing

The West Coast energy crisis of 2000-2001 led to a large reduction in the Pacific Northwest's aluminum smelter load. These loads have the characteristic of reducing when voltage reduces, which tends to protect the system during contingencies. Although the Northwest is still a winter peaking region, air conditioning is pushing the summer peak load up. Unlike smelter loads, air conditioning loads have the characteristic of staying constant as voltage reduces. Thus, the combination of reduced aluminum smelter load and increased air conditioning load has reduced the percentage of the region's voltage-sensitive load. This makes the transmission system less robust after a transmission outage and increases the risk of voltage stability problems.

in hourly markets. Instead, BPA has moved into the open access era without adequate systems and procedures in place to implement the tariff's priority access rights or to anticipate or distinguish in real time the relative contribution of firm and nonfirm schedules to actual powerflows. This greatly limits BPA's ability to effectively manage physical congestion on the system as contemplated under the tariff. It also means that, in practice, nonfirm transmission can be scheduled with the same reliability as firm transmission across the network flowgates.

The effect of this practice has had its benefits as well as drawbacks. On the positive side, accepting all schedules has promoted an efficient power market. However, the problem today is that the practice now compromises BPA's ability to manage system reliability. It also distorts the transmission market by in essence discounting the effective price of nonfirm transmission giving it virtually the same value as firm transmission. This has prompted buyers to rely more heavily on nonfirm transmission than may have been the case otherwise, and it has likewise reduced the chance that the demand for firm transmission would be an effective signal to BPA to build incremental transmission supply. Today, under the existing rules, generators have relatively little need to hedge their access to the transmission system with firm transmission contracts.

And, so long as nonfirm transmission across the network flowgates of the Pacific Northwest grid is scheduled without constraint, BPA's transmission operators have no forewarning of the generation dispatch patterns that will result in powerflows exceeding the OTC limits of flowgates. As a result, the primary underlying cause of most actual and potential congestion on BPA's transmission network is the unlimited dispatch of generation by the market using nonfirm transmission.

How is congestion handled today?

Once an alarm goes off indicating that a transmission flowgate is overloaded, dispatchers must act in real time to take corrective measures to control powerflows. They have limited information, limited tools and limited time to adjust flow patterns to restore the transmission system to a reliable operating condition. The tools they do have are often not optimal for relieving the constraint. These tools also can be disruptive to the power markets as customers are forced, in a very short period, to try to reconfigure transmission and power deals.

The effectiveness of the existing methods to control flows of power varies depending on the magnitude and the location of the OTC exceedence and the availability of the tools. Bypassing series capacitors is one of the tools used to change powerflows because it changes

WECC reliability criteria

- A transmission provider has 20 minutes to bring flows to within OTC limits if the flowgate is limited by voltage or transient stability capabilities.
- A transmission provider has 30 minutes to bring flows to within OTC limits if the flowgate is limited by thermal capabilities.
- If these time limits are exceeded, the OTC exceedence becomes a sanctionable OTC violation under the WECC Reliability Management System.
- The E-tag system will be the primary tool used to communicate emergency outages or curtailments to interchange transactions.

the impedance of a network element.[9] But while this can help one flowgate, it can also aggravate another flowgate, so it is not always effective. Redispatch of federal power depends on river constraints, and it too is not always available as an option and may not be tariff compliant.

Under WECC criteria, operators have 20 or 30 minutes to bring the system back within OTC limits, depending on the nature of the problem, before a sanctionable violation occurs. Substantially different responses may be needed to stay within that time limit. The less time dispatchers have, the more likely they are to call for a greater degree of curtailment to ensure they are meeting system requirements.[10] For example, a 50-megawatt OTC exceedence may require a 150-megawatt schedule curtailment when there are 15 minutes before it becomes an OTC violation, but it may require a 300-megawatt schedule curtailment when there are only five minutes left to respond. This is because different types of generators have different ramp rates (how fast they can increase or decrease output), which will affect how generation changes are implemented.

The effectiveness of redispatch and schedule curtailments also will vary depending on the location of the generation. Typically, the farther away generation changes occur from the constrained flowgate, the less effective they are. For example, a 100-megawatt overload on the I-5 corridor near Portland, Ore., would require at least 500 megawatts of generator reduction at Grand Coulee Dam and, depending on the replacement resource, could require an even greater reduction.

With few exceptions (for example, external interconnections such as West of Hatwai), the region's robust transmission system was historically able to accommodate changing markets without the need to limit the economic dispatch[11] of regional generation. Economic dispatch as used here means meeting demand for power with the most cost-effective mix of generation. BPA limits the amount of long-term and short-term[12] firm transmission it sells based on its flow-based Available Transfer Capability (ATC) methodology. (See box on "The ATC methodology" on page 13.) However, BPA places no limits on the use of hourly transmission on the network, so in practice BPA continues to operate its network by accepting all schedules.

9 Impedance is a characteristic of an electrical circuit that determines its hindrance to the flow of electricity. The higher the impedance, the lower the current.

10 A larger schedule curtailment request will presumably be spread over a larger number of generators. While the generators may have slow ramp rates and individually react slowly, a larger number of generators will react swifter in aggregate.

11 Section 1234(b) of the Energy Policy Act of 2005 defines "economic dispatch" as the operation of generation facilities to produce energy at the lowest cost to reliably serve customers, recognizing any operational limits of generation and transmission facilities. The act requires the Federal Energy Regulatory Commission to convene joint regional boards to study "security constrained economic dispatch," among other things, and make recommendations to FERC. In the order initiating the regional boards, FERC defined "security constrained economic dispatch" to have the same meaning as "economic dispatch" provided in section 1234(b).

12 Transmission service in annual or daily increments, respectively.

The ATC methodology

In 2003, BPA's Transmission Business Line put in place a methodology for defining its long-term firm transmission inventory on its network. The purpose was to make more efficient long-term use of the transmission system. The methodology used was called the Available Transfer Capability – or ATC methodology. In 2005, after a public process, BPA modified the methodology by refining modeling assumptions that resulted in additional available transfer capability across certain flowgates that had been particularly constrained. For example, the changes now model the return of the Canadian Entitlement more accurately and remove certain nonfirm flows to the Southern Intertie. The changes also reduced redundant capacity margins being withheld across certain flowgates that were near or parallel to each other.

What tools are being used?

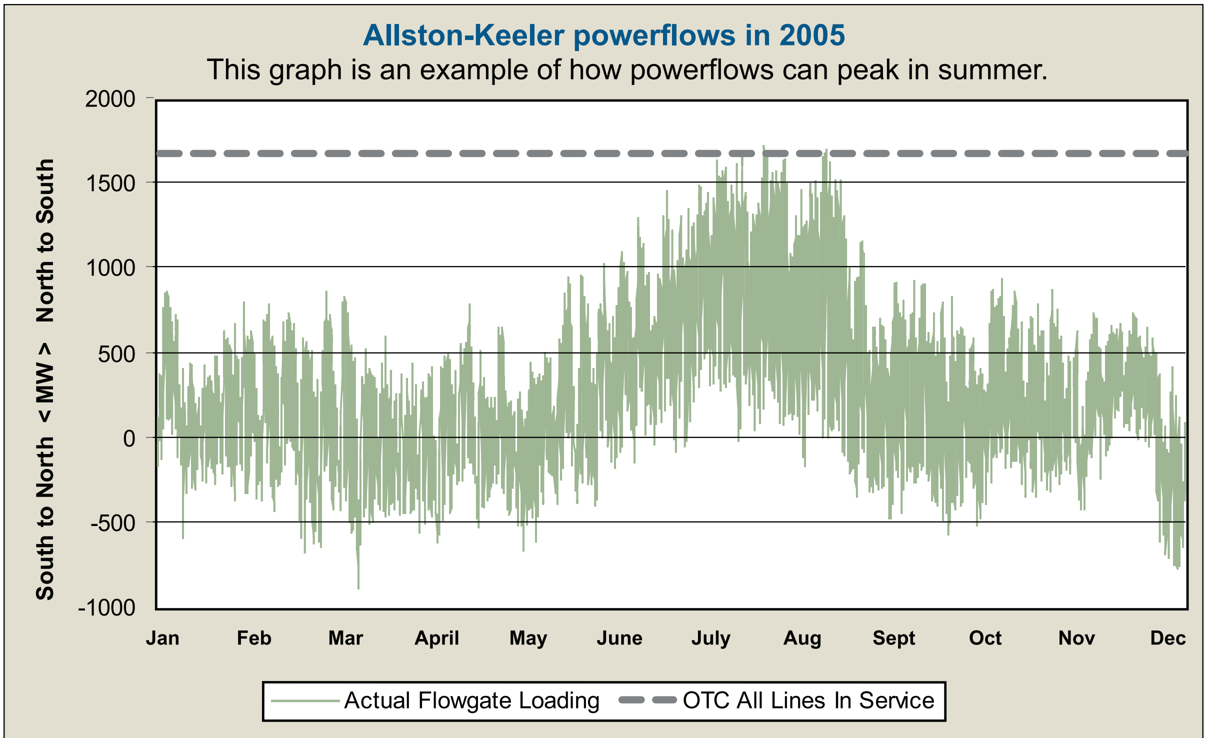
In an effort to either avoid or recover quickly from emergency situations where flowgate loadings exceed OTC, BPA has implemented a number of activities in recent years to reduce network flowgate loadings. These actions, along with their tradeoffs, are described below. Even if these tools were adequate to ensure reliability, which they are not, the costs that the current approach imposes on BPA's transmission business operations and Pacific Northwest power markets are unacceptable. BPA does not expect to eliminate current tools where useful, but would expect, through better and more repeatable approaches to congestion management, to minimize the use and consequent impacts of these tools.

Restricting maintenance outages: To protect against potential congestion, BPA has increasingly restricted its flexibility to schedule routine and emergency maintenance outages. This is done to protect against potential congestion that might result from reduced OTCs if key transmission lines or other equipment were temporarily out of service. This practice increases maintenance costs, reduces efficiency of field maintenance crews, and – to the extent maintenance is deferred – reduces system reliability. For example, spacer dampers on BPA's 500-kilovolt lines are rapidly wearing out, increasing the risk of damaging conductors until they fail and drop, which has happened. BPA has a spacer replacement backlog of 10 to 12 years in part because of limited ability to schedule required outages.[13]

Curtailing firm intertie schedules: This action is often only marginally effective largely because many of the intertie schedules curtailed involve transactions from generation sources that do not contribute to a specific congestion problem on the network. This may mean that as many as 1,500 megawatts of intertie transactions must be curtailed to gain 100 megawatts of network relief. Also, BPA's current practice of curtailing firm intertie schedules to reduce network schedules is not consistent with the curtailment priority in the tariff or with NERC product priorities[14] because this does not

13 The 500-kilovolt system requires replacement of bundle spacers that have reached their end of life. Replacement of the 285,000 remaining spacers is scheduled at the rate of about 24,000 units a year over the next 12 years.

14 NERC industry-standard Product Priorities (ranked lowest to highest, where lowest priority is curtailed first):
- Priority 0 Next-hour Market Service – NX
- Priority 1 Service over secondary receipt and delivery points – NS
- Priority 2 Nonfirm Point-to-Point Hourly Service – NH
- Priority 3 Nonfirm Point-to-Point Daily Service – ND
- Priority 4 Nonfirm Point-to-Point Weekly Service – NW
- Priority 5 Nonfirm Point-to-Point Monthly Service – NM
- Priority 6 Network Integration Transmission Service from sources not designated as network resources – NN
- Priority 7 Firm Point-to-Point Transmission Service – F and Network Integration Transmission Service from Designated Resources – FN



ensure that all contributing nonfirm schedules have been curtailed prior to a firm cut.

In the long run, frequent curtailments of firm Intertie customers decreases the value of holding Intertie capacity and threatens the economic viability of the Interties. The Interties have been and are expected to continue to be a significant source of economic benefits to regional consumers.

Bypassing series capacitors and phase shifters: Bypassing series capacitors increases the impedance (hindrance to the flow of power) of the transmission line. Because power tends to flow on the path of least impedance, increasing the impedance reduces the power flowing on the line. A simple analogy is a freeway. Bypassing the series capacitors is similar to closing a lane on the freeway to redirect traffic (in this case, megawatts) to alternative routes. Phase shifters are specially designed transformers that are used to control the flow of power on parallel paths of transmission.

Redispatch of the federal hydro system: BPA's Transmission Business Line (TBL) has an arrangement with BPA's Power Business Line (PBL) to redispatch federal generation under certain limited conditions. Specifically, if TBL determines that a redispatch of federal generation is necessary to maintain the reliability of the system, PBL has agreed to implement such redispactch in real time to the extent possible and for a period not to exceed 100 minutes. After 100 minutes, no redispatch is allowed until all nonfirm schedules have been curtailed across the constrained path. TBL pays $1.5 million under current rates for the redispatch of federal hydro generation. This arrangement has proven somewhat effective in the past, but the effectiveness has declined as increasing restrictions are placed on the hydro system's operational flexibility. Also, federal generation does not exist in many locations where congestion occurs. Some portions of the grid, including most of the I-5 corridor, have no federal generation.

Real-time schedule curtailments: This approach notifies certain customers that they need to curtail; that is, reduce their transmission use during an hour. Because curtailments force customers to make other power and transmission arrangements to preserve service to load, BPA's current practice of curtailing schedules when real-time system emergencies occur can increase costs to consumers. Adequate notice of impending transmission constraints would allow orderly dispatch of alternative generation arrangements during preschedule to achieve the greatest dispatch efficiency. Emergency schedule curtailments, on the other hand, can leave the market with minimal redispatch alternatives, leading to higher costs and significant financial penalties.

Additionally, at times, schedule curtailment is not effective. Path 18, which goes from Montana to Idaho, is an example. In the summer of 2003, when flows on this path exceeded OTC, schedules over the path were cut. However, the replacement schedules put in place did not fundamentally change the resources being dispatched and therefore did not substantially relieve the problem. Changes to schedules alone don't address overloading; generation has to move as well.

Higher costs can result from the need to dispatch expensive rapid-response peaking units, while lower-cost generation with longer start-up requirements remains idle. In cases where alternative commercial arrangements cannot be made in time, customers whose schedules are curtailed can suffer liquidated damage penalties for failure to deliver power.

Load shedding: As a last resort, if all other actions fail, the dispatcher will implement selective load-shedding protocols to protect the system from the potential of cascading failures.

One question in any discussion of congestion is how other parts of the country deal with the problem. Two-thirds of the U.S. load is served by providers participating in regional transmission organizations, and this influences approaches to congestion. For a report on what others are doing, see Appendix C, "How others manage/relieve congestion."

What are the economic impacts?

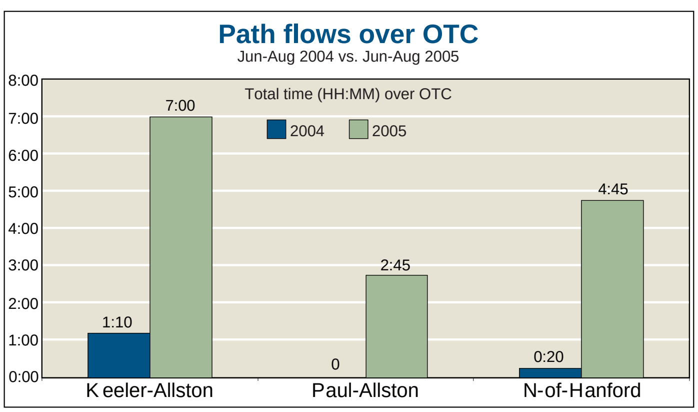
Currently, BPA's transmission network is adequate under NERC and WECC criteria to deliver power to all regional loads under peak load conditions from existing generation that holds firm transmission. To ensure adequacy, BPA engineers conduct annual studies of the system. The increasing congestion on the transmission system is seldom due to power deliveries to regional and extraregional loads from generators that hold firm transmission. Rather, congestion primarily coincides with the additional deliveries of power from generation without firm transmission to simultaneously meet high regional loads and to make large exports out of or through the region. This generation that has elected not to have firm transmission contracts is most susceptible to future schedule curtailments to manage congestion.

The tariff provides that actions to relieve this congestion require first curtailing nonfirm transmission schedules or redispatching network resources to reduce powerflows across the constrained flowgate. While this curtailment or generation redispatch may not disrupt service to loads or affect the availability of power, it may affect the cost of power because it may limit which generators can operate.

The cost to redispatch resources and/or arrange for other power supplies can range from zero up to the full price of replacement power. When the frequency of such redispatch is low and the magnitude of redispatch is limited, the costs to the power market (and ultimately consumers) are typically low. This reflects the incremental cost of dispatching a higher cost resource or, for the hydro system, managing flows in a less than optimal fashion. At times of peak use, these costs can be high, especially if the tradeoff is between hydro and natural gas. However, while the cost to the power markets overall of occasional congestion is often small, the effect on individual utilities and generators can be relatively high due to the redistribution of power sales revenues. The boxes on page 17 provide more details on the cost impacts of congestion to hydro and thermal generation.

What can be done?

The dramatic increase in OTC exceedences in the summer of 2005 are strong indications that existing mechanisms may no longer be adequate to ensure reliable transmission system operations. OTC was exceeded a total of seven hours on the Allston-Keeler flowgate in 2005 compared to only one hour and 10 minutes during that period in 2004. OTC was exceeded on the North of Hanford flowgate for almost five hours in the summer of 2005, compared to 20 minutes in 2004. (Also see Appendix A on "OTC exceedences.") These events make it increasingly evident that BPA's current transmission scheduling practices promote an unacceptable risk.



A reasonable question is what is the specific risk of a cascading system outage under the current approach. BPA designs and operates the system to be safe and reliable for events identified in the reliability criteria and to provide a margin to accommodate unpredictable events. However, BPA cannot quantify the risk of a cascading outage being triggered while the system is stressed above OTC limits. What can be said with authority, is that the grid's exposure to the risk of such events is increasing. This is quantified by the numbers that show increases in OTC exceedences and increases in the duration of cumulative exceedences. (See boxes on page 3 and on this page.)

Any solution to the issue of congestion management must be guided by the three principles laid out in the box on page 4. These address reliability and cost, as well as tariff rights and obligations. Approaches to solving congestion likely will raise a number of questions. These include, but are not limited to, the following:

- If it is known that congestion will occur, what action should be taken to prevent it?
- How much congestion is too much?
- What is the cost of congestion and how much should be invested to fix it?
- What business practices and tools should be developed to forecast and to prevent congestion?
- What financing arrangements and cost recovery protections are appropriate if BPA builds infrastructure to reduce congestion?
- Is the solution compliant with the tariff or should the tariff be changed to facilitate a solution?
- How do we define cost impacts associated with the various options?
- How do we address the various impacts on customers and consumers?

Below are five basic approaches to addressing the growing issue of congestion. None

Costs to redispatch hydro generation

Hydro generation represents a significant amount of Northwest generation when congestion occurs on the BPA network. To relieve congestion, the hydro operator will attempt to reduce generation upstream of the congestion and increase generation downstream of the congestion.

This action changes the optimal operation of generation among hydro projects and affects the future amount or timing of generation. Hydro operators establish their generation patterns to maximize the output of the generation meeting their loads and the value of their surplus marketing. Such redispatch results in shifting future hydro generation to less valuable hours or reducing the amount of energy that can be produced by a given volume of water (due to sub-optimal water management). For example, if water releases are curtailed at an upstream project on heavy load hours, then to ensure adequate water is released, more water and resultant power may need to be generated on light load hours when the constraint is gone. This change in operation can be a significant cost. The cost can range from $1 a megawatt-hour to over $100 a megawatt-hour, depending on the time of year and the impact on generation patterns.

In the unlikely event that hydro redispatch were to result in forced spill, the cost would be reflected in the full cost of the replacement resource, typically a gas-fired resource with an incremental cost ranging from $30 a megawatt-hour to $100 a megawatt-hour, depending on gas prices. In the event the redispatch occurs on an hour when no additional hydro generation is available for dispatch downstream of the constraint, then the cost would be the difference between the full cost of the downstream replacement resource and the value of the surplus sale or avoided purchase when the water is released at a later hour. The real-time price for downstream replacement generation is often based on the California Independent System Operator price plus transmission and losses to the BPA system.

Costs to redispatch thermal generation

When congestion relief requires the redispatch of thermal generation, the cost to the power system is the difference between the incremental cost of operating the replacement resource downstream of the constraint and the avoided cost of the upstream resource that is turned off. In addition to these variable costs, the party with the redispatch obligation may have a standby cost for the generator downstream of the constraint in order to move the generator from cold standby to ready to generate on short notice.

The incremental fuel cost is primarily a function of the differences in fuel cost and conversion efficiency (heat rate) between the planned generator and the replacement generator. Except for a few combustion turbines that can ramp up from cold start to actual generation in 10 minutes, there is either a standby charge each hour a generator is potentially needed to relieve a constraint or a lost surplus sales value for holding capacity in an operating generator to address a potential congestion constraint.

In practice, such costs can range from $10 a megawatt-hour to $100 a megawatt-hour, but are typically around $30 a megawatt-hour in the Northwest. These costs assume a combined-cycle combustion turbine must be replaced with an older quick-start simple cycle combustion turbine of lower efficiency. Generators may face additional costs when rearranging their fuel supplies for both plants. In the unusual circumstance that the resource turned off is a coal resource, the cost to redispatch would be higher. If there is no quick-start combustion turbine in the Northwest downstream of the constraint, the real-time price is based on the California Independent System Operator price plus transmission and losses to the BPA system. The longer the lead time given the generator subject to redispatch, the more likely the generator can secure a lower cost redispatch alternative in the market.

precludes a further approach that combines elements of one or more of the approaches listed as well as new ideas. Each approach is presented conceptually, not in detail or with any degree of fine-tuning. Some options have serious tradeoffs, such as complexity and cost, and these are discussed as well. In looking to solutions, BPA is especially interested in what customers and other stakeholders have to say.

Approach 1: Curtailment with enhancements

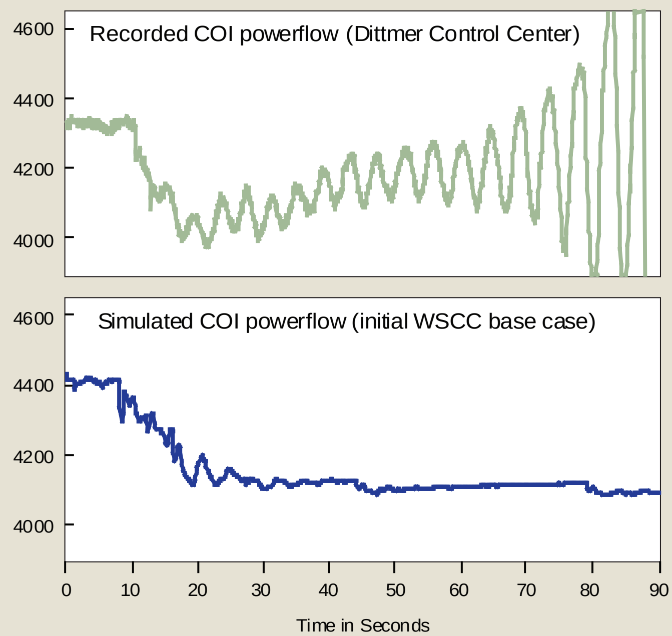
This approach recognizes congestion will happen and that curtailments will be necessary. It focuses on dealing with congestion when it happens. To improve on the status quo, dispatchers would need better tools, such as curtailment calculators[15] and other flowgate-specific tools to enhance their ability to deal with network problems. The current tools are crude and shift responsibility to others when transmission is curtailed, forcing the involved parties to find the resources (or load reductions) to keep the system in balance. The Path18 example cited in the section "What tools are being used" is an example of why this doesn't always work. The replacement schedules put in place when the path was overloaded did not fundamentally change the resources being dispatched.

Some ability to reduce congestion could come from use of more dynamic nomograms (operating rules that determine OTC based on current system conditions). The OTC limits

15 A curtailment calculator is a tool used to curtail/modify previously identified schedules to reduce loadings across a flowgate. Schedules are identified based on their flow contribution to lines crossing the flowgate. These are calculated using path utilization factors (PUF), which are based on the power system's physical configuration and the impedances of its various components. The calculator is triggered by the dispatcher during an overload. The dispatcher enters the amount of the overload, and the program outputs those point-to-point schedules that must be curtailed pro rata to alleviate the overload. These tools are for use only in real time; they are not designed to predict flowgate loadings or preemptively manage flows. Currently, only one of the 10 internal flowgates has a curtailment calculator.

Tools and assumptions evolve

Tools and assumptions are constantly evolving as study results and real system responses identify new problems. When the actual system response is worse than studied results, study modifications can result in more restrictive operation. See graphs below comparing the Aug. 10, 1996, blackout actual system response to a simulated response. The blackout is described in the box on page 6.



usually consider worst-case scenarios, and static OTCs are issued conservatively to ensure reliability in accordance with current operating standards. However, these static OTCs can leave additional capacity on the table, or lead to unnecessary curtailments, when actual real-time system conditions do not match the worst-case assumptions used to determine the OTC.

Since curtailment remains inherent in this approach, BPA may consider modifying its curtailment priority procedures. Such modifications would be designed to simplify congestion management for dispatchers and schedulers and to enhance the value of firm transmission on the network. If this approach were to call for adopting a curtailment priority that modifies the priorities currently set forth in the tariff and used by the North American industry, it likely would require FERC and NERC approval.

Pros and Cons: From the perspective of the power market, the advantage of this approach is that BPA would continue to accept all schedules up to the hour and would not require more detailed information from customers on point-of-receipt or point-of-delivery. The disadvantage is that it places BPA transmission schedulers, dispatchers, operators and customers in a more heightened alert status and continues to leave the system vulnerable when contingencies occur. And without tools to identify transactions that effectively relieve the constraint and distinguish curtailment of nonfirm transmission schedules from firm schedules, it may not conform to an open access tariff that calls for such a distinction.

Also, it does not place any higher value on firm over nonfirm access to the system. A high volume of nonfirm transactions will lead to continued "spiky" use of the system, whereas long-term firm contracts lead to a system that has higher predictability and lower volatility. Also, transmission costs and consequences of curtailment may not be shared equitably among transmission users.

Approach 2: Commercial redispatch

Commercial redispatch is a structural approach to congestion management that is designed to give the transmission dispatcher direct control over non-affiliated generators for the purpose of redispatching generation to relieve congestion.

Under the commercial redispatch approach, the transmission provider relieves perceived impending or real-time congestion by directing a generator(s) upstream of the congestion to "turn off" and generator(s) downstream to "turn on." All schedules are kept whole so no commercial transactions are disturbed. The generator that is turned off pays the transmission provider based on the cost savings from not operating. The transmission provider must in turn pay the generator that turns on based on the generator's incremental cost of producing power plus a profit margin. In addition, there may be a capacity cost associated with the option to call on a generator to provide redispatch.

The net cost of a commercial redispatch program is the transmission provider's cost to dispatch generation or reduce load less revenues from generators that are relieved of their obligation to generate, plus any fixed costs associated with firm options to redispatch participating generators or to control loads. These costs typically are recovered from scheduling parties that do not have transmission rights across the congested path; that is, nonfirm users of the system. The transmission provider can also employ this approach to increase sales of firm transmission. In such a case, the transmission provider would absorb these costs or charge them directly to the purchaser of the incremental firm transmission.

Pros and cons: A major advantage of this approach to constraint management is that it enables the transmission provider to accept all schedules while preserving reliable operation of the system, and it supports market actions to achieve economic dispatch. A major impediment is the complex contractual, financial and settlement arrangements required to implement an effective system. It would require negotiation and drafting of numerous highly complicated contracts as well as the development of sophisticated tracking and billing systems. This approach on its own would also still be reactive and would provide little to no knowledge of when congestion would occur or which schedules should be cut to get relief if the redispatch is insufficient.

Approach 3: Minimizing congestion proactively

This approach seeks to anticipate and avoid congestion rather than relying on corrective action when congestion occurs. It would require procedures and tools to predict congestion along with approaches and tools to limit use of the system to minimize congestion. There are several potential ways to go about this. All congestion management approaches result in adjustments to projected generation dispatch patterns before the hour of flow. While two methods are outlined under this approach to congestion, there may be other approaches or variations, and BPA is open to other ideas.

Method 1: Customers could provide schedules a day ahead with more detailed generation and transmission information. This would give schedulers prior knowledge of when the system might be overloaded so ATC can be calculated and posted each hour for all constrained paths. BPA would limit schedules to the available capacity on a path to avoid congestion. This knowledge would also make the development and implementation of a conditional firm[16] product possible. It would, however, require customers and BPA to make changes to their scheduling and accounting systems and could require increases in scheduling and forecasting staff.

Method 2: BPA forecasts a day or more ahead how the network will be used (loads and generation) without significant changes to BPA and customer scheduling systems. BPA would not accept hourly reservations and/or schedules when it appears likely that those schedules would result in exceeding the OTC on a flowgate. If BPA could predict flowgate overloads during the preschedule window and limit reserving and/or scheduling of transmission to flowgate limits, it could avoid many real-time congestion emergencies at minimal cost to the power markets. However, to the extent that forecasts aren't precise, this could result in artificially limiting access to transmission. This method could provide most of the benefits of the variant above, without the negative customer impacts.

Under both methods, unplanned or unexpected outages would continue to require a reactive response, but the prescheduling information would allow BPA to respect firm rights over nonfirm.

Whichever method is implemented, this approach would put procedures in place, along with supporting automated scheduling tools, to enable schedulers to anticipate congestion and take preemptive action. If BPA can predict congestion and implement relief that reduces nonfirm schedules when congestion occurs, the rights of firm transmission customers will have less exposure to emergency curtailments. When needed, firm curtailments would be targeted to effective transactions, consistent with the tariff, to minimize economic impacts on consumers. The congestion management system should also be designed to track, to the extent possible, the market's response to schedule curtailments and the cost to the power market of actions to relieve congestion.

Pros and cons: Congestion management focuses on preventing congestion before it happens and eliminating or minimizing incidents where the system exceeds industry standards for operating reliably. This in turn would maximize dispatchers' abilities to deal successfully

16 BPA has begun development of a new "conditional firm" transmission product that would allow long-term firm transmission capacity to be sold with the proviso that service could be curtailed during some parts of the year. This could allow use of presently underused capacity on critical transmission pathways. At the same time, it may give wind generators better access to transmission grids. Development of the product is currently "on hold," as BPA focuses on putting in place the scheduling and curtailment systems needed to implement the conditional firm product.

with any contingencies that could occur, thus assuring greater system reliability. Congestion management capabilities to protect against flowgate overloads due to unconstrained economic dispatch would also significantly restore flexibility to take system maintenance outages while minimizing impacts to the power markets. Maintenance outages would still be scheduled to avoid risk to service for loads and to avoid interfering with firm transmission rights.

Under Method 1, users would have to accept more stringent process requirements and possibly costs for retooling scheduling systems. BPA acknowledges that the degree of detail must strike a balance between providing actionable information to dispatchers while minimizing additional burdens on those using the grid. BPA is concerned about the potential impact on customers and adjacent transmission systems resulting from these changes. To better understand which options create the least cost to consumers, BPA is seeking comments from utilities and energy marketers about what costs they would expect to incur.

Approach 4: Infrastructure building

This approach calls for constructing sufficient new facilities so that congestion rarely occurs and curtailments are necessary only when there are extraordinary events. This has been BPA's approach in the past, and the agency has just completed a major infrastructure program to shore up reliability for meeting loads, particularly in the Puget Sound area and along the I-5 corridor. These projects were designed to ensure contractual commitments are met.

Pros and cons: Building additional transmission lines would certainly relieve congestion, but a system built to handle all congestion would be vastly uneconomical, because congestion does not occur all of the time or even most of the time. Building infrastructure is expensive, has environmental consequences and requires access to capital that BPA has only in finite supply.

Under FERC rules, BPA can require parties requesting long-term firm transmission service that requires expansion of the transmission system to provide the capital for the necessary facilities in advance, thus protecting existing ratepayers from the risk of such customer nonpayment. Also, through FERC's "Or Pricing" policy, when transmission expansion would otherwise increase transmission rates, those parties requiring the expansion may be required to pay incremental costs so that other ratepayers are shielded from rate increases caused by the investment. When BPA borrows for transmission expansion, the costs are typically spread among all transmission users who may or may not benefit from the increased flexibility and reduced congestion. Investments to reduce the cost of congestion for nonfirm use would

Costs of expanding the system for congestion

Due to the high cost of major transmission infrastructure, it is rarely beneficial to the power system to expand the transmission system to relieve occasional congestion that only affects opportunity sales of power in the surplus market.

An example of this can be seen by examining the instances of redispatch and schedule curtailments due to congestion in the I-5 corridor in summer 2005. In total, 11,200 megawatt-hours of hydro were redispatched and 3,500 megawatt-hours of thermal generation were redispatched.

Assume the transmission fix to relieve this congestion is the potential Paul-Troutdale transmission line (estimated to cost roughly $200 million). Ignoring any other benefits of building such a line, the cost to the power market of relieving the summer 2005 congestion with a new Paul-Troutdale line would be about $19 million per year for 35 years, or over $5,000 per megawatt-hour of congestion relief.

likely require a high expectation of power system cost savings from reduced congestion. The box "Costs of expanding the system for congestion" on page 21 illustrates the cost of building to reduce infrequent congestion.

Approach 5: Applying non-wires solutions

BPA defines non-wires solutions (NWS) as demand-side or power management practices that would defer or eliminate the need to pursue a transmission hardware improvement. BPA fully considers NWS when it analyzes new transmission or improvements to existing transmission.

While applications of NWS to congestion management may be limited, BPA believes NWS should be part of any discussion on congestion management issues.

Below are two examples of how NWS might be leveraged with strategies outlined above to alleviate congestion. These examples are not intended to be a fully inclusive discussion of NWS and congestion management, but are offered as an illustrative approach.

- Instead of curtailing transmission as described in Approach 1, implement controlled voluntary/contractually-agreed-to load curtailment in affected areas through NWS measures such as industrial demand response and/or direct load control.
- In combination with either Method 1or 2 described in Approach 3, using day-ahead forecasts and information on how the network will be used, BPA would call for load management through real-time response (direct load control) or day-ahead contracts.

Pros and cons: This is a leading edge application for non-wires that should be viewed as exploratory.

Potential design criteria for testing solutions

Solutions to congestion ideally might provide capability to:

- Enable posting of ATC values for the network hourly markets.
- Limit awards of transmission service when network capacity is limited.
- Identify transactions contributing to the loading of network flowgates.
- Address network constraints prior to the operating hour (real time).
- Curtail interchange transactions affecting the network via E-tags.
- Curtail transactions affecting the network in a tariff-compliant manner.
- Implement a conditional firm product on the network.
- Implement federal and nonfederal dispatch protocols.

What happens next?

For the near term, BPA is moving forward on strategies to help alleviate congestion this coming summer. For example, plans call for completing development and implementation procedures for a second I-5 curtailment calculator for the Allston-Keeler flowgate in addition to the existing Paul-Allston flowgate curtailment calculator. For longer-term solutions, BPA intends to engage customers in testing principles and criteria and shaping conceptual design for an approach to managing congestion. BPA plans to have a congestion management strategy by the end of this fiscal year and some form of congestion management in place by the summer of 2007.

It's possible that a longer-term solution to congestion may combine elements of several approaches including better tools for dispatchers along with some degree of firm redispatch, some type of predictive congestion management and potentially construction targeted to certain problem flowgates.

At this point, BPA's preferred approach is a combination of solution elements, especially if it includes an effective congestion management system. BPA recognizes the value of regional problem solving and intends to develop criteria for examining and evaluating potential solutions designed to achieve consensus. Some possible elements for consideration are listed in the box on "Potential design criteria for testing solutions" on page 22. Analysis of customer impacts and mitigation of such impacts will be an important part of any congestion management development.

One thing is increasingly clear. The operational policies and approaches to system expansion of the past cannot be sustained today. If the market continues to exploit the flexibility of unconstrained economic dispatch, either transmission system reliability will be seriously compromised or BPA (and thus ratepayers) will be forced to make large uneconomic investments in transmission infrastructure. Key decisions and actions are needed very soon if BPA is to continue to do its part to ensure a reliable, adequate, economic and secure transmission and power system, and to continue to maximize commercial use of the system.

A number of developments are on the horizon that could exacerbate the problem. There is a strong likelihood of increased congestion along the I-5 corridor with new resources coming on line. Also, new court-ordered constraints on river operation could further limit the ability of the federal system to redispatch to relieve congestion. The longer the problem of congestion goes unaddressed, the worse it will be.

It will be important for BPA customers and other stakeholders to become involved and support work to address the congestion issue. It is not a stretch to say that the Northwest grid is much like "the village commons." And, unless all who use the commons are aware that the current way it is used can't be sustained, then in a relatively short time it will serve no one very well.

Other efforts

Adequacy standards

In 2004, BPA developed a white paper called "Transmission Adequacy Standards, Planning for the Future." Following a comment period, BPA initiated a public process through the Northwest Power Pool to develop regional adequacy guidelines. This effort addresses both the reliability and economic dimensions of adequacy. Guidelines have been developed to address certain situations not covered by existing reliability standards. BPA and other utilities must decide whether they will voluntarily comply with the guideline. The Power Pool is addressing further issues.

Non-wires alternatives

BPA sponsors a Non-Wires Round Table made up of industry, utility and environmental representatives working to make non-wires solutions viable to the Northwest. As part of this effort, in 2004 BPA began funding pilot projects that would allow consumers to curtail energy use during periods of heavy electricity use. These projects include directly controlling irrigation pumps, appliances, and heating and ventilation systems.

ColumbiaGrid

BPA is participating as a sponsor in a transmission organization called ColumbiaGrid. Other sponsors include Chelan County Public Utility District, Grant County Public Utility District, Puget Sound Energy, Seattle City Light and Avista. The group was set up to press for an integrated approach to the use and expansion of the Northwest's interconnected transmission system to substantially improve the operational efficiency, reliability and planned expansion of the transmission grid. The effort is focusing initially on (1) planning and expansion, (2) independent market monitoring, (3) common OASIS (Open Access Same-time Information System), (4) coordinated reliability and security initiatives, and (5) further development of a flow-based available transfer capability.

The Western Interconnection

Every region likes to think it is unique, but when it comes to transmission the West really is different from the East. There are many differences between the two regions, but one difference in particular jumps out with a glance at a map.

The West has huge distances between cities and states, and this presents physical challenges for the transmission of electricity.

In the West, high capacity lines stretch over long distances without significant load in between. At times, thousands of megawatts must move thousands of miles (from northern British Columbia through the Bay Area in California) during spring runoff and into the summer to the Southwest when that region's loads are the highest.

Distance alone introduces a fair degree of instability into the transmission system in the form of angular differences between generators on the sending end and generators on the receiving end of these large transfers. This inherent instability means that, under normal operating conditions, the Western grid is closer to a cascading event should the next contingency (or contingencies) occur than is the Eastern interconnection – which has multiple short lines and generators distributed everywhere. For more information about distinctions between the Eastern and Western interconnections, see Appendix B.

Appendix A: OTC exceedences, dispatcher actions

							BPA dispatcher actions				
Event	Path	Start exceedence	Exceedence duration (mm:ss)	Exceed-ence max MW over OTC	OTC reduced due to planned outage	Max BCTC Dynamic schedule to California during exceedence	A. Bypass series capacitors (# by-passed)	B. Request phase shifter operation	C. PBL generation redispatch	D. Curtail schedules	Comments
2	Paul-Allston	04-Aug-05 11:04:50	12:50	75.6	Yes (-900 MW)	0.0	Yes (4)		140 MW UC to LC	106 MW	Oxbow-Naselle 115 line section o/s, pole replacement work continued at other parts of the month
4	Keeler-Allston	04-Aug-05 13:55:50	06:00	43.2	No	0.0	Yes (4)				
6	Keeler-Allston	04-Aug-05 17:13:10	06:40	17.0	No	300.0			200 MW UC to LC		
7	Paul-Allston	05-Aug-05 09:50:10	30:00	122.1	Yes (-900 MW)	300.0	Yes (4)		300 MW UC to LC	191 MW	Oxbow-Naselle 115 line section o/s
8	Keeler-Allston	05-Aug-05 13:09:20	20:40	36.4	No	300.0	Yes (4)		140 MW UC to LC	182 MW	
9	Paul-Allston	09-Aug-05 11:57:30	08:30	51.7	Yes (-900 MW)	300.0	Yes (4)	100 MW W to E			Oxbow-Naselle 115 line section o/s
10	Paul-Allston	12-Aug-05 10:16:30	28:40	55.1	Yes (-900 MW)	300.0	Yes (4)	50 MW W to E	200 MW UC to LC	345 MW	Oxbow-Naselle 115 line section o/s
11	Paul-Allston	12-Aug-05 10:16:30	28:40	55.1	Yes (-900 MW)	300.0	Yes (4)	50 MW W to E	200 MW UC to LC	345 MW	Oxbow-Naselle 115 line section o/s
13	Paul-Allston	12-Aug-05 11:06:50	25:10	46.8	Yes (-900 MW)	100.0		100 MW W to E		110 MW	Oxbow-Naselle 115 line section o/s, BC to CISO dynamic schedule reduce from 300 to 100 MW
14	Paul-Allston	17-Aug-05 10:06:30	07:20	46.3	Yes (-700 MW)	0.0	Yes (4)	Yes	200 MW UC to LC	400 MW	Oxbow-Naselle 115 line section o/s
16	Keeler-Allston	25-Aug-05 14:04:00	16:00	30.9	Yes (-10 MW)	177.0			200 MW UC to LC	222 MW	Keeler 230/115 bank #3 o/s, install lightning arrestors 8/22-8/26. Series caps not bypassed due to North of Hanford loading.
17	Keeler-Allston	25-Aug-05 15:10:10	12:40	38.3	Yes (-10 MW)	228.0			100 MW UC to LC	72 MW	Keeler 230/115 bank #3 o/s.
18	Paul-Allston	26-Aug-05 09:55:50	17:50	73.8	Yes (-700 MW)	300.0	Yes (4)	50 MW W to E	200 MW UC to LC	356 MW	Oxbow-Naselle 115 line section o/s
19	Keeler-Allston	26-Aug-05 12:42:20	15:00	55.9	Yes (-10 MW)	300.0	Yes (4) / No (4)	100 MW W to E	Not Available	286 MW	Keeler 230/115 bank #3 o/s
20	North-of-Hanford	26-Aug-05 12:54:50	28:30	220.6	No	300.0	No (4)				
21	Keeler-Allston	26-Aug-05 13:03:00	20:10	61.3	Yes (-10 MW)	300.0				450 MW	Keeler 230/115 bank #3 o/s
22	Keeler-Allston	26-Aug-05 13:27:10	17:50	72.7	Yes (-10 MW)	300.0				300 MW	Keeler 230/115 bank #3 o/s
25	Keeler-Allston	26-Aug-05 14:02:20	10:30	36.0	Yes (-10 MW)	150.0					Keeler 230/115 bank #3 o/s
26	North-of-Hanford	26-Aug-05 14:27:10	18:00	109.0	No	150.0				300 MW	
27	North-of-Hanford	26-Aug-05 15:11:30	24:10	73.3	No	150.0			Not Available		
28	North-of-Hanford	27-Aug-05 16:26:00	09:40	73.3	No	289.0			200 MW		Scheduling limit set on COI/PDCI

Gold shaded times indicate simultaneous problems on multiple paths

Definitions: UC = Upper Columbia, LC = Lower Columbia

Notes:
1. Outages planned to minimize impact: i.e., Oxbow-Naselle 115 kV line section for pole replacement scheduled for 5 a.m. - Noon
2. Outages canceled when problems are perceived to continue - i.e., a number of outages that impact the Keeler-Allston path were canceled.
2. Column F, Red are maintenance outages for wood pole replacement
3. Column F, Turquoise are construction outages to install lightning arrestors

Appendix B: Distinctions between the Eastern and Western interconnections

If a reliability problem occurs, actions to prevent cascading must be taken quickly. That may mean a decision to drop generation or load, apply a braking resistor or break the system up into pre-engineered islands that roughly match load and generation. (Automatic actions occur in ¼ of a cycle or 1/240th of a second.) Generators are equipped with power system stabilizers. In the West, these must be on and tuned for any generator over 10 megawatts. This is more important in the West than the East. It is vital that these stabilizers are operating properly at the ends of long transmission paths.

In the Eastern interconnection, which is largely thermally limited (as opposed to stability limited), the issues are primarily about overheating transmission facilities (for instance overloading a line so that it sags too low). In most instances, operators have several minutes to respond to a thermal overload. The West's challenges are both a curse (trouble happens very fast) and a blessing (it has special automated stability controls to alleviate the problem).

The Eastern interconnection is actually quite solid. It took more than 25 contingencies or element outages before the system went into an uncontrolled cascade in August 2003. One of the problems in the East is that different NERC regions within the same interconnection have different reliability standards (for instance one region had lower voltage requirements than its neighboring regions). That causes reactive (MVAR) power[1] to flow in from neighboring regions using up line capacity, but not doing any real work. Interconnection standards need to be consistent within the interconnection but should also be tailored to the specific problems of that interconnection.

Hydro generators have a unique response to an interconnection drop in frequency (they respond quickly to make up for loss of generation anywhere in the interconnection) because of their governors. That means that limits on the intertie lines between the different parts of the West must allow for that increase in generation to flow without creating a cascading outage. Being big heavy machines with lots of mass and low RPM (compared to thermal generators), they respond more slowly but achieve a sustained response, whereas thermal units respond faster but may return quickly to their initial loading.

Commercial practices and reliability measures have grown up differently because of physical configuration differences. For instance, the Eastern interconnection uses transmission line loading relief to manage congestion. This uses contingency-based evaluation of what would cause an overload, then reduces schedules ahead of time to prevent the problem ever occurring. The West has a big loop around the interconnection and uses unscheduled flow mitigation (physical phase shifters and other measures) to physically manage "loop flow" to help with congestion.

If simulation studies indicate a contingency in the West is severe enough to cause a cascading outage, the West has special protective schemes in place that would break the system up in a controlled manner. This limits load loss, prevents equipment damage and facilitates an easier restoration. While preventing cascading is the primary goal, mitigating severity of disturbances is also important. The West has criteria about how these special protective systems are designed. They must be both reliable and secure so they are fault tolerant and super redundant. The East does not employ any

1 Reactive power: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. See glossary.

controlled separation measures (believing to do so would be a violation of NERC criteria). It has some under-frequency measures but, as of the August 2003 outage, did not employ under-voltage load shedding. However, it may be looking into these measures as a result of the outage.

The West's Reliability Management System (RMS), particularly the Phase I measures, provides the rules of the road that, if followed, would preserve reliability. Vital elements in Phase I include the following.

- Control area operator measures (CPS1, CPS2 and DCS). These ensure that loads and generation are matched (to keep frequency at 60Hz) and that the control area can recover from the loss of its largest single generator and be back in balance within 10 minutes. Operating reserves are implied here, and these measures are probably equally important in all interconnections.
- Operating within transmission path limits (OTC or Operating Transfer Capability) or restoring operation below these limits within 20 minutes (for a stability problem) or 30 minutes (for a thermal problem) following a change in system conditions that causes flows to exceed limits. This is the West's greatest reliability concern. Recalling the hydro response to loss of generation within the interconnection and the fact that the West is generally stability limited, the 20 minutes allowed to readjust the system after an event is the most vulnerable time. This is much more important in the West than in the East.
- Generators must operate in voltage control mode (meaning that if there is a disturbance and voltage declines, the generator automatically boosts its production of reactive power or MVARS and helps restore voltage to the system). This is vital in the West. The East does not require all generators to supply reactive power.
- Generators (greater than 10 megawatts) must have their power system stabilizers on and tuned when they are generating. This is also much more important in the West than the East because of the long distance, large magnitude transfers of power.

Appendix C: How others manage/relieve congestion

Roughly two-thirds of the nation's load is served by regional transmission organizations (RTO), and a vast majority of these entities use locational marginal pricing (LMP) to manage congestion. (LMP is used in MISO, PJM, New York and in New England and is proposed in California). Non-RTOs predominantly use zonal or flow-based transmission loading relief (TLR) to manage congestion (i.e., TLR is used by Entergy, MidAmerican and Duke). What these two approaches have in common is recognition of the different geographic impacts of generation and loads on flowgates. These factors serve as the foundation to manage and relieve congestion. They are described in more detail, below.

LMP allows the system operator to use generation redispatch to avoid physical congestion. It prices electricity so that it reflects the cost of generation at a generation or delivery point subject to transmission limits (each delivery point on a transmission system can have a different price).[1] The difference between LMPs at generation or delivery points is called a "congestion price"[2] and is levied on entities scheduling transmission between two points. The LMP system enables the RTO to send price signals that discourage transmission schedules across more heavily loaded paths.

Under a nodal or LMP approach, market participants do not need to obtain a physical transmission capacity reservation, or physical right, to transmit energy (see description below). So long as a customer is willing to pay the redispatch cost of its schedule, and so long as the system can physically accommodate the injections and withdrawals defined by the customer, the schedule will be accepted. This is known as an "accept all schedules" system.[3] Transmission customers can obtain financial transmission rights (FTRs) to hedge against "congestion charges." These FTRs are meant to leave owners of FTRs that schedule power in the same financial position as they would be with a physical transmission right. These financial rights may be allocated directly by translating historical point-to-point and network physical transmission rights into FTRs, distributed via auction, or distributed via a combination of the two methods. FTRs are sold in different time increments and for up to three years in advance of real time.

The other methods used (in non-RTOs) to manage congestion are based on zonal/flow-based transmission loading relief. These systems tend to employ physical transmission rights, wherein a transmission customer must have control of a megawatt of transmission in order to transmit across a congested interface. The interfaces may be defined at entry and exit points of defined zones or along defined energy paths, and transmission capacity must be scheduled in advance. These methods allow points of congestion to be identified and valued ahead of time, giving market participants an opportunity to readjust delivery schedules or the system operator time to plan congestion clear-

1 This LMP approach assumes that, in the absence of transmission limits, the least expensive electricity source would be used to serve an increment of load. However, where transmission limits restrict access to the cheapest generating source, a more expensive source must be used. The use of this more expensive generator leads to a higher LMP at the transmission-limited delivery point.

2 In this case, "congestion" does not mean that a customer cannot schedule across a path; it means that a customer may not schedule across a path without causing a need for redispatch. The cost of redispatch is paid for with congestion rent revenues.

3 "Accept all schedules" is shorthand for "accept all schedules that the system can physically accommodate and for which the customer is willing to pay redispatch costs/congestion rents."

ing actions. These clearing actions are often limited to the clearing of transmission schedules, as opposed to generation redispatch. The required physical transmission rights may be available by auction or via some form of secondary market. There are two main types of congestion management strategies under a physical transmission rights approach:

- The zonal approach defines an area or region that typically has transmission congestion and applies a physical rights congestion management strategy. Congestion zones can simplify the congestion management process by reducing the number of markets that participants would need to monitor. Power marketers have tended to prefer zones for this reason.
- The flow-based approach is similar but models congestion along defined "commercially significant flowgates" instead of between zones. This is currently the basis of BPA's long and short-term firm ATC methodologies.

Non-LMP transmission entities predominantly use zonal or flow-based transmission loading relief (TLR) in an attempt to manage congestion. (TLR is used by Entergy, MidAmerican and Duke). Transmission rights under TLR approaches can be implemented with physical or financial rights, but they have mostly been proposed using physical rights. For physical rights, under either zonal or flow-based approaches, a limited number of firm physical rights to transmission capacity are distributed via auction or through another allocation process. Only those holding physical rights can schedule transmission, usually at a pre-determined price, when transmission capacity is constrained. A secondary market can be designed to trade such physical transmission rights. Other transmission customers can submit nonfirm schedules, subject to curtailment, or rely on holders of physical transmission rights to redispatch generation to accommodate transactions.

While this latter approach can help manage congestion between zones or on a flowgate, it may not accurately assign the costs of congestion and congestion adjustments may not have the intended effect.[4]

In the Northwest there are significant concerns with LMP congestion solutions. A primary issue is that it is complex and difficult to determine nodal LMPs in a system that is dominated by interdependent[5] hydro (in this circumstance, the LMP formula does not readily yield a single solution). Secondly, translating the region's existing physical transmission rights into financial rights, as is necessary in an LMP system, is difficult to accomplish without causing unacceptable cost shifts. Furthermore, there is no ready evidence that LMP-based RTOs are able to reliably provide incentives for adequate transmission or generation construction.

This information was partially derived from a paper titled Wind Energy, Congestion Management, and Transmission Rights, Aug. 8, 2003, by Kevin Porter, et. al. (link below).

www.nationalwind.org/update/documents/transbrief01.pdf

4 To the extent that the zonal or flow-based TLRs adjust transmission schedules, they may not have the anticipated effect on generation dispatch and may not relieve congestion as effectively as intended.

5 For example, cascading hydro in which dispatch at Dam A directly affects dispatch at Dam B.

Glossary of terms

Adequacy: The ability of the power system to meet aggregate demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements and to do so without unreasonable cost impacts.

Available Transfer Capability (ATC): Measure of the electric transfer capability remaining in the transmission network over and above committed uses.

Capacity: Measured in megawatts or megavolt-amperes of generation, it is the maximum load that a transmission line (or any piece of equipment) can carry under existing service conditions.

Capacitor: A device installed to supply reactive power. A capacitor bank is a grouping of capacitors used to maintain or increase voltages on the system and to improve system efficiency by reducing inductive losses.

Cascading: The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading may result in widespread service interruption, which sometimes cannot be restrained from sequentially spreading beyond a predetermined area.

Congestion: A condition that exists when market participants seek to dispatch in a pattern that would result in power flows that cannot be physically accommodated by the system. Although the system will not normally be operated in an overloaded condition, it may be described as congested based on requested/desired schedules.

Constraint: Physical or operational limit on the transfer of electrical power via transmission facilities.

Contingency: The unexpected failure or outage of a system component or related components.

Curtailment: Reduction in the scheduled capacity or energy delivery in response to a transmission constraint.

Curtailment calculator: This is a tool used to curtail/modify previously identified schedules to reduce loadings across a flowgate. Schedules are identified based on their flow contribution to lines crossing the flowgate. These are calculated using path utilization factors (PUF), which are based on the power system's physical configuration and the impedances of its various components. The dispatcher triggers the calculator during an overload. The dispatcher enters the amount of the overload, and the program outputs those point-to-point schedules that must be curtailed pro rata to alleviate the overload.

Cutplane: See definition of flowgate.

Dispatch: Physical inclusion of a generator's output onto the transmission grid by an authorized scheduling utility.

Economic dispatch: Meeting demand with the maximum cost-effective mix of resources. The Energy Policy Act defines "economic dispatch" as the operation of generation facilities to produce energy at the lowest cost to reliably serve customers, recognizing any operational limits of generation and transmission facilities. Also see "security-constrained dispatch."

Exceedence: A circumstance when a transmission system or part of it is operating outside reliability limits established by industry standards. Sometimes called an "excursion."

Federal Energy Regulatory Commission (FERC): FERC is an independent federal agency that regulates the interstate transmission of electricity, natural gas and oil; licenses hydropower projects; ensures the reliability of high voltage interstate transmission systems; monitors and investigates energy markets; oversees environmental matters related to natural gas and hydroelectric projects; and administers accounting and financial reporting regulations and conduct of regulated companies. It uses civil penalties and other means against energy organizations and individuals who violate FERC rules in energy markets.

Firm transmission: Guaranteed access reserved for transmission service.

Flowgate: A collection of geographically close transmission lines through which electricity must flow to reach its intended destination. The total capacity limit for the flowgate is often less than the sum of the capacity limits of the individual lines because of interactions between systems. Flowgate is generally synonymous with the term "cutplane."

Grid: An electrical transmission or distribution network.

Impedance: A characteristic of an electrical circuit that determines its hindrances to the flow of electricity. The higher the impedance, the lower the current.

Intertie: An intertie is a large transmission line or lines that interconnect more than one region, allowing power to flow between regions; for example, to and from the Northwest and other geographic networks such as Canada and the Southwest.

Nomogram: Graph for displaying data (i.e. transfer capability) based on certain variable values such as temperatures, loads, generation and line conditions.

Nonfirm transmission: Transmission service reserved or scheduled on an as available basis. It can be interrupted.

North American Electric Reliability Council (NERC): NERC is a nonprofit corporation made up of members from regional reliability councils representing all segments of the electricity industry. NERC membership accounts for virtually all electricity supplied and used in the United States, Canada and a portion of Baja California Norte, Mexico. NERC's goal is to ensure that the bulk electricity system in North America is reliable, adequate and secure. It is expected to become the new electric reliability organization subject to FERC oversight established in the Energy Policy Act of 2005.

Open Access Transmission Tariff (OATT): Tariff for use of high voltage transmission lines required by the Federal Energy Regulatory Commission's Order 888. Designed to facilitate open, nondiscriminatory access to all transmission facilities by all power providers.

Operating transfer capability (OTC): The threshold up to which the transmission system can be operated safely and reliability. It is arrived at through complex system studies. The Western Electricity Coordinating Council assesses penalties on transmission owners or flowgate operators when a transmission flowgate OTC is exceeded longer than 20 or 30 minutes (the timing depends on whether a stability-limited path or a thermally limited path is involved).

Phase shifters: These are specially designed transformers that are used to control the flow of power on parallel transmission paths.

Reactive power: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. Reactive devices also must supply the reactive losses on transmission lines. Reactive power is provided by generators, synchronous condensers or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kVAR) or megavars (MVAR). VAR stands for volt-amperes reactive. Examples of reactive loads include motors and transformers. These types of loads, when connected to an AC voltage source, will draw current, but because the current is 90 degrees out of phase with the applied voltage, they may actually consume no real power in the ideal sense.

Redispatch: Management of generation patterns to overcome flowgate congestion or outage problems.

Remedial Action Scheme: Such schemes employ high-speed electronic controls that allow the transmission system to quickly analyze and respond to problems by automatically dropping generators or load, applying a large braking resister to slow accelerating generators and other measures. RAS arming is monitored 24 hours a day.

Security-constrained dispatch: FERC has recognized that a dispatch pattern of generating facilities that respects transmission operational limits or “constraints” is a “security constrained” dispatch. Under FERC guidelines, security refers to the secure or reliable operation of the grid.

Series capacitors: An installation of capacitors with fuses and associated equipment in a series with a line. Generally located near the center of a line, but not always. Used to increase the capability of interconnections and in some cases achieve the most advantageous and economical division of loading between lines operating in parallel.

Stability-limited path: Flowgate OTC is defined by voltage stability or transient stability limits. A transmission provider has a maximum of 20 minutes to bring flows below operating transfer capability limits on a stability-limted path when OTC is exceeded.

System reliability: Measure of an electric system’s ability to deliver uninterrupted service at the proper voltage and frequency.

Thermally limted path: Flowgate OTC is defined by equipment limitations (e.g., transformers, conductors, breakers). A transmission provider has a maximum of 30 minutes to bring flows below operating transfer capability limits on a thermally limted path when OTC is exceeded.

Transfer: Moving electricity from one utility system to another via transmission lines.

Western Electricity Coordinating Council (WECC): WECC is the largest and most diverse of the regional councils that make up NERC. WECC’s service territory includes all or portions of the 14 Western states, two Canadian provinces, and the northern portion of Baja California, Mexico. WECC and the other regional reliability councils were formed to address concerns regarding reliability of the interconnected bulk power systems and the need to foster reliability through a formal organization.