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Reliability Standards for the Northwest Power System

Abstract

For lack of a better measure, the electric utility industry generally references 95-percent reliability as a "standard" for the Northwest power system, but it is a goal and not an official regulation, requirement or code. As the nation's electricity industry becomes increasingly competitive, and as our nation becomes increasingly dependent on technology that requires highly reliable electric power, the issue of a regional or national reliability standard looms large. What is an acceptable standard? How would it be created, and what would it address? Should there be one standard or several? Occasional power outages are an inconvenience for some and a disaster for others. Perhaps there is no need for a "standard," as consumers who need highly reliable power can pay for that privilege by purchasing their own backup generators, and those for whom reliability is less critical might be willing to accept whatever reliability their power supplier provides -- and at a lower cost. This paper explores past efforts to define and assess reliability, and recommends next steps for developing a standard or standards. Separate standards for generation planning, operation and transmission probably are warranted. For operations, a deterministic standard might be crafted around minimum reserve requirements. For generation planning purposes, a probabilistic standard (one that incorporates the frequency, duration and magnitude of customer interruptions) could serve. For transmission, it seems appropriate that an independent Regional Transmission Operator (RTO) would establish a standard, with attention to reducing congestion and rewarding distributed generation when it relieves stress on the system.

Background

Historically the Northwest has enjoyed abundant and relatively cheap electrical power, primarily from the large hydroelectric facilities built on the Columbia River. This inexpensive supply of electricity lured aluminum companies and other industries to the Northwest, prompting population and economic growth. Over time, continuing increases in demand for electricity coupled with environmental restrictions placed on the hydroelectric system and limited investment in new resources have made the supply much tighter.

In 2000, the Council evaluated the reliability of the region's power system.[1] Results of the Council's assessment indicated that reliability was below general expectations. The movement toward a deregulated industry could worsen the situation if the market does not provide adequate

[1] "Northwest Power Supply Adequacy/Reliability Study Phase 1 Report," Council Document 200-4, March 6, 2000.

economic incentives for new resource development.[2] This year's drought combined with the dysfunctional market design in California has further exposed the power system's unreliability.

During the summer of 2001, emergency actions were taken to keep lights on in the Northwest, but those actions were only a temporary fix. Requests for voluntary cutbacks, buyback of customer demand, emergency short-term generating resources and curtailment of fish and wildlife operations all contributed to avoiding outages and leaving the reservoir system with enough water to minimize, but not eliminate, problems for the upcoming winter.

The Northwest Power Act[3] instructs the Council to plan for the future of the power system, and to inform citizens and involve them in the planning process. One of the goals of the Northwest Power Act is to assure the region of an adequate, efficient, economical and reliable power supply. Based on this mandate, the Council is initiating a regional discussion regarding reliability. This paper is intended to provide background information for this discussion.

Defining the Power System

A power system can be very complex, integrating many different types of generating resources to provide electricity to a number of customers with varying requirements. Each individual component has its own characteristics, including its dependability or reliability. One can imagine the difficulty in trying to evaluate the reliability of such a complex system as a whole. To simplify the task somewhat, power systems are generally broken down into three major components; the generation system, the bulk transmission system and the distribution network. The generation system includes all resources that produce electricity, including oil and gas-fired turbines, coal and nuclear plants, hydroelectric dams, windmills and all other generators. The bulk transmission system includes high voltage transmission lines that connect generators to distribution networks. The distribution networks, made up of all the lower voltage lines, deliver electricity to individual customers.[4]

To our knowledge, no one has attempted to evaluate the reliability of a power system as a whole. Generally, individual utilities assess the reliability of their own distribution networks. Federal agencies monitor the operation and reliability of the bulk transmission system and regional agencies, such as the Northwest Power Planning Council, assess the adequacy of the generation system (including load management tools). In gross numbers, the distribution component of a power system is responsible for about 85 percent of interruptions. The bulk transmission and generation components are responsible for about 5 percent and 10 percent of interruptions, respectively.[5] This paper focuses on methods to assess the reliability of the generation component of the power system.

Organizations Involved

Many organizations play a role in the planning and operation of the Northwest power system, ranging from the generation of electricity through the bulk transmission system to the lower voltage

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[2] It should be noted that conservation and renewable resources are a part of "new resource" development.
[3] 16 USC 835b (d) and (g).
[4] Some power systems actually contain a fourth component that provides active control to some part of the demand. Radio controlled water heater shutoff circuits are an example of such devices. Total system reliability can be increased with such demand-side management tools.
[5] These values are approximate. Reference to the study was not discovered in time to provide detailed values or their source.

lines that form utility distribution networks. Each organization has its own responsibilities and authority. Each organization also defines reliability in its own way. There is no universal standard for reliability. In practice, each component of the system, the generation, the bulk transmission and the distribution network, may be subject to different sets of standards. Some of the major organizations involved in power system reliability are identified below.

The **North American Electric Reliability Council** (NERC) was formed in 1968 as a voluntary organization to develop and implement reliability standards for the bulk transmission system in the United States. Currently, NERC does not have the authority to enforce its standards but is working with its members to incorporate a mechanism of enforcement by way of voluntary contracts between its regional councils and their members. To ensure statutory authority to enforce compliance, however, federal legislation is needed. NERC is in the process of transforming itself into the North American Electric Reliability Organization (NAERO) and is working toward passage of enforcement legislation.

Sponsored by the U.S. Department of Energy and the California Energy Commission, the **Consortium for Electric Reliability Technology Solutions** (CERTS) was formed in 1999 to research and develop new methods to protect and enhance the reliability of the U.S. electric power system during the transition to a competitive market structure. Its vision is four fold:

1. To transform the electricity grid into an intelligent network that can automatically respond to emerging problems,
2. To integrate distributed generation and communication technologies to support reliability needs,
3. To enhance reliability management through market mechanisms, and
4. To empower customers to manage their energy use in response to real-time market prices.

The **Committee on Regional Electric Power Cooperation** (CREPC) is a joint working committee of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners. The Western Interstate Energy Board is an organization of 12 western states and three western Canadian provinces. The governor of each state appoints a member to the Board. The legal basis for the Board is the Western Interstate Nuclear Compact (Public Law 91-461). The Compact provides for the President of the United States to appoint an ex-officio member to the Board. The CREPC, which consists of public utility commissions, energy agencies (including the Northwest Power Planning Council) and facility siting agencies. Its goal is to improve the efficiency of the western electric power system.

The **Western Systems Coordinating Council** (WSCC) was organized in 1967 and provides the coordination required to plan and operate the bulk transmission grid in the Western United States and Canada. WSCC is committed to being the regional forum for promoting electric system reliability through the development of reliability criteria, monitoring compliance, facilitating a planning process and coordinating system operation through security centers. The **Northwest Power Pool** (NWPP), an organization created to implement the operation under the Pacific Northwest Coordination Agreement, monitors and relays information regarding the status of the power system to the WSCC.

The **Federal Energy Regulatory Commission** (FERC) is an independent regulatory agency within the Department of Energy. Created in 1977, FERC replaced the Federal Power Commission. Along with its other duties, FERC regulates the transmission and wholesale sales of electricity and provides licenses for municipal and state hydroelectric facilities.

Public Utility Commissions (PUCs) in each state regulate utility industries to ensure that customers receive safe reliable services at reasonable rates. The commissions may require each utility to perform a least cost plan that covers the rate period. In this way the commission can determine whether the planned system will be adequate and whether the rates are reasonable. It is not clear what role the commissions will have in a deregulated industry.

The **Northwest Power Planning Council** (Council) was created on April 28, 1981 in accordance with the Pacific Northwest Electric Power Planning and Conservation Act. The Council was authorized by Congress to encourage conservation and the development of renewable resources and to assure an adequate, efficient, economical and reliable power supply for the Northwest. Since 1981 the Council has produced a series of power plans for the Northwest, focusing on cost-effective generation and conservation. Bulk transmission and distribution system analysis has not been emphasized in previous power plans.

The **Bonneville Power Administration** (BPA) and other **electric utilities** monitor and control their own systems but must coordinate their actions with others to ensure system wide reliability. The Northwest is divided into 15 control areas. Each control area has the responsibility to report resource and demand information to the WSCC. When potential problems are identified, all the control areas are notified and participate in corrective actions.

Defining Reliability

In general terms, reliability is a measure of how well a system performs its expected function. Another system characteristic that is closely associated with reliability is adequacy. A system is adequate if it has sufficient resources to perform its function. A system can be adequate but unreliable. However, if a system is inadequate, then by most definitions it is also unreliable.

For electrical power systems, these two terms can be defined more specifically. The North American Electric Reliability Council defines power system reliability to be:

> [t]he degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system -- adequacy and security.
> **Adequacy** - The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
> **Security** - The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.[6]

The NERC definitions of adequacy and security apply to both the generation and transmission systems. Both systems must be able to continue operation after a sudden disturbance -- either a loss of a major transmission line or a major generator. A power system is unreliable if either

[6] "Glossary of Terms," North American Electric Reliability Council, Glossary of Terms Task Force, August 1996

its transmission or generation systems are inadequate. Unfortunately, analyzing the composite reliability of both systems is very difficult.[7] Because of this difficulty and because in practice the reliability of each system is usually measured separately, the focus of this paper will be on the generation system. However, the Northwest Power Planning Council is also participating in discussions regarding the bulk transmission system and is in favor of establishing a Regional Transmission Operator that will have some control over transmission reliability.

The Northwest Power Planning Council has defined the terms "reliable" and "adequate" in a slightly different way for the generation system. As described in Appendix C of the Council's 1994 Fish and Wildlife Program, an adequate power supply "is one where power resources are either currently available or can be developed in time to meet forecast demands with an adequate reserve margin." This definition introduces a related term, "reserve margin," which will be discussed later. The appendix goes on to say that reliable "means the short-term ability to meet load. It is distinguished from 'adequate' by the time dimension." In other words, given the configuration of the system at the time it is called upon to provide power, can it deliver within acceptable standards?

When the Council discusses reliability, it means the short-term ability of the existing and planned generation system to deliver electricity when needed, including unusually cold periods or times when generators are out of service. In the Council's March 2000 analysis, it concluded that the generation system was "inadequate" meaning that more resources were needed in order to lower the risk of blackouts to an acceptable level. In that sense, the Council concluded that the power system was also unreliable.

Reserve Requirements

To help ensure a higher likelihood of uninterrupted service, all utilities are required to maintain a certain level of reserve margin. A reserve margin is simply resource capability in excess of the expected peak demand. Reserve resources are called into service when unexpected outages occur. If reserve resources are used more often than expected, it implies that the power system is inadequate and therefore unreliable.

The WSCC requires reserves equal to 5 percent of load supplied by hydroelectric resources plus 7 percent of load supplied by thermal generation, with spinning reserves[8] not less than one half of the total operating reserve. WSCC is currently reviewing this policy and may change these requirements. Increasing the reserve margin provides a more reliable power system but at a higher cost. Decreasing the reserve margin saves money but could mean higher likelihood of curtailment.

Capacity and Energy

For a power system, planners must also distinguish between capacity and energy shortfalls. The capacity of the system is its ability to deliver power to meet instantaneous demand requirements. The power system must also be able to deliver, on a sustained basis, the average energy requirements of the region. Another way to look at the difference between capacity and energy (especially for a predominantly hydro system) is to consider fuel as opposed to machines. Does the system have enough machines to meet the peak demand? Does the system have enough water and fuel to run the

[7] The Electric Power Research Institute (EPRI) has developed an analytical method (CREAM software package) to assess the composite generation and transmission reliability. More information is available at www.epri.com.

[8] Spinning reserves are units connected to the grid, synchronized and ready to take load or are units that are available with quick start capability.

machines when needed? Curtailment of service can occur if the system has insufficient machines or fuel or both.

Most power systems in the world plan for capacity needs -- ensuring that enough resources are in place to serve the peak demand. Their ability to meet load is limited by their peak generating capacity, rather than the fuel available for their generating facilities. For these systems, the total generating capability usually far exceeds the average energy requirements.

For systems that incorporate a large share of hydroelectric generation, however, planning is usually done on an energy basis. This is because reservoirs behind the dams generally cannot hold enough water to run each project at full capacity all year long. These systems are considered energy limited and capacity surplus.[9] For the Northwest region, the peaking capacity is about 42,000 megawatts and the average annual energy production is about 21,000 average megawatts.

In a capacity-limited system, no additional amount of fuel will increase service to customers. In an energy-limited hydroelectric system, no additional number of turbines will help. (Although adding other non-hydro generators obviously would improve the situation). To make matters more complicated, quite often the operation of resources is limited by constraints designed to protect air or water quality or to enhance fish survival.

How do capacity and energy relate to reliability and adequacy? A system is adequate if it has enough resources and fuel to meet both the peak demand and the annual average energy requirement. A system is reliable if it can deliver power when called upon to do so within acceptable standards, taking into account scheduled and reasonably expected unscheduled outages of system elements. (Systems are generally designed to withstand the loss of a major transmission line or the largest generating resource).

Up to this point, we have defined reliability in qualitative terms. In order to measure reliability, a quantitative definition must be developed. In the following section, several approaches are explored.

Measuring Reliability

There is no single index that is universally used to express the reliability of a power system. Reliability indices can be broadly categorized as either deterministic or probabilistic. Deterministic indices are calculated with known system parameters and provide a static look at the system. Their advantage is that they can be easily measured; their deficiency is that they are a poor representation of system reliability because they do not take unforeseen events into account very well. Operating reserve margin is an example of a deterministic index.

Probabilistic measures incorporate the dynamic nature of a power system. Statistical methods are used to account for future uncertainties in system components. These indices provide a much better indication of reliability but are more difficult and take more time to calculate. Probabilistic reliability indices usually include the frequency, duration and magnitude of customer interruptions. Using these three parameters, various indices can be constructed.

[9] A power system can be both energy and capacity deficit as is the case for the Northwest today.

Reliability assessments are crucial for planning system expansion and other long-term programs (such as demand-side management). They are also critical to system operators in making decisions for short-term and daily operations. Long-term planners have more time to assess the reliability of potential future systems and can therefore use probabilistic indices. System operators on the other hand, require a much quicker assessment of system reliability and are more likely to use deterministic indices. The reserve margin is a good candidate for use by system operators. For system planners, such as the Council, probabilistic measures are a better choice. A discussion of probabilistic indices follows.

Probability - (Frequency and Duration)

The Loss of Load Expectation (LOLE) is a reliability index that identifies the likelihood that generation will be insufficient to meet peak demand during a part or all of a year. NERC defines this index as:

> The expected number of days in the year when the daily peak demand exceeds the available generating capacity. It is obtained by calculating the probability of daily peak demand exceeding the available capacity for each day and adding these probabilities for all the days in the year. The index is referred to as Hourly Loss-of-Load-Expectation if hourly demands are used in the calculations instead of daily peak demands. LOLE also is commonly referred to as Loss-of-Load-Probability (LOLP).

Using a Monte Carlo simulation model,[10] a large number of potential futures can be simulated with each element of the system varying randomly based on its known operational characteristics. From the many potential futures, it is easily assessed how many days demand was not satisfied (or reserves were not met). The LOLP is then just the number of days when generation was insufficient divided by the total number of days simulated. If the LOLP is 5 percent, that means that demand was not satisfied in 5 percent of the total number of simulated days.

It should be noted that the LOLP can measure hourly, daily, weekly, monthly or seasonal reliability. For example, instead of daily LOLP, seasonal LOLP is easily calculated if that is a more important parameter for decision-making. The Council recently analyzed the winter-season LOLP for the Northwest power system.[11] The study concluded that (with some additional storage in Canadian reservoirs) the seasonal LOLP was about 12 percent for the period between December 2001 and March 2002. This means that in 12 out of every 100 winter-seasons analyzed, at least one insufficiency occurred. It is also likely that multiple insufficiencies occurred in some winters. However, the LOLP does not differentiate between single and multiple curtailment seasons.

Magnitude

While the LOLP is an important index in terms of identifying whether a generation system is reliable, it is an incomplete picture. It does not, for example, give us any indication of the size of the problem. The average magnitude of insufficiency is important in the process of planning for corrective measures. This reliability index, namely the Expected Unserved Energy, is defined by NERC below.

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[10] The term "Monte Carlo" refers to a probabilistic approach to analysis.

[11] A summary of the results can be found at www.nwcouncil.org/energy/powersupply/pwr_spply_outlook_0501-0402.pdf.

"The expected amount of energy curtailment per year due to demand exceeding available capacity. It is usually expressed in megawatt-hours."

As an example of how such indices may be used for a **distribution system**, the following is quoted from the Draft Electricity System Study ESSB 6560, Section 8-Electric Service Reliability.[12]

> There is no federal or industry standard for these indices. A committee of the Institute of Electrical and Electronic Engineers Inc. (IEEE) has proposed a reliability standard. Specifically, two of the proposed indices were identified by the utilities as useful performance measures. The System Average Interruption Frequency Index or SAIFI, is the average number of interruptions experienced by customers during the year. The System Average Interruption Duration Index or SAIDI, is the average number of minutes of interruption experienced by customers during the year. The proposed standard only counts 'sustained interruptions,' which are defined as those lasting five minutes and longer. The SAIFI and SAIDI measure averages for the utility's distribution system, so it is important to remember that they reveal nothing about extreme values that may be included in the average.

Putting It All Together

A more straightforward method of portraying reliability is simply to evaluate the expected frequency, duration and magnitude of interruptions for a given power system. Given this data, the LOLP and expected unserved energy can easily be calculated. In addition, statistical information regarding the uncertainty in the expected values and extreme conditions is very valuable. For example, displaying the distribution of the duration of interruptions gives us an idea of how long the problem lasts. Are the majority of interruptions short or long? The same can be done with the magnitude. Are we dealing with large interruptions or small ones?

A reliability standard can be developed that includes all of these indices. For example, a hypothetical standard would be that a system experience no more than one interruption greater than 1,200 megawatts lasting longer than one day over a 20-year period. In the Council's assessment of reliability, it attempted to incorporate the magnitude into its calculation of the LOLP for the winter of 2001-02. The 12 percent LOLP counted winter seasons when the average seasonal curtailment was greater than 10 megawatts. Because the winter season analyzed was 120 days, the 10 megawatt-season value translates into one 1,200 megawatt-day outage or two 600 megawatt-day outages or one 40 megawatt-month outage, etc. If we were to implement the hypothetical standard mentioned in the second sentence of this paragraph, we would revise the Council's assessment to include only outages that were greater than 1,200 megawatts lasting longer than one day.

This type of standard may be appropriate for system planners but would do little good for system operators. First of all, evaluating this parameter generally requires a lengthy analysis, certainly not doable on a daily or hourly basis. Secondly, it does not offer operators a good indication of what actions should be taken to alleviate the problem. A more useful standard for operators might be a lower bound on voltage drops or a range of frequency deviations. As soon as these limits are violated, compensatory actions can be taken. Another example is the use of reserve margins as a surrogate for reliability standards. They are easy to establish and monitor but they are

[12] This study was initiated by the Washington State Office of Trade and Development in conjunction with the Washington State Utilities and Transportation Commission.

arguably conservative and could be costly to maintain. Whatever standard is developed for system operators, it must be quickly accessible to those who control the flow of power.

If separate reliability standards are developed for planners and operators, how are they related? Operation standards are intended to keep the current system up and running (secure). If operation standards are violated by an inordinate amount, it means that the system is likely inadequate and planners have not done their job correctly or their plans have not been implemented or unexpected changes have occurred. Planning standards are intended to provide adequate systems for operators. Planning actions generally require years to implement and are often modified due to unanticipated changes in demand or policies (such as environmental constraints). Operation standards are most often defined under the assumption that the system is adequate.

Reliability and the Market

Historically, reliability standards (whenever they have been established) have been static and universal, that is, constant for all customers within a particular system. New resource (and demand-side) technology and increasing costs force us to examine current standards. In the future, it is more likely that reliability standards will be dynamic in nature and perhaps not even universal. It may be possible for different customers to have (and pay for) different levels of reliability. Even today, certain industries (such as hospitals) buy reserve generators to use in the event of interruption. In a sense, these organizations are paying a premium for higher-than-standard reliability.

The transition from a regulated electricity industry to a free market will further complicate the issue of reliability or make it irrelevant. In a true market condition, where each consumer sees real electricity prices and has real choices among the providers, universal reliability standards do not apply. In this situation, each customer would "pay" for whatever level of reliability he can afford or wants. In conceptual terms, a "basic" standard would be associated with the general market, and individual consumers who wish to have more or less reliable service could take appropriate actions.

In fact, we do not have a true market condition. It is not even clear whether we can ever achieve a true market situation. We find ourselves in a transition, with some regions more deregulated than others. These regions may even overlap, with some utilities providing service to areas that are deregulated and others that are not. Under the current situation, the issue of reliability standards becomes more complicated. Even if a standard can be developed, how will that standard be enforced? One of the key elements of reliability in a free market is response time. It is yet to be determined whether the "market" will respond quickly enough to provide some of the reliability functions that regulated utilities have in the past. If the market cannot provide the incentives then who can and will?

Resource development will be based on economic projections. A developer will not be willing to invest money unless there is at least a good chance of making a profit. Also, the scope of decisions may be shorter term than in the past. Making a profit in the next year or two seems to be more important than betting on making money in the longer term.

In the shorter term, providing resources to meet unexpected peaking demands will be difficult, particularly in a hydro-based system. A developer is unlikely to invest in a long-term resource that will only operate occasionally, say for a month or two every four years. This is not uncommon for a system like ours in the Northwest, with the bulk of the generation coming from hydroelectric facilities. Also, even if a developer would be willing to take the risk, assuming that the extremely high prices over the short period of need would compensate for the period of inoperation, government could step in and cap prices, possibly reducing the incentive to build.

Where Do We Go From Here?

Defining the terms "reliable" and "adequate" is a much easier task than establishing and enforcing standards, especially in an industry transitioning from a regulated environment to a free market. No universal reliability standard exists for a power system as a whole. NERC's **bulk transmission** standards are close to universal but are currently voluntary. For **distribution networks**, an unscientific sampling indicates that most utilities use a one-day in ten-year standard. This translates into a one-in-ten year event if multiple outages per year are lumped together. Standards for **generation systems** are more obscure. For hydro-based systems, a 5 percent LOLP, which translates into a one-in-twenty year event, seems to be a generally accepted value. **System operators** rely on operating reserves as a surrogate for a true reliability index.

First of all we should recognize that operators and planners should appropriately have different standards. Secondly, standards for transmission will differ from those for generation, at least until more progress is made in composite system analysis.

For the transmission system, the Council has supported the establishment of an independent Regional Transmission Operator (RTO), in part because it believes such an entity should be in a better position to address the issues, such as constrained transmission paths, that affect system reliability. Mandatory security standards must be established, and the RTO should have authority to take action in emergencies.

For the generation system, minimum operating reserve requirements should be re-examined and enforced more vigorously by system operators. Generation planners should develop a useable probabilistic reliability index that will lead to adequate and reliable future systems. New resources should be sited to minimize transmission stress (or the need to build more transmission) if it is more cost effective than reinforcing the transmission system. In fact, distributed generation should be considered and given some credit for saving transmission costs. Probably most important of all, demand-side management efforts should be explored more rigorously.

If the current power system is not reliable, fixing the problem may require more generation or demand management or expansion of the transmission system -- efforts that can take a long time to implement. In such cases, short-term mitigating actions must be taken. Those actions may include voluntary or contracted reduction in demand, adding high-operating-cost temporary resources or increasing imports from out-of-region utilities. If the emergency is severe, air quality and other environmental constraints may be temporarily lifted. This is the situation that the Northwest found itself in this past summer. None of these short-term fixes are desirable. With the proper reliability indices and enforcement mechanisms, the region should be able to avoid these situations in the future.

Legislative Efforts

Congressman Joe Barton, Chairman of the House Energy and Commerce Committee's Subcommittee on Energy and Air Quality, has released a draft electricity restructuring bill for informal review. In that draft, he includes a section on electricity reliability.

This section would add a new section 216 to the Federal Power Act providing for FERC certification of an electric reliability organization to develop enforceable reliability standards. It provides for FERC jurisdiction within the United States over such a reliability organization and users and owners of the bulk power system.

The provision authorizes FERC to approve a proposed reliability standard if it determines the standard (1) is necessary or appropriate to protect the reliability of the bulk power system, (2) is just, reasonable, not unduly discriminatory or preferential, (3) is in the public interest, and (4) does not impose a burden on the transmission of electricity in interstate commerce and the sale of wholesale electricity that is necessary or appropriate to protect the reliability of the bulk power system. In addition, this section authorizes the electric reliability organization to impose a penalty on the user or owner or operator of the bulk power system if it finds, after notice and an opportunity for a hearing, that the user or owner or operator violated a reliability standard.

This provision is based on, though not identical to, the proposal to transform NERC to NAERO and give it authority to enforce reliability standards. But because this provision does not endorse NERC as the reliability organization, there could be a significant national debate over this section.

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