# *Maintaining Reliability in a Competitive U.S. Electricity Industry*

## Final Report of the Task Force on Electric System Reliability

**September 29, 1998**

**Secretary of Energy Advisory Board**
U.S. Department of Energy

# Secretary of Energy Advisory Board
# Task Force on
# Electric System Reliability

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# Preface

The Secretary of Energy Advisory Board Task Force on Electric System Reliability was convened in January 1997 to provide advice to the Department of Energy on the critical institutional, technical, and policy issues that need to be addressed in order to maintain the reliability of the bulk-power electric system in the context of a more competitive industry. The findings and recommendations contained in this report pertain to all segments of the electric industry. The Department must continue to work closely with the U.S. Congress, the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Council (NERC), system operators, and market participants to ensure continued electric reliability. Each has an important role to play in carrying out the Task Force's recommendations.

There is a sense of urgency throughout this report. Driven by the expectation of billions of dollars in annual savings to the Nation's economy, the electricity industry is in a transition from a highly regulated industry dominated by monopoly utilities to an industry that will rely, in large part, upon competitive commercial markets at both the wholesale and retail levels. The industry is unbundling, and the old institutions for reliability are no longer sufficient. We are already in the middle of our journey toward a restructured electricity industry. However, the new policies and institutions needed to assure electric reliability are not yet in place. Until such policies and institutions are in place, substantial parts of North America will be exposed to unacceptable risk.

We are heartened by the work already underway. The early recommendations of this Task Force have been well received. The Administration has proposed legislation that would provide the federal oversight necessary to make reliability standards mandatory. The NERC has begun to reinvent itself to respond to the changing needs of the industry. In addition, the FERC has undertaken several reliability initiatives. However, much more is needed. The Congress, for example, urgently needs to clarify the FERC's authority

# Executive Summary

## Background

The U.S. electric industry is changing and, indeed, has *already* changed in several respects. Wholesale electric markets are increasingly competitive under open-access transmission tariffs. Eighteen States, containing almost one-half of the Nation's population, have decided to permit retail consumers to choose their suppliers, and nearly all of the remaining States are studying retail competition.[1] Some electric utilities are selling their generating assets. Energy companies are merging and establishing innovative joint ventures. New companies are entering competitive markets. And new institutions, including independent system operators and power exchanges, are forming.

These trends point to a future in which market forces will increasingly determine when, where, and what types of generation sources will be built and which energy trades will be transacted. It is also apparent that the Nation's transmission grid will be used by many more (and more diverse) entities for a larger quantity and variety of transactions. With these changes comes a critical challenge: Will consumers of electricity be able to count on traditional levels of grid reliability?

The Secretary of Energy Advisory Board's Task Force on Electric System Reliability was formed to address this question. The Task Force had its genesis in the major Western power outages during the summer of 1996. In response to those outages, the U.S. Department of Energy (DOE) created the Task Force to "advise on critical institutional, technical, and policy issues that need to be

[1]Source: U.S. Energy Information Administration as of September 1, 1998. Details are available at the EIA Web site: www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.

over an electric industry self-regulating reliability organization and expand the FERC's jurisdiction for reliability over the bulk-power system.

This report contains twenty-eight recommendations. They were developed by a diverse group representing all major segments of the electric industry, including representatives from public and private utilities, independent power suppliers, power marketers, customers, regulators, environmentalists, and academics. The Task Force on Electric System Reliability firmly believes that these recommendations are balanced, nondiscriminatory, and achievable.

Staff from the Office of the Secretary of Energy Advisory Board, the Office of Economic, Electricity, and Natural Gas Analysis, and the Department's laboratories have provided invaluable support to the Task Force during its deliberations and their contributions are very much appreciated.

*The Honorable Philip Sharp*

addressed in order to maintain bulk electric system reliability in the context of a more competitive industry."

In December 1996, the Secretary of Energy appointed the members of this Task Force, which then held its first meeting in January 1997. The 24 members of the Task Force represent all major elements of the electricity industry, including private and public suppliers, power marketers, customers, regulators, environmentalists, and academics. The Task Force members are listed on page ii. The Task Force met at 2-month intervals between January 1997 and September 1998. As deliberations proceeded, the Task Force prepared and issued formally approved interim work products. Part II of this Final Report includes these technical papers.

## Task Force Findings

The Task Force believes that restructuring the electric industry offers economic benefits to the Nation. Transmission-grid reliability and an open, competitive market can be compatible. Although the changes being brought about by restructuring are complex, the reliability of the bulk-power system need not be compromised — provided appropriate steps are taken.

**These steps must be taken soon. Indeed, the Task Force believes that the primary challenges to bulk-power system reliability are presented by the transition itself, rather than by the end state of competition. Failure to act will leave substantial parts of North America at unacceptable risk.**

The traditional reliability institutions and processes that have served the Nation well in the past need to be modified to ensure that reliability is maintained in a competitively neutral fashion, without favoring one or another set of market participants, as portions of the Nation's electricity markets shift to open competition. Specifically, the Task Force reached consensus on several key points concerning the change that is occurring in the electricity industry and its effect on reliability:

- The viability and vigor of commercial markets must not be unnecessarily restricted. The market forces now being introduced depend on fair and open access to the transmission grid.

- There is uncertainty regarding statutory and regulatory authority over reliability management. This is being exacerbated by the unbundling of vertically integrated utility functions.

- Commercial markets should develop economic practices consistent with the ingenuity and mutual interest of the participants. Grid reliability must be maintained through technically and economically justified standards and practices.

- Reliability standards must be clear, transparent, nondiscriminatory, enforceable, and enforced. Compliance must be mandatory for *all* entities using the bulk-power system.

- Regulatory oversight is necessary to ensure compliance with reliability policies and standards and to resolve disputes.

- Historically, the North American Electric Reliability Council (NERC), the regional reliability councils, and individual utilities have managed reliability through a system of peer-reviewed standards coupled with voluntary cooperation and adherence to reliability rules. In that system, costs associated with maintaining reliability could be recovered through rates, and peer pressure and reciprocal treatment of costs were generally sufficient to keep utilities in compliance. The system is clearly unsustainable in the increasingly decentralized and competitive U.S. electricity industry.

- It is reasonable and practical to build on the experience and reliability standards developed by NERC and the regional reliability councils over the past three decades. However, these standards as well as the reliability councils' systems of governance must be modified to accommodate the complexities of competitive markets.

- Grid reliability depends heavily on system operators who monitor and control the transmission grid in real time. To ensure competitive use of the grid, system operators must be independent from and have no commercial interests in electricity markets.

- Independent system operators (ISOs) are significant institutions to ensure both electric system reliability and competitive generation markets.

- Because bulk-power systems are regional in nature, they can and should be operated more reliably and efficiently when coordinated over large geographic areas.

- The reasonable and necessary costs for maintaining reliability should be fully recoverable and equitably distributed among electricity users.

- For the time being (at least) and for the long term (at most), responsibility for grid construction, operation, and maintenance is expected to be a monopoly with its use and cost overseen by government regulators and operated in many parts of the country by independent system operators. ISOs should conduct planning and implementation for transmission enhancement, much as vertically integrated utilities do today, and provide congestion-based signals so that markets might resolve congestion-related problems through market forces.

- At present, there is no national consensus on the appropriate way to price transmission services in order to provide optimal incentives for both investment in transmission facilities and the demand for transmission services. Given the lack of consensus, it is appropriate and desirable that a variety of approaches are being tested around the country.

- Energy generation will be increasingly market based. Generation investment decisions will be made by commercial entities assuming the risks associated with their decisions. But the viability of a generator depends in part on the market it is selling into. If that market is influenced by congestion, the investor will want information concerning how long that congestion is likely to last. Similarly, decisions concerning congestion-relief investments should be influenced by expectations concerning future generator locations.

- Transmission-grid reliability is a North American issue; the reliability relationships with Canada and Mexico must be preserved. Consultation with Canadian and Mexican governments is important for ensuring reliability in the interconnected North American bulk-power market.

- State governments have historically had authority over the siting of transmission facilities and have provided the right of eminent domain to utilities where necessary. Frequently, State processes for review include comprehensive evaluations of alternatives to utility-proposed solutions for relieving transmission constraints. Electric systems are becoming more regional in character. The reliability benefits of transmission enhancements can benefit many States, not just those where the facilities are sited.

- Fair and proper allocation of costs among users will lessen the likelihood of States denying permission to construct new transmission facilities to accommodate firm transmission service on the basis that retail customers would be economically harmed (that is, siting/certification decisions would be made independent of economic issues).

- The challenge of maintaining transmission reliability is to better understand and control disturbances that may originate in an isolated, local event but whose effects may almost instantaneously propagate throughout the system as a whole. Fortunately, a variety of new technologies are becoming available that can help to ensure transmission reliability while also enabling the grid to handle increased demand on transmission facilities that could result from industry restructuring.

- The transition to a competitive market will lead to unbundling of energy services such that acquisition of energy will be separate from voltage support, spinning reserves, standby generation, congestion management, and other ancillary services. This creates the opportunity to develop and demonstrate distributed technologies for the specific purpose of reliability management such as distributed generation, energy storage systems, voltage controllers, local network management system protection, and other technologies.

- For the bulk-power system to be operated reliably even in areas where such new systems are not being built from scratch, existing information and control systems must be upgraded to support the new transaction levels and unbundled services. In addition, as regional coordination is implemented, through ISOs or other organizational means, information sharing and communication between transmission system control centers become even more important.

- Historically, there has been support for technology development through utility and industry collaborative research activities, including funding from DOE. There is consensus on the need for continued support for such technology development. The Task Force recognizes that there are major technological areas relative to reliability research and development (R&D) that need to be addressed. The Task Force is concerned that reliability-related R&D with long-term focus may be underfunded by market forces alone.

- Ancillary services are critical to the reliable operation of the bulk-power system. They are necessary to ensure stability of lengthy, complicated, and awkward transition period. During this period, as electric utilities open up their transmission systems to others and (in many cases) divest their generating assets, there is a critical need to be sure that reliability is not taken for granted as the industry restructures, and thus does not "fall through the cracks."

The Task Force is especially interested in seeing the reliability institutions becoming truly independent of commercial interests so that their reliability plans and actions are — and are seen to be — unbiased and untainted by the economic interests of any set of bulk-power market participants. In addition, the Task Force believes that these reliability institutions should, wherever possible, rely on competitive markets to encourage producer and consumer behaviors that maintain and improve transmission-grid reliability. The Task Force believes that the U.S. Congress should explicitly assign oversight of bulk-power reliability to the FERC, including the authority to coordinate North American reliability with the appropriate regulatory agencies in Canada and Mexico. Finally, because commercial and reliability interests are inextricably linked in the electricity industry, the Task Force urges the FERC to use its existing authority to regulate on reliability matters that intersect with commercial markets to ensure nondiscriminatory access to reliable transmission services until Congress takes action.

***Table S–1. Summary of Task Force recommendations and the entities principally responsible for their implementation.***

| Recommendation[a] | U.S. Congress | FERC[b] | DOE[c] | NERC/ SRRO[d] | System Operators[e] | Market Participant |
|---|---|---|---|---|---|---|
| ***Reliability Institutions and Authorities*** | | | | | | |
| 1. Modify the governance structure of the Reliability Councils. *[A]* | | | | X | | |
| 2. Undertake a Federal review of the Reliability Councils' existing policies and standards and organizational structure. *[A]* | | X | | | | |
| 3. Clarify authority and responsibility of the FERC and other reliability entities. *[A]* | X | | | | | |
| 4. Exercise existing authority to regulate reliability issues that intersect with markets. *[A]* | | X | | | | |
| 5. Grant more explicit statutory authority to the FERC to approve and oversee an electric industry SRRO. *[B]* | X | | | | | |
| 6. Create regional independent system operators (ISOs) or TRANSCOs to ensure both electric system reliability and competitive generation markets. *[C]* | | X | | | X | X |
| ***Ancillary Services*** | | | | | | |
| 7. Develop and implement clear and consistent national definitions of ancillary services. *[D]* | | X | | X | | |
| 8. Promote the creation of competitive markets for ancillary services wherever feasible. *[D]* | | X | | | X | |
| 9. Ensure that all bulk-power market participants provide or secure from third parties their fair share of ancillary services. *[D]* | | X | | | X | |
| 10. Ensure that providers of ancillary services receive compensation for services not provided through competitive markets. *[D]* | | X | | | X | |
| 11. Ensure that system operators have authority to compel provision of, and compensation for, needed ancillary services. *[D]* | | X | | X | | |
| ***Technical Issues*** | | | | | | |
| 12. Adopt an open standard for communications among control centers. *[E]* | | | | X | | |

***Table S–1. Summary of Task Force recommendations and the entities principally responsible for their implementation. (contd.)***

| Recommendation[a] | U.S. Congress | FERC[b] | DOE[c] | NERC/ SRRO[d] | System Operators[e] | Market Participant |
|---|---|---|---|---|---|---|
| ***Technical Issues (contd.)*** | | | | | | |
| 13. Adopt an open database access standard for control centers. *[E]* | | | | X | | |
| 14. Specify open information management protocols that will ensure interoperability of system operations records. *[E]* | | | | X | | |
| 15. Establish programs to address information assurance issues. *[E]* | | | X | X | | |
| 16. Implement a training program for system operators. *[E]* | | X | | X | | |
| 17. Develop risk-based analytical tools for reliability assessment and transmission investment planning. *[E]* | | | X | | | |
| 18. Undertake a study of technological alternatives to central station VAR support. *[E]* | | | X | | | |
| 19. Monitor research on reliability technologies and assure that gaps do not develop. *[E]* | | | X | | | |
| ***Transmission Incentives*** | | | | | | |
| 20. Monitor different pricing approaches to transmission services to learn more about advantages and limitations of the alternative methods. *[F]* | | X | | | | |
| 21. Develop methods for sharing generation and transmission planning information without passing commercially sensitive information between competitors. *[F]* | | | | X | X | |
| 22. Identify allowable range of transmission compensation structures and approve tariffs designed to compensate entities making cost-effective investments to relieve congestion. *[F]* | | X | | | | |
| 23. Encourage broad-based mechanisms to support basic and applied technology transmission research including tax credits for long-term research with broad public benefits. *[F]* | X | | | | | |
| 24. Monitor constrained interfaces to provide information to moderate rules and pricing to cost-effectively reduce constraints. *[F]* | | | | X | X | |

the grid and to prevent cascading outages in the event of an unplanned outage of a generating unit or transmission facility. Some ancillary services (for example, system blackstart capability) are necessary to recover from an outage. Historically, these services have been provided by vertically integrated utilities as part of their bundled electricity product. Increasingly, as the industry is being restructured, they are being supplied as separate services in a system that includes unbundled generation, transmission, and system control.

- Because most ancillary services are provided by generators, it should be possible to create competitive markets for them. Such services include regulation, load following, spinning reserve, supplemental reserve, backup supply, energy imbalance, and loss replacement. It may be possible to establish competitive markets for three additional services, voltage control, blackstart capability, and network stability. Regardless of whether markets or regulators determine the prices of some ancillary services, the system operator will remain the primary authority on how much of each service is required each hour and, for some services, the locations at which these services must be provided to the grid. The system operator will also determine how to select service providers — for example, through competitive bidding, long-term bilateral contracts, or FERC-approved tariffs.

## Task Force Recommendations

To ensure continued reliability of the bulk-power system in this environment of change requires a concerted effort by existing reliability institutions and State and Federal governments. To help achieve this goal, the Task Force developed a series of recommendations. Table S–1 summarizes these recommendations and the entities with primary responsibility for their implementation.

The Task Force is confident that the electricity industry, overseen by the Federal Energy Regulatory Commission (FERC) and a restructured self-regulating reliability organization (such as the planned North American Electric Reliability Organization [NAERO]), can and will maintain today's high levels of reliability. This confidence, however, does not imply complacency. There is much to be done, especially during what is turning out to be a

***Table S–1. Summary of Task Force recommendations and the entities principally responsible for their implementation. (contd.)***

| Recommendation[a] | U.S. Congress | FERC[b] | DOE[c] | NERC/ SRRO[d] | System Operators[e] | Market Participant |
|---|---|---|---|---|---|---|
| **State Issues** | | | | | | |
| 25. Explore formation of regional regulatory agencies to focus on interstate transmission enhancement needs, the avoidance of increased regulatory burdens and the replacement of multiple siting and other authorities with single regional siting authorities that are not subject to any State veto.[f] *[G]* | X | X | | | | |
| 26. Address uncertainty about who will pay for transmission enhancements and assure that State and Federal transmission pricing and cost allocation are coordinated and consistent. *[G]* | | X | | | | |
| 27. Ensure that customers have access to alternatives to transmission investment, including distributed generation and demand-side management, to address reliability concerns and that the marketplace and government requirements enable rational choices between those alternatives.[f] *[G]* | | X | | | X | |
| 28. For SRROs and regional reliability organizations, provide for government representation at governing board meetings and appropriate State representation in nominating and voting for board members. *[G]* | | X | | X | | |

**Footnotes**

[a]These recommendations were developed in a series of position papers approved by the Task Force. These papers are included as appendixes in Part II of this Final Report. The bracketed letter following each recommendation corresponds to the letter designation of the relevant appendix.

[b]The FERC is the Federal Energy Regulatory Commission.

[c]DOE is the U.S. Department of Energy.

[d]NERC/SRRO refers to a not-yet-formed self-regulatory reliability organization that would be the successor to the North American Electric Reliability Council.

[e]To the extent that the system operators are not *independent* of commercial interests, some of these responsibilities might be shifted to other entities.

[f]The Task Force did not reach unanimous agreement on this recommendation.

# Part I
# Final Report of the Task Force on Electric System Reliability

# I. Introduction

The U.S. electricity industry is in the midst of a major restructuring. A combination of technical, economic, regulatory, and political forces is transforming the industry from its traditional composition of vertically integrated[1] firms that have retail-monopoly franchises and are subject to heavy regulation, to an industry that is unbundled and dominated by competitive forces at the generation and retail levels (Fig. 1). All participants in the efforts to restructure the industry agree that reliability must be maintained in the future.

The need to address the reliability issue is urgent, and this urgency stems from at least five factors. First, electricity is a vital element of modern society both in our homes and in our businesses. Second, the U.S. Federal Energy Regulatory Commission (FERC) is well along in its efforts to create competitive wholesale power markets, to unbundle generation from transmission, and to provide nondiscriminatory access to all users of the grid. Many States are opening retail markets to generation competition. Third, the substantial changes in the character of participants in bulk-power markets, along with the significant increases in the number and complexity of transactions associated with greater competition could affect bulk-power reliability. Fourth, there is increased pressure to ensure that system operators make minute-to-minute decisions in ways that do not favor certain market participants over others, because many actions taken to operate the grid under conditions of heavy use have potentially significant financial implications for market participants. Finally, the diverse market pressures facing many of the participants in bulk-power markets could discourage compliance with reliability requirements that have long been adhered to on a voluntary basis by the utility industry.

[1]Vertically integrated utilities own, build, and operate powerplants, transmission systems, distribution systems, and customer-service operations all within a single company.

**A Fully Unbundled Electric Industry Model**

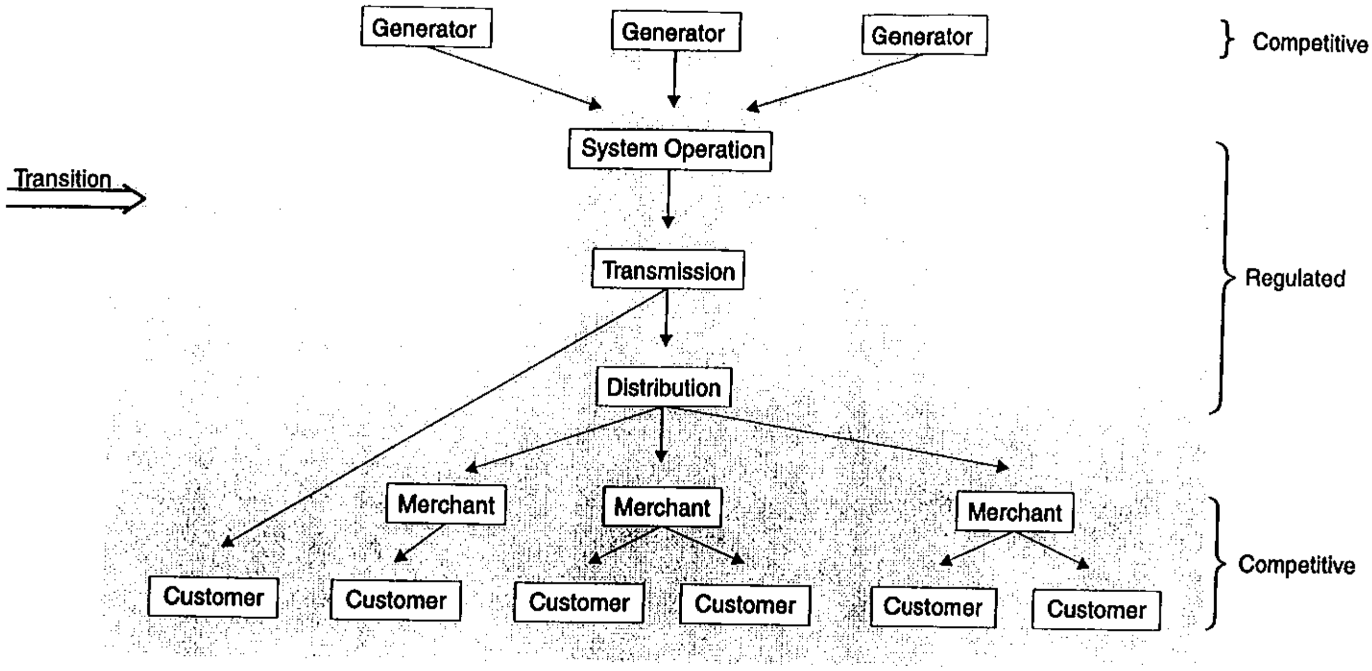



**Figure 1. *Electric Industry restructuring (contd.).*** *In the future, the competitive generation and merchant functions may be unbundled from the monopoly functions of system operation, transmission, and distribution.*

This report focuses on bulk-power reliability, rather than distribution-system reliability. The bulk-power system consists of generating units, transmission lines and substations, and system controls. Although the U.S. bulk electric power system has historically been responsible for only a small percentage of all power outages, the scope as well as the economic and societal consequences of such outages usually are much higher than those caused by distribution-system failures. That is, distribution outages are local whereas bulk-power outages are regional and therefore affect many more businesses and residences. For these reasons, and because Federal and State oversight responsibilities typically divide at the interface between the bulk-power system and the distribution system, the Task Force has focused on the former.

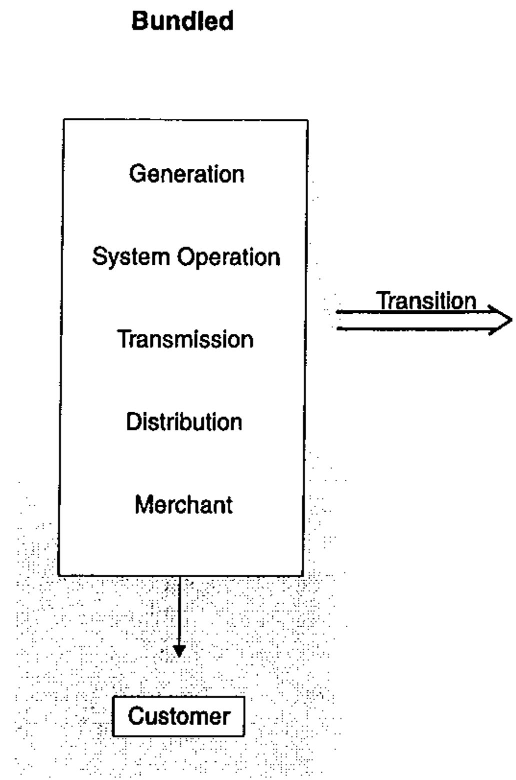



**Figure 1. *Electric Industry restructuring.*** *Today's vertically integrated utilities encompass all the functions shown here; wholesale transactions are regulated federally, while retail transactions are regulated by the States.*

The next section of this report provides background on reliability and the unique features of electrical systems. Section 3 discusses the reliability implications of the ongoing changes in the U.S. electricity industry. Section 4 presents the Task Force conclusions on bulk-power reliability and summarizes its recommendations to the U.S. Department of Energy (DOE). Section 5 discusses recent activities related to maintaining reliability. A glossary of key terms related to reliability is included to aid the reader in understanding the various technical terms surrounding reliability. Finally, Part II of this report includes the Task Force papers developed during the course of its deliberations.

# 2. Background

## What Is Reliability?

Reliability cannot be easily or unambiguously defined. A reliable electric system is one that allows for few involuntary interruptions of service to customers. While it may be easy to develop a historical record of how reliable an electric system has been in the past, it is much more difficult to determine how susceptible that same system will be to outages in the future.

Outages can be described in terms of number, frequency, duration, and amount of load (or number of customers) affected. Equally important, but much more difficult to quantify, are the economic consequences of any loss of electric service. A 10-minute loss of power to a residence causes the annoyance of having to reset digital clocks, but little or no economic cost is imposed. A similar outage for a computer-chip or a glass manufacturer might entail the loss of millions of dollars of output. Both might suffer significant economic loss and inconvenience if outages occur over extended periods of time.

Outages can occur from reliability problems on the bulk-power system, the distribution system, or both. Bulk-power system outages affect large areas and can have significant regional and national implications. Outages on the distribution system generally have localized effects.[2]

Reliability can be further described in terms of adequacy and security (Exhibit 1). *Adequacy* refers to the amount of resources available to supply the aggregate customer electrical demand and energy requirements. Adequacy issues tend to be long term in nature (days to years) and amenable to market incentives and interactions to

[2]The focus of the Task Force's efforts has been on reliability issues relating to bulk-power systems.

### *Exhibit 1. NERC's Reliability Definition*

The North American Electric Reliability Council (NERC), the primary guardian of bulk-power reliability, defines reliability as "the degree to which the performance of the elements of [the electrical] system results in power being delivered to consumers within accepted standards and in the amount desired." NERC's definition of reliability encompasses two concepts, adequacy and security. Adequacy is defined as "the ability of the system to supply the aggregate electric power and energy requirements of the consumers at all times." NERC defines security as "the ability of the system to withstand sudden disturbances."

In plain language, adequacy implies that there are sufficient generation and transmission resources available to meet projected needs plus reserves for contingencies. Security implies that the system will remain intact even after outages or other equipment failures occur.

address both the amount of electric power and energy service required by consumers and the amount of supplies built or otherwise brought to market to provide service. *Security* refers to the ability of an electric system to withstand sudden disturbances. The security aspect typically addresses emergency operations that occur within an already built system, take place over short times (seconds to hours), often require activation and operation of automatic protection devices, and generally involve intervention by a system operator. In plain language, adequacy implies that there are sufficient generation and transmission resources installed and available to meet projected needs plus reserves for contingencies. Security implies that the system will remain intact even after outages or other equipment failures occur.

In the past, utilities had the responsibility for all aspects of adequacy and security. As the industry moves to competition, and system operators are separated from ownership of and planning for generation, the responsibility for adequacy (ensuring sufficient generation capacity) and security (operating available capacity) will be separated.

## Key Features of Bulk-Power Electric Systems

Bulk-power systems include electrical generators, transmission networks, and control centers. These systems are fundamentally different from other large infrastructure systems, such as air-traffic control centers, natural-gas pipelines, and long-distance telephone networks. Electric systems have two unique characteristics:

- **The need for continuous and near-instantaneous balancing of generation and load,** consistent with transmission-network constraints. This requirement stems from the absence of technologies to store electricity easily and involves metering, computing, telecommunications, and control equipment to monitor loads, generation, and the transmission system, and to adjust generation output to match load or reduce load to match available generation.

- **The passive nature of the transmission network,** owing to very few "control valves" or "booster pumps" to regulate electrical flows on individual lines. Power flows according to the laws of physics, rather than from ownership, contract rights, or State boundaries. Control actions are limited primarily to adjusting generation output and to opening and closing switches to reconfigure the network.

These two unique characteristics lead to three reliability consequences that dominate nearly all aspects of power system design and operations:

- **Every action can affect all other activities on the grid.** From a reliability point of view, the activities of all players must be coordinated, often across large geographic regions.

- **Outages can increase in severity and cascade over large areas.** Failure of a single element can, if not managed properly, cause the subsequent rapid failure of many additional elements, disrupting interconnected transmission systems over a broad geographic area.

- **The need to be ready for possible contingencies, more than current operating conditions, dominates the design and operation of bulk-power systems.** It is usually not the present power flow through a line or transformer that limits allowable transfers of power, but rather the power flow that would occur if another element failed.

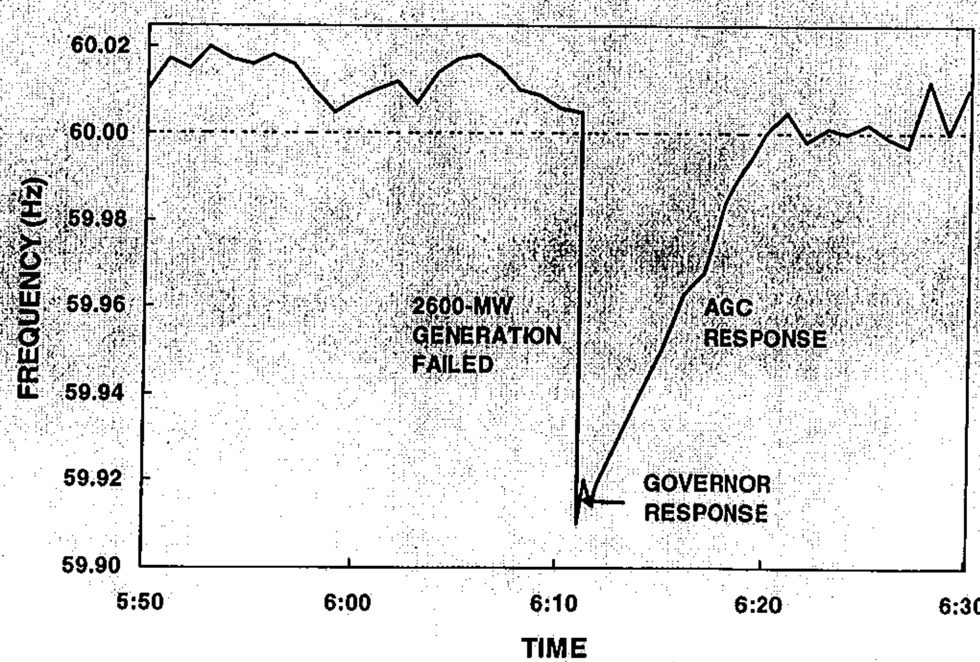
Exhibit 2 provides an example of how the electricity industry responds to these unique features; the example shows how operating reserves (extra generating capacity that can be brought online quickly) are used to protect against major generation and transmission outages and service disruptions.

The fundamental entity responsible for maintaining bulk-power reliability is the operator of the control area. Control areas are linked to one another to form Interconnections — electrical systems consisting of one or more control areas that have connecting transmission tie lines and operate in synchronism (that is, at the same frequency). Each control area seeks to minimize any adverse effect it might have on other control areas within the interconnection (and vice versa) by (1) matching its schedules with other

### *Exhibit 2. Application of Operating Reserves*

The electric system is designed to respond automatically and quickly to generation and transmission outages, as shown in the illustration below. In the example, the system was maintaining a relatively smooth operating frequency close to its standard value of 60 cycles per second (hertz, or Hz) until about 6:11. The failure of a 2,600-megawatt generating station at that time caused an immediate sharp decline in system frequency. This decline was arrested at just over 59.9 Hz, primarily because many electrical loads (such as motors) respond to such a frequency drop by automatically reducing their demand. It is unlikely that consumers connected to the electric grid at this time noticed that anything was amiss.

Reversing the decline required bringing extra generating capacity online to offset what had been lost. This process began when the governors on certain generators connected to the grid sensed the frequency drop and triggered a rapid increase in output. Then, in response to automatic-generation control signals from the control center, this increased output was boosted and sustained by the addition of more fuel to the boilers in those generating units that provide operating reserves. By 6:20, which was within the 10-minute response time required by the North American Electric Reliability Council, these reserves returned the electric system to its operating norm.




*Interconnection frequency before and after the loss of 2600-MW of generation* control areas (that is, how well it matches its generation within its area plus net incoming scheduled flows to the loads in the control area) and (2) helping the interconnection to maintain frequency at its scheduled value (nominally 60 hertz).

Today's approximately 150 control areas are operated by system operators who are primarily utilities, although a few are run by independent system operators (ISOs). Control areas vary substantially in geographic size and are grouped into regional reliability councils, of which there are 10 in the 48 contiguous States, most of Canada, and a small but growing portion of Mexico (Fig. 3). These reliability regions, in turn, are parts of the three primary Interconnections: Western, Electric Reliability Council of Texas (ERCOT), and Eastern.


**Figure 3.** ***Approximate locations of the 10 regional reliability councils.*** *The Western Systems Coordinating Council (WSCC) and the Electric Reliability Council of Texas (ERCOT) are each interconnections as well as reliability councils. The remaining eight councils are all located within the Eastern Interconnection.*

# Key Reliability Institutions

Within the United States, three sets of institutions play key roles in the area of bulk-power reliability: system operators, the North American Electric Reliability Council (NERC), and the FERC.

**System Operators and Security Coordinators** rely on communications with each other, access to essential system information, and real-time monitoring and control of certain facilities to maintain system reliability. When an emergency occurs on the system, the control area operator acts — both through communication and direct physical action — to ensure the integrity and security of the system. System operators take and direct others to take the actions necessary to "keep the lights on" and to protect the entire system from damage in the event of emergencies. In response to recent NERC requirements, 23 Regional Security Coordinators coordinate within the reliability regions and across the regional boundaries. Many of today's system-operation and security-coordination functions are managed by investor-owned utilities; others are run by public-power entities, ISOs, or regional reliability councils.

**NERC** was established in 1968. NERC's creation was a direct consequence of the 1965 blackout that left almost 30 million people in the northeastern United States and Ontario, Canada, without electricity. Electric utilities established NERC as a voluntary membership organization as an alternative to government regulation of reliability. NERC develops standards, guidelines, and criteria for ensuring system security and evaluating system adequacy. NERC has been funded by regional reliability councils, which adapt the rules to meet the needs of their regions. Through the work of its 10 regional councils, NERC has largely succeeded in maintaining a high degree of transmission grid reliability throughout the country. Historically, the reliability councils have functioned without external enforcement powers, depending on voluntary compliance with standards and peer pressure.

**The FERC** is the Federal agency having jurisdiction over the bulk-power market, including interstate transmission systems. As part of these responsibilities, the FERC implements policies to ensure that the owners and operators of bulk power transmission facilities under the agency's jurisdiction provide nondiscriminatory service to all power suppliers in wholesale power markets. Historically, the FERC has not had to involve itself with regulating reliability functions. Increasingly, some parties are calling upon the FERC to exercise its current authorities by addressing reliability issues that intersect with the commercial needs of the industry.

# Design Criteria

Design criteria for electric systems differ for adequacy and security. In the past, the amount of generation capacity needed to maintain adequacy, for example, usually was based on analyses performed by utilities, with the results subject to review and approval by State regulatory commissions. The amount of generating capacity maintained was typically intended to meet a planning standard under which the system suffered a blackout no more often than once every 10 years. In the future, generation adequacy decisions may be left to markets in some parts of the country. Generation capacity may be added only when market participants anticipate that future prices will justify the economic risks associated with constructing new generation. Therefore, it will be important to get the price signals right so that they encourage appropriate and timely investments and operating behaviors that support grid reliability.

System security, on the other hand, is generally based on deterministic, rather than probabilistic, analysis, that is commonly referred to as the N–1 contingency criterion.[3] This criterion requires that the system be able to withstand (continue to operate reliably after) the loss of any single element. Because there is usually insufficient time to respond to the sudden loss of a generator or transmission line through market interactions, technical standards are used to establish reserve requirements and operating requirements. Frequently, these requirements manifest themselves as constraints on the dispatch of generation or as location-based price differences. For example, if a transmission line is close to being overloaded (or the post-contingency loading would exceed the line's emergency rating), the system operator will either curtail those transactions that contribute most to the flows on that element, use line loading relief protocols that curtail transactions according to the FERC's service priorities, or use locational prices to encourage system users to respond appropriately. (Historically, these analysis, reliability, and commercial functions were all conducted within the same entity: the vertically integrated utility.)

[3]N refers to the total number of elements in the bulk-power system being considered in a contingency analysis. Thus, meeting the N–1 criterion means that the system can operate reliably if any one element is out of service.

# Maintaining Reliability in Today's Industry

In addition to the planning, construction, and maintenance of generation and transmission equipment, electric-system reliability depends on several activities performed by system operators and planners. These activities include:

- **Observing the network** — Monitoring present (real time) frequency, voltage, current, and power-flow conditions at each node and in each element to determine if failure of an element or voltage collapse is imminent.
- **Analyzing and modeling the system** — With the aid of computer models and data on current operating conditions such as current flows and voltages, anticipating conditions in elements (individual pieces of equipment such as lines and transformers) that are not directly observable; estimating what will happen if an element fails; determining whether a proposed transaction can be accommodated; and dealing with normal uncertainties, such as load-forecast errors and the effects of temperature and wind speed on real-time thermal limits.
- **Communicating and coordinating** — Coordinating with system operators in other control areas to ensure that activities do not threaten the integrity of the interconnected grid.
- **Taking control actions** — Maintaining system operation within acceptable limits (primarily changes in generation output, transmission switching to a lesser extent, and load shedding as a last resort).
- **Monitoring and enforcing compliance** — Ensuring that all market participants (generators, aggregators, marketers, transmission operators, and loads) are consistently meeting reliability requirements.
- **Planning for future conditions** — Making improvements and additions (such as new generation, transmission lines, transformers, load control, and FACTS[4] devices) to improve reliability and relieve constraints; improving communications and

[4]FACTS refers to flexible alternating-current transmission systems. These systems use high-speed solid-state technologies to control transmission equipment, thereby improving reliability and increasing capacity.

controls to enable more market participants to engage in reliability-enhancing activities; and improving ability to observe and model the system, thus allowing better utilization of existing resources.

- **Getting incentives and price signals right** — Ensuring that price signals and incentives (for generators, transmission, and loads) evoke reliability-enhancing behavior in the most economically efficient manner.

- **Protecting critical facilities** — Recognizing the need to take planning and operating actions that support the unique power requirements of critical facilities such as nuclear powerplants.

These activities take place at various levels of geographic aggregation. Some activities (primarily monitoring and control of distribution systems) occur at the sub-control area level, many at the control area, and some at higher levels of aggregation. The summer 1996 Western power outages revealed a need for greater regional coordination to improve reliability. In response to this need, NERC and the regional reliability councils created regional security coordinators. These 23 coordinators monitor regional power flows, focusing on the "big picture" that individual control areas cannot easily see.

## Time Scales

Actions to maintain reliability occur over very different time frames, from fractions of a second for the operation of automatic protection devices, to several years for planning additions to transmission and generation resources (Table 1).

While system operators must be able to respond quickly to disturbances, there are limits to their ability to intervene. Automatic protection devices are used where actions may be required before operator intervention is possible (for example, response to a lightning strike occurs automatically within less than a second).

As was shown in Exhibit 2 (page 8), it usually takes less than 10 minutes for normal service to be restored after a large generating unit unexpectedly fails. Other generating units on the grid — specifically, those capable of sensing a decline in system frequency — almost immediately increase their output for a brief period. At the same time, the control center automatically detects the frequency

# 3. Changing Industry Structure and Its Implications for Reliability

The 1992 Energy Policy Act might be considered the starting point for the electric-industry restructuring efforts now under way at both the Federal level (for wholesale competition) and within many States (for retail choice). As examples, the FERC issued a notice of proposed rulemaking on open-access, nondiscriminatory transmission service in 1995 and issued its final rule (Order 888) in 1996. And in March 1994 the California Public Utility Commission issued its "Blue Book," setting forth the State's plan to reform electricity regulation in that State; 2 years later, the legislature passed a bill (A.B. 1890) to accomplish those objectives. As of September 1, 1998, 18 States have mandated retail competition.[5]

## Potential Effects of Industry Restructuring

The restructuring of the U.S. electricity industry should have little effect on the physical requirements for maintaining bulk-power reliability, but will greatly affect who does what in ensuring system reliability. Maintaining reliability involves two sets of operations: normal operations and emergency operations. Markets can do much to maintain reliability and prevent outages (by preparing resources for use in emergencies) during normal operations. Markets alone may be much less effective during actual emergencies.

Response time is the key factor that will determine whether the independent actions of participants in competitive markets can perform some reliability functions or whether technical standards and direct control will be required. Roughly speaking, competition

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[5]U.S. Energy Information Administration. Details are available at the EIA Web site: www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.

decline and sends signals to those generators that provide operating reserves, prompting them to increase their output. These corrective actions begin more rapidly than responses dependent on human reflexes, though the system operators are able to intervene in such situations by redispatching generation, and (in some cases) transmission, resources.

The market can play a more significant role in forward-looking activities such as offering supplies to ensure sufficient operating reserves for the following hour and day. System operators and planners also need forecasts of system loads for day-ahead and week-ahead planning for reserves and longer term for maintenance and resource planning. Regional coordination for operating and planning activities is necessary to optimize efficient and reliable service. Finally, the planning for new generators and transmission system additions typically occurs from 1 to several years ahead.

***Table 1. Services that the traditional vertically integrated utilities performed that can affect bulk-power reliability***

| Function | Time scale | Service |
|---|---|---|
| Automatic protection | Instantaneous | Minimize damage to equipment and service interruptions caused by faults and equipment failures. |
| Disturbance response | Instantaneous to minutes to hours | Adjust generation, breakers, and other transmission equipment to restore system to scheduled frequency and generation/load balance as quickly and safely as possible. |
| Regulation and voltage control | Seconds to minutes | Adjust generation to match scheduled intertie flows and actual system load. Adjust generation and transmission resources to maintain system voltages. |
| Economic dispatch | Minutes to hours | Adjust committed units to maintain frequency and the generation/load area-interchange balance at minimum cost subject to transmission, voltage, and reserve-margin constraints. |
| Transmission loading relief | Minutes to hours | Curtail transactions and redispatch generation to reduce power flows through critical transmission elements. |
| Unit commitment | Hour ahead to week ahead | Decide when to start up and shut down generating units, considering unit ramp-up and -down rates, startup costs, and minimum runtimes and loadings. |
| Transmission scheduling | Hour ahead to year ahead | Schedule individual transactions and reservations of transmission capacity. |
| Maintenance scheduling | 1 to 3 years | Schedule and coordinate interutility sales and planned generating-unit and transmission-equipment maintenance to maintain reliability and to minimize cost. |
| Transmission cost. planning | 2 to 10 years | Design regional and local system additions to maintain reliability and to minimize |
| Generation planning | 2 to 10 years | Develop a least-cost mix of new generating units, retirements, life extensions, and repowering based on long-term load forecasts. |

is likely to work well for actions that occur a half an hour or more in the future. Given this lead time, buyers and sellers can find the price level for each service that will balance supply and demand. For shorter time periods, however, system control is still likely to be required. Technical standards may be needed to specify the amount of each service that is required and to establish metrics for judging the adequacy of service delivery; markets can then determine the least-cost ways to deliver the required services. Disturbance response and generation planning provide useful examples of the two ends of the temporal spectrum (Table 1 on page 14).

Many proposals for a restructured bulk-power system call for the creation of an *independent* system operator. Indeed, several States and regions, such as California, Texas, New York, the mid-Atlantic States, and New England, have already established ISOs. Among its responsibilities, an ISO has the ultimate authority to compel actions needed to maintain reliability in real time and to restore the system quickly and safely after an outage occurs. Although after-the-fact disputes may occur over who pays for what, there is no dispute about the ISO's responsibility, accountability, and authority to maintain reliability in real time. For example, if the ISO deemed it necessary to reduce flows on a particular transmission line, to take a line out of service, to reduce output at a particular generator, or to increase output at another generator, the operators of those pieces of equipment would be required to comply with the ISO's order. (Of course, the ISO would not be allowed to order actions that would violate safety or environmental laws, damage equipment, or jeopardize the operations of nuclear plants.) Such real-time operating authority is necessary to ensure system security in the future, as in the past.

Providing for system adequacy, however, may be different in the future than in the past. For example, generation planning will be entirely different from its past practice. Historically, utilities planned for and built powerplants to meet a predetermined reserve criterion, typically a 1-day-in-10-years loss-of-load probability or a minimum installed reserve margin. The State regulator then determined the extent to which the utility would recover the costs of these generators through rates charged to the utility's retail customers (who, because of retail-monopoly franchises, had no choice about whether to pay for this "extra" generation). In addition, these costs were generally reflected in embedded-cost rates that did not vary from hour to hour.

In the future, in a market-based model for providing adequate generation resources, decisions on retirement or repowering of existing generators and the construction of new units are likely to be made by investors with much less regulatory involvement. (Of course, State governments will still oversee the siting and environmental consequences of these decisions. But in States with retail choice of generation suppliers, markets (investors and consumers), rather than economic regulators, will decide which supplies are needed and economical.

These decisions will be made on the basis of trends in market prices and projected revenues from the sale of electricity relative to the construction and operating costs of the unit in question. Generators will be built when projected market prices of electricity are high enough to yield a profit. Prices in the future are likely to vary from hour to hour throughout the year, based on the units in operation each hour and the balance between unconstrained demand and supply online.

When demand begins to exhaust the available supply, prices will rise, sometimes sharply, which in turn will suppress demand and induce investment in new supply. Spot prices will stop rising only when constrained demand is brought down, supply is increased, or both. Although these spot prices are likely to be quite low for most hours, they may be very high for a few hours each year (for example, during unusually hot spring days and when large generators are out for planned maintenance). It is the level, frequency, and duration of these high prices that will signal markets to build more generating capacity, rather than the decisions of planners in vertically integrated utilities. This price volatility will also signal customers on the benefits of managing their loads in real time (Fig. 4).

In the approach outlined above, the economic paradigm of supply and demand elasticities replaces the engineering paradigm of planning reserve. A key concern with using only pricing to equilibrate demand and supply is that governments may choose to intervene and suppress prices in response to political pressures from consumers unhappy over the very high prices that will occasionally occur.[6] Such political intervention would undercut the market and chill investor decision to install additional generating capacity.

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[6]The dramatic price increases that occurred in the Midwest during June 1998 demonstrated this phenomenon. Those high prices, however, were not reflected in the regulated prices faced by the vast majority of retail customers. Consequently, there was very little demand reduction in response to these extremely high wholesale prices, and little political reaction since consumers did not see prices fly up in the bills they pay.

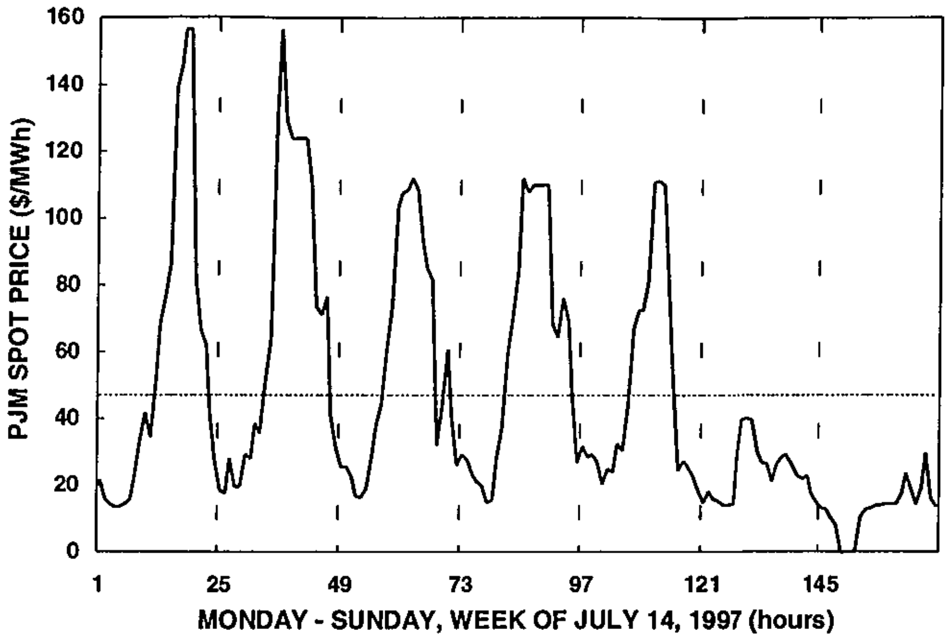


**Figure 4.** ***Hourly spot prices for electric energy in the mid-Atlantic region.*** *In the Pennsylvania–New Jersey–Maryland (PJM) Interconnection, prices ranged from a low of $0 to a high of $156, with an average of $47 per megawatthour for the week.*

Additionally, in some parts of the country, system adequacy is supported through market rules that require all load-serving entities to support or provide enough generating resources to cover their demand as well as a planning reserve requirement. Markets are the means by which these supply requirements are met. Some feel that mandating a minimum planning (installed generating capacity) reserve might have a similar market-distorting effect. New mechanisms for State governments to influence electricity markets, such as enforcement of standards of behavior for energy suppliers, may be necessary.

## Potential Reliability Benefits and Risks of Competition

Will increased competition at both the retail and wholesale levels improve or worsen reliability? This question, like many others related to restructuring the U.S. electricity industry, elicits strongly competing responses. Of course, the question itself is misplaced, because it implies that neither the industry nor governments do anything to ensure that reliability will be maintained in a restructured industry. And, as discussed in Section 5, NERC, the FERC, this Task Force, utilities, ISOs, and many others are working hard to identify changes that must be made to be sure that today's reliability levels are maintained or increased.

Those most concerned about the effects of competition on reliability are the people responsible for maintaining bulk-power reliability. They argue that electricity is not just another commodity and that its unique characteristics (discussed above) require tight coordination and centralized control. They believe that while markets might be able to provide for generation adequacy, markets cannot work well in ensuring transmission adequacy or system security because of its network attributes.

They argue that design and operation against the worst single contingency means that you cannot make the system just a little bit less reliable. Either you can meet the contingency criteria or you cannot. According to Loehr (1998), "It's a quantum kind of thing. Some have suggested that transmission criteria should be based on probability rather than the present deterministic principles. Actually, industry experts have been working on developing a practical system [to apply probabilistic methods to transmission security] for more than 30 years but so far have experienced limited success. The problem is that the probability of any single event approaches zero, while the number of possible events [contingencies] approaches infinity."

Finally, they note the increasing number and complexity of transmission operations, with more and more diverse market participants engaging in more and more transactions. Utilities throughout the country report substantial increases in the number of schedules and schedule changes. Formerly, these transactions were primarily with adjacent utilities. Now they are with a variety of entities, including neighboring and distant utilities, independent power producers, and power marketers. For example, the number of transactions handled by Duke Power more than doubled between 1995 and 1996, increased another 50 percent between 1996 and 1997, and is increasing by about 40 percent in 1998 (Fig. 5). Modifying computer hardware and software and the associated operating practices to handle more transactions is a transitional issue, not a long-term problem.

Others, especially power marketers and large industrial customers, point to the potential benefits of increased reliance on markets to

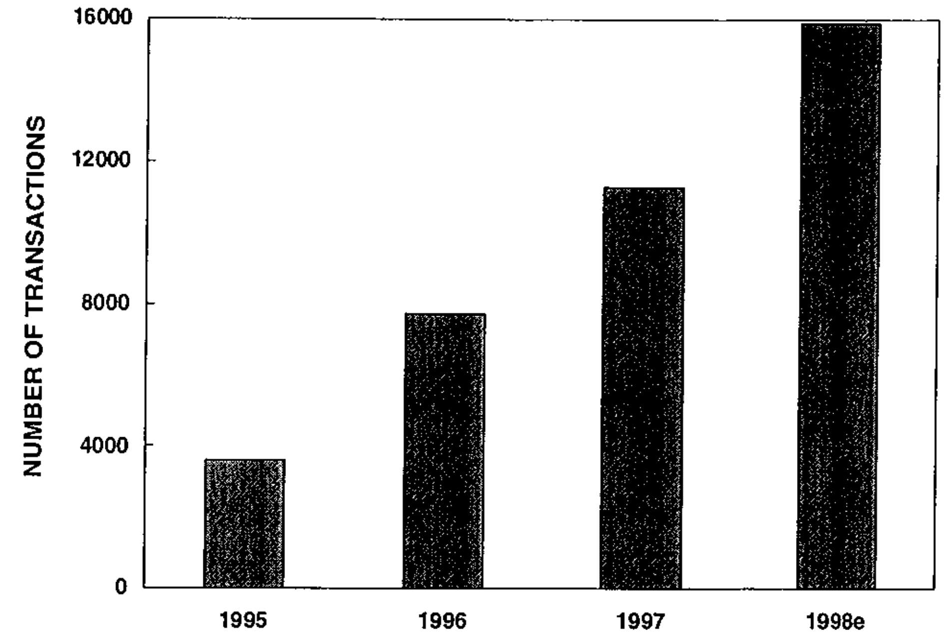


**Figure 5.** ***Wholesale transactions handled by Duke Power in North and South Carolina.*** *The 1998 estimate is based on data for the first 4 months of 1998.*

deliver reliability services. Rather than continue to use the traditional command-and-control approach to reliability, they suggest the use of economic incentives to encourage appropriate behavior on the part of electricity-market participants (Hirst 1997). For example, the traditional approach to ensuring that sufficient operating reserves are available has been to require each utility, regardless of the outage performance of its individual generating units (for example, the frequency and duration of forced outages), to maintain specified amounts of generating capacity for spinning and supplemental reserves. Adjusting reserve requirements to reflect generating-unit performance and using economic incentives (such as competitive markets) to define reserve requirements and to buy and sell such reserves could either improve reliability at no increase in cost or maintain current reliability levels at a lower cost.

Customer response to real-time pricing signals could also help to improve reliability. Rather than rely solely on technical standards to set minimum amounts of installed generating capacity, why not let the interactions of suppliers and consumers and real-time pricing decide how much capacity is needed, where, and when? High prices will encourage the construction of new generating units and the prompt restoration to service of existing units that are offline. Similarly, with real-time price information, consumers can decide

whether they want to conserve or reduce their usage at times of high prices. Together, these supply and demand responses to price will reduce the need to maintain expensive generating capacity that is only rarely used. Thus, economics can substitute for engineering to maintain real-time reliability when demand would otherwise exceed supply.

Whether reliability can best be maintained by relying on markets or on technical standards is not really the issue. The challenge to the electricity industry is to find an appropriate mix of economic incentives and performance standards that maintain reliability at the lowest reasonable cost. Indeed, much of the reliability related activities of NERC, the FERC, and others seeks to do just that.

# 4. Task Force Findings and Recommendations

*These findings and recommendations are detailed in a series of papers contained in Part II of this report.*

Because electricity is such a critical element of modern society, bulk-power reliability must be maintained at a high level. However, the many changes under way in the structure, regulations, and operations of the U.S. electricity industry complicate achievement of that goal.

As the electricity industry is transformed from one dominated by highly regulated, vertically integrated, entities with monopoly franchises to one characterized by substantial competition at both the wholesale and retail levels, the North American reliability institutions, practices, and payments must also change. Fortunately, many of the necessary changes are already under way. The following subsections summarize the findings and recommendations agreed upon by the Task Force during its 21-month deliberations.

## Reliability Institutions and Authorities

### General

In July 1997, the Task Force approved its *Interim Report* that focused on institutional changes and presented the key findings and recommendations reached as of that point in its work. The Task Force findings included the following:

- Restructuring the electric industry offers economic benefits to the Nation.
- While the changes brought about by restructuring are complex, the reliability of the system need not be compromised

provided appropriate steps are taken. Transmission grid reliability and an open, competitive market can be compatible.

- The viability and vigor of the commercial market must not be unnecessarily restricted. The market forces being introduced now depend on fair and open access to the transmission grid.
- Commercial markets should develop economic practices consistent with the ingenuity and mutual interest of the participants. However, grid reliability must be maintained through disciplined technical standards and practices.
- Reliability standards must be clear, transparent, nondiscriminatory, enforceable, and enforced. Compliance must be mandatory for *all* entities using the bulk power system.
- Regulatory oversight is necessary to ensure compliance with reliability policies and standards and to resolve disputes.
- It is reasonable and practical to build on the experience and reliability standards developed by the reliability councils over the past three decades. However, these standards as well as the reliability councils' own systems of governance must be modified to accommodate the complexities of the competitive market.
- Grid reliability depends heavily on system operators who monitor and control the transmission grid in real time. To ensure competitive use of the grid, system operators must be independent from and have no commercial interests in electricity markets.
- Because bulk-power systems are regional in nature, they can and should be operated more reliably and efficiently when coordinated over large geographic areas.
- The reasonable and necessary costs for maintaining the reliability system should be fully recoverable and equitably distributed.
- Transmission grid reliability is a North American issue; the reliability relationships with Canada and Mexico must be preserved. Consultation with Canadian and Mexican governments is important for ensuring reliability in the interconnected North American bulk-power market.

The *Interim Report* included the following Task Force recommendations:

- The reliability councils expedite — to the fullest extent possible and consistent with ensuring sound results — the modification of their governance structures to ensure fairness and lack of domination by any single industry sector.
- The FERC undertake a review of the reliability councils' existing policies and standards that affect the operation of an open electricity market and undertake a review of the reliability councils' organizational structures and governance. This proposed role for the FERC is important in order to make reliability standards enforceable and to ensure that reliability standards and practices are not misused in ways that would be discriminatory in the competitive market. Given the considerable demands currently faced by the FERC, additional resources may be required by the agency in order to undertake this role.
- Federal legislation is necessary to further clarify the authority and responsibility among the FERC and other entities for overseeing, setting, and enforcing reliability standards.

## Self-Regulating Reliability Organizations

In November 1997, the Task Force adopted its second report, *Maintaining Reliability Through Use of a Self-Regulating Organization*, focusing on the content of proposed new Federal legislation that would authorize the FERC to approve and oversee a single, international self-regulating reliability organization (SRRO), such as a reformed NERC. The impetus for this report was the belief that the traditional system of peer-reviewed standards coupled with voluntary compliance was unsustainable in the increasingly decentralized and competitive U.S. electricity industry.

The Task Force agreed with the NERC Board's decision, in January 1997, to require adherence to NERC rules and procedures. The Task Force questioned whether NERC has the authority to require industry participants to abide by its rules and procedures in the absence of Federal legislation. (Indeed, the case before the FERC brought by the Coalition Against Private Tariffs, discussed below in Exhibit 3, vividly demonstrates this concern.) In response to these concerns, the Task Force suggests that the U.S. Congress adopt legislation to clarify such authorities and enable the FERC to approve an international self-regulating organization to establish

### *Exhibit 3. Reliability Conflicts Before the Federal Energy Regulatory Commission*

The FERC's recent actions on reliability may have been stimulated by a complaint filed by a group of power marketers and large industrial customers in August 1997 (Coalition for a Competitive Electricity Market and Electricity Consumers Resource Council 1997). The complaint, about NERC's interim Transaction Information System and NERC's requirement for this "tagging" information, illustrates well the potential conflicts between reliability and commerce, especially when those making the reliability decisions may also have commercial interests in electricity markets. The tagging information is provided by the commercial marketing entities that seek to transmit power from one control area to another; the information is provided to the sending and receiving control areas. NERC's requirements include the interchange schedule size (MW); start and stop times and ramp rates; generation reserves; and transmission service arrangements. The complaint alleged that (1) absent prior approval from the FERC, NERC lacks authority to require its members to impose such a condition on wholesale trade and (2) some utilities are using this NERC requirement to impede wholesale competition. The Coalition is concerned because NERC requires that the load-serving entity is the one responsible for providing the tagging information. But if that entity (almost always the local distribution company) does not do so, the power marketer or seller may be the one that loses.

In response, NERC (1997a) claimed that its current actions are a continuation of its 30-year efforts to maintain bulk-power reliability. NERC explained that this additional tagging information is "properly a part of NERC's operating policies and procedures because it provides information required by control area operators to physically match generation and load and thus maintain the integrity of the Interconnections." This NERC operating procedure is independent of the FERC's open-access information system. NERC distinguishes between (1) requesting and reserving transmission service (the financial deals), which is under FERC jurisdiction, and (2) setting up and implementing interchange schedules between control areas (the physical energy transfers), which traditionally have been NERC's responsibility. These physical actions, matched between the sending and receiving control areas, are essential to maintain frequency at its reference value and to prevent overloading of transmission lines.

In April 1998, the FERC (1998c) concluded "that the establishment by NERC of a requirement to report certain information does not, in and of itself, require a change to the terms and conditions of the Open Access Tariffs on file with the Commission because the information which NERC requires is consistent with the information that the tariffs already require. As a result, we will dismiss the Coalition's filing. However, the question of whether information may be collected is different from the question of what actions can be taken under a utility's tariff in response to the information."

electric reliability standards similar to the National Association of Security Dealers in the securities industry.

The Task Force agreed that Federal legislation should grant more explicit statutory authority to the FERC to approve and oversee an electric industry SRRO having responsibility for bulk-power reliability standards. Such legislation should provide for the following:

- FERC review and approval of a proposal for an electric industry SRRO.

- FERC implementation of mandatory reliability standards for the Nation through rulemakings in accordance with the Administrative Procedures Act.

- FERC jurisdiction for reliability of the bulk-power system including those portions owned or operated by Federal, cooperative, and municipal utilities and all other entities participating in the electricity market.

- FERC review and approval of all SRRO mandatory standards including specified incentives and penalties for compliance.

- FERC ability to require the SRRO to develop, modify, or replace standards when necessary.

- Mandatory application of reliability standards to all entities using or operating the bulk-power system.

- SRRO enforcement of mandatory standards, including imposition of penalties or fines, subject to FERC review.

- FERC authority to expedite or temporarily waive procedures when necessary to address an ongoing or imminent reliability problem.

- When requested by the SRRO or on its own initiative (for example, in an emergency situation or stemming from a complaint), FERC review of any SRRO governance or process issues, standards, or SRRO enforcement action.

- Sufficient resources for the FERC to administer its new responsibilities including the authority to levy necessary fees on the industry and access to industry computer models, data, and transmission experts.

In the meantime, the Task Force encourages the FERC to use its existing authority to regulate issues at the intersection of reliability and commercial market operations.

## Independent System Operators

In light of the considerable interest in creating ISOs or TRANSCOs, the Task Force adopted a third report, *The Characteristics of the Independent System Operator*, in March 1998. This report set forth the Task Force's views on the purposes, features, and governance of such entities. The Task Force believes that ISOs are significant institutions to ensure both electric system reliability and competitive generation markets.

With respect to the purpose of an ISO, the Task Force recommends that such entities operate the regional transmission network and ensure reliable operation in accordance with SRRO standards and comparable access in accordance with FERC tariffs and policies (for the U.S. participants). The functions of an ISO include operation and planning for the bulk-power system, implementation and enforcement of standards and guides developed by the SRRO, and monitoring for regional security. For example, ISOs should ensure the reliability and adequacy of the offsite power supplies to nuclear plants. With respect to governance, the Task Force recommends a board of directors that is either representative of all participants such that no set of participants can control the board, or that is independent of participants (that is, have no commercial interests in electricity markets within the region).

While most Task Force members favor formation of large regional ISOs, the Task Force stopped short of recommending that mandatory ISOs be formed throughout North America. However, where ISOs are formed, they should encompass the transmission systems of the Federal power marketing agencies, public-power entities, and rural electric cooperatives, as well as those of the investor-owned utilities. Federal legislation may be required to permit such participation from public-power entities.

## Ancillary Services

In May 1998, the Task Force adopted another report, *Ancillary Services and Bulk-Power Reliability,* dealing with the ancillary services that are critical to the reliable operation of the bulk-power system. They are necessary for normal operations (for example, voltage control, regulation, load following, and energy imbalance); to ensure stability of the grid and to prevent cascading outages in the event of an unplanned outage of a generating unit or transmission facility (for example, operating reserves); and to safely and promptly restore systems and services after a major disturbance occurs (for example, system blackstart capability). These ancillary services are rarely optional. Because these ancillary services are essential for maintaining bulk-power reliability, the Task Force is concerned that their availability, production, and deployment must be maintained.

The Task Force made the following suggestions:

- The SRRO, subject to FERC jurisdiction, should develop and implement clear and consistent national definitions of ancillary services. These definitions should include methods to measure the capability and the delivery of each service as well as penalties for noncompliance with these performance metrics. These definitions should be sufficiently flexible to encourage innovative ways to provide the service (for example, automatic control of some customer loads could serve as alternatives to generation for spinning reserve). Periodically, the FERC should consider additions, deletions, and modifications to the six ancillary services included in Order 888. This expansion could apply to services such as system blackstart, network stability, load following, and perhaps others.

- The FERC and the system operators should promote the creation of competitive markets for ancillary services wherever feasible. Competitive markets offer the possibility of increased reliability at lower cost, as well as fewer regulatory controversies over embedded-cost pricing. When it is demonstrated that a sufficiently competitive market exists for an ancillary service, the FERC's price-setting role for that service could be minimal. Where locational requirements are strict and ancillary service providers are limited, competitive markets may not be feasible. In such cases, the FERC should continue to regulate the provision and pricing of these services.

- The FERC and the system operators should ensure that all bulk-power market participants provide (or secure from third parties) their fair share of ancillary services, especially those required for bulk-power reliability. Where costs can be assigned to specific customers (for example, for backup supply or dynamic scheduling), those customers should pay the full costs.

- The FERC and the system operators should ensure that the providers of ancillary services have the opportunity to receive fair compensation for the prudently incurred costs to produce those services not provided through competitive markets. The FERC's role in setting prices will likely be a function of the independence of the system operator from commercial interests and the strengths of competitive markets for these ancillary services. Where competitive markets exist, the FERC jurisdictional utilities should no longer be obligated to offer these services at embedded-cost prices.

- The FERC and the SRRO should ensure that system operators have sufficient authority to compel generation and transmission owners to supply (and customers to pay for) the amounts and characteristics of each service determined by the system operators to be required for reliability and to support commercial transactions. The system operator must be the final authority on how much of a service is required and, in some cases, the locations at which that service must be provided to the grid. The system operator need have no authority over the prices of most services. To the extent that system operators have no commercial interests in electricity markets, the FERC's oversight could likely be reduced.

## Technical Issues

In May 1998, the Task Force adopted a report on technologies, entitled *Technical Issues in Transmission System Reliability.* The report discussed the emerging technical challenges of an increasingly competitive industry — in particular, those associated with substantial increases in the number of transactions and greater long-distance power flows. These changes in the operation of power grids can increase the effects of local disturbance on the synchronism of the generators connected to the grid. (Recall that all the generators within an Interconnection are coupled together and rotate at the same speed.) Disturbances can, if not corrected quickly, lead to growing instability and major outages as units trip offline.

The Task Force was briefed on the reliability research programs of the Electric Power Research Institute (EPRI), vendors, and DOE. Historically, technology R&D has been supported through utility and industry collaborative activities, including funding from DOE. The Task Force agrees on the need for continued support for such technology development.

As the electricity industry becomes more competitive, there is likely to be both a reduction in funding from traditional sources and a need to develop alternative technologies for reliability management. Specifically:

- DOE funding for reliability and transmission has declined substantially.
- Direct utility research funding is being eliminated or significantly reduced.
- EPRI's focus on transmission and distribution research has shifted from long-term to near-term payoff.

- Responsibility for reliability management is changing, and there are questions about what entities will be responsible for technology investments.

- New tools and technologies are needed to manage reliability in a more competitive market. For example, unbundling voltage support may require use of distributed technologies.

The Task Force recognizes that there are major technological areas relative to reliability R&D that need to be addressed. The Task Force is concerned that long-term reliability-related R&D may be underfunded by market forces alone. DOE should monitor the funding gap from traditional sources and the need for alternative technologies to ensure this need is addressed and a technology gap does not develop in reliability-management technology.

Fortunately, various reliability-management technologies are being developed that can reduce the frequency and severity of bulk-power disturbances. These technologies include the following: communications, databases, control systems, and information management; planning tools that can rapidly assess a broad range of possible contingencies; alternatives to generating units to provide fast voltage support; and a variety of energy storage, distributed generation, electronic controllers, and underground delivery system technologies.

The Task Force adopted several recommendations that support the timely and effective use of reliability-related technologies:

- An appropriate, open standard for communications among control centers be adopted by the SRRO and endorsed by the FERC.

- An appropriate, open database access standard for control centers be adopted by the SRRO and endorsed by the FERC.

- The SRRO specify open information management protocols that will ensure the complete interoperability of system operation records in compliance with FERC Orders 888 and 889.

- DOE, in collaboration with the SRRO, EPRI, and other Federal agencies, examine information assurance issues for the interconnected electric system and establish appropriate cooperative programs to address these issues as warranted.

- An appropriate training program for system operators be developed by the SRRO and endorsed by the FERC.

- Appropriate entities, such as DOE, in cooperation with the electric power industry, develop risk-based analytical tools for reliability assessment and transmission investment planning.

- DOE undertake a comprehensive study of technological alternatives to central-station volt-amperes reactive (VAR) support, their potential impact on bulk-power system reliability, and impediments to the use of such alternatives. The Task Force recommends that DOE consult with various industry participants and report the results back to the FERC and the SRRO.

- DOE carefully monitor research on reliability technologies and make appropriate recommendations to the FERC and Congress to ensure that gaps do not develop.

## Transmission Incentives

In July 1998, the Task Force adopted a report, *Incentives for Transmission Enhancement*, on issues related to investments in transmission-system reliability. The Task Force is concerned that State and Federal-level regulation is not doing enough to promote and shape sound investments in grid reliability given pressures for short-term cost-cutting at the expense of societal interests in reliability.

Two fundamental problems arise when trying to decide whether to make capital investments to alleviate congestion. The first problem is that there is no agreement on the appropriate way to price transmission to create efficient price signals for investment (supply) or use (demand). The Pennsylvania–New Jersey–Maryland Interconnection is using location-based marginal energy prices and firm transmission rights as the means for indicating the need for and cost-effectiveness of investments in transmission enhancements. In other regions such as New England, market participants have adopted a region-wide postage-stamp pricing system for transmission, with cost allocation for new transmission enhancements still in discussion. There is no national consensus on the correct approach, or on which approach creates the proper incentives for investment. However, with a variety of pricing approaches in place across the country, experience will increase our understanding of the advantages and disadvantages of the different approaches to transmission pricing.

The second problem is that competing options for relieving congestion operate in different markets with different structures: generation and demand-side solutions operate primarily in competitive markets, while transmission remains largely a regulated monopoly service. When a single investment (for example, a generator) is selling services into both competitive and regulated markets, it is difficult to unambiguously determine the appropriate allocation of costs between those markets and to establish appropriate incentives for efficient investments (or product substitution) in those markets. Uncertainty may lead to underinvestment or cross-subsidization.

Regardless of the operating and pricing structure adopted, investors will require clear and stable rules to encourage them to risk their capital. As well as being clear, the economic signals need to be adequate to induce appropriate investments. The Task Force made the following findings and recommendations on incentives for transmission expansion and enhancement:

- At present, there is no national consensus on the appropriate way to price transmission services to provide optimal incentives for both investment in transmission facilities and the demand for transmission services. Given the lack of consensus, it is appropriate and desirable that a variety of approaches are being tested around the country. The FERC should monitor progress with these different pricing approaches so that we can learn more about the advantages and limitations of the alternative methods.

- Energy production will be increasingly market based. Generation investment decisions will be made by commercial entities assuming the risks associated with their decisions. But the viability of a generator depends in part on the market it is selling into. If that market is influenced by congestion, the investor will want information concerning how long that congestion is likely to last. Similarly, decisions concerning congestion-relief investments should be influenced by expectations concerning future generator locations. Methods for sharing generation and transmission planning information, without passing commercially sensitive information between competitors, should be developed.

- The FERC should approve tariffs or pricing approaches designed to compensate those entities making cost-effective investments to relieve congestion. While allowing for regional variations, the FERC should explain the range of transmission compensation structures it will allow, and the extent to which generation investments that perform transmission functions are subject to rate regulation as transmission or, conversely, the extent to which transmission investment that adds to generation capacity in the region qualifies for unregulated market prices and rates of return.

- Without a robust open market addressing grid congestion, many believe there is minimal incentive for commercial entities to conduct or pay for long-term transmission research. Long-term research to advance transmission technology would then be in the public interest and should be open rather than proprietary. Broad-based mechanisms to support basic and applied technology research should be encouraged, including tax credits for long-term research with broad public benefits.

- Monitoring outcomes of changes in the wholesale electricity market is important to determining the effectiveness of the system operator and its rules. Just as NERC makes assessments today of regional reliability and identifies sensitive situations, the national reliability organization should assess interfaces that are constrained presently and review these assessments periodically. The system operator can use this information to modify its rules and pricing to cost-effectively reduce constraints.

## State Issues

In July 1998, the Task Force adopted a report, *Issues of Federalism in Transmission System Reliability*. The report discusses State and regional responsibilities for the evaluation and siting of transmission enhancements and alternatives, ratemaking and cost-recovery issues associated with transmission expansion, and State government participation in a new national SRRO and its regional reliability organizations (RROs).

Historically, State governments have had authority over the siting of transmission facilities. Conflicts may arise in the future if the benefits of transmission expansion are primarily regional but the decisions and costs are primarily local. The Task Force supports[7] the establishment of new regional regulatory agencies (RRAs) if Federal

[7]The Task Force did not reach unanimous agreement on this recommendation.

legislation would (1) establish criteria that must be met by the RRA; (2) authorize the FERC to approve an RRA once the FERC certifies that the RRA meets the criteria; (3) authorize the FERC to give deference, where appropriate, to approved RRAs; (4) specify that the FERC has regulatory oversight over RRAs in all matters except siting; and (5) require that RRA member States relinquish jurisdiction over any issue addressed by an RRA and ensure that no State have veto power over any decision of the RRA.

In addition to the controversies over appropriate transmission-pricing approaches discussed above, the Task Force expressed concern about who pays for transmission enhancements. Would local retail customers be called upon to pay for transmission investments that were made primarily to increase regional power flows? State regulators are unlikely to approve such investments if they think that retail customers in their State will pay a disproportionate share of the costs. RRAs could help resolve such potential conflicts by balancing the interests of retail and wholesale customers in the various States as well as those of the entity making the transmission investment. In addition, RRAs could ensure that alternatives to transmission expansion, such as distributed generation and demand-side management programs, are considered.

The SRRO and RRO governing boards might include stakeholder seats, independent seats, or both. Regardless of the structure, the Task Force believes that States should be represented in the process of nominating and voting for board members. State and Federal governments should have nonvoting (ex-officio) representation at all board meetings. States would participate in the selection of board members for a particular RRO only if the State was within that region. The board compositions and voting and nomination rules should be addressed by the FERC when it reviews the SRRO for approval.

The Task Force made the following recommendations in this area:

- Exploring formation of RRAs to provide an institutional focus on interstate transmission enhancement needs, the avoidance of increased regulatory burdens and the replacement of multiple siting and other authorities with single regional siting authorities that are not subject to any State veto.[8]

[8]The Task Force did not reach unanimous agreement on this recommendation.

- That the FERC undertake an initiative to address uncertainty about who will pay for transmission enhancements and to assure that State and Federal transmission pricing and cost allocation are coordinated and consistent.

- That RRAs ensure that customers have access to alternatives to transmission investment, including distributed generation and demand-side management to address reliability concerns, and that the marketplace and the RRA's standards and processes enable rational choices between those alternatives.[9]

- That the FERC, when reviewing the SRRO for approval and when reviewing any agreement between the SRRO and an RRO, ensure opportunity for State and Federal government representation at governing board meetings and appropriate State representation in the process of nominating and voting for board members.

## Other Issues

Although not covered explicitly in the Task Force papers, the group agreed that DOE should review the experiences with electric-industry restructuring in other countries. Although the initial structures and operations were often quite different in other countries (in particular, many countries began with a single, government-owned electric utility rather than the 3,000 diverse entities that characterize the U.S. system), there may be opportunities to learn from the experience of others. This review should focus on any changes in bulk-power reliability levels and on institutional and operational changes in reliability occasioned by the restructuring.

[9]The Task Force did not reach unanimous agreement on this recommendation.

# 5. Recent Institutional Responses to Reliability Concerns

Many of the legislative and regulatory plans to restructure the U.S. electricity industry do not deal explicitly with reliability. Fortunately, efforts under way at DOE, the FERC, and NERC address bulk-power reliability explicitly.

## U.S. Department of Energy

In addition to its sponsorship of this Task Force on Electric System Reliability, DOE prepared legislation on behalf of the Clinton Administration. Disputes between the new and traditional participants in bulk-power markets (Exhibit 3 on page 26) illustrate well the need for the U.S. Congress to expand and clarify the FERC's role with respect to bulk-power reliability. Based largely on the early recommendations of this Task Force, the Administration's proposed Comprehensive Electricity Competition Act (DOE 1998) offered four legislative changes to the Federal Power Act concerning the FERC's authority over bulk-power reliability:

- Section 201 would extend the FERC's jurisdiction over transmission services (but not the power business) to municipal, other publicly owned, cooperative, and Federal utilities.
- Section 202 would permit the FERC to approve interstate compacts that establish regional transmission planning agencies that facilitate coordination among States concerning the siting of new transmission facilities.
- Section 204 would give the FERC the authority to establish independent system operators and to require utilities to relinquish control of their transmission facilities to the ISO.

- Section 501 would give the FERC the authority to register and oversee an electric reliability organization to prescribe and enforce mandatory reliability standards, which would apply to all users of the bulk-power system.

## Federal Energy Regulatory Commission

The FERC has explicit authority over the commercial aspects of wholesale transactions and interstate transmission. The FERC's authority with respect to bulk-power reliability is more ambiguous. However, commercial transactions and reliability are unavoidably intertwined.

In early 1998, the FERC (1998a) opened an inquiry on reliability, perhaps stimulated in part by conflicts between transmission customers and transmission owners over reliability rules (Exhibit 3) and the initial recommendations of this Task Force. Its announcement of a February 1998 technical conference on reliability suggested three alternative processes for addressing reliability in FERC regulations:

- All transmission providers that are members of a reliability organization follow that organization's rule with no FERC approval. Transmission customers are free to challenge those rules under Section 206 of the Federal Power Act.

- All jurisdictional utilities that are members of a reliability organization would file the reliability rules with the FERC as amendments to their transmission tariffs.

- The reliability organization would file a request for a declaratory order with the FERC that the rule is just and reasonable.[10]

Participants in the technical conference expressed considerable disagreement over whether the FERC should issue a new rule on reliability; NERC was strongly opposed to this idea because it is

[10]In June 1998, NERC filed such a request with the FERC for a declaratory order on NERC's transmission loading relief procedures. This request raised the same kinds of controversies over commerce and reliability as did NERC's tagging procedures (Exhibit 3).

currently in the midst of so many changes. Others, including power marketers and large industrial customers, expressed concern about NERC's continued lack of a fully balanced membership on its board and many committees. These entities were also concerned about the possibility that the 23 security coordinators, most of which are utilities, might engage in discrimination. Overall, there seemed to be some consensus among the conference participants in favor of Federal legislation giving the FERC oversight over a self-regulating reliability organization.

The FERC (1998b) subsequently initiated another investigation, this one on ISOs. One of the six panels for an April 1998 technical conference dealt with reliability. The FERC's questions for the panel participants asked whether reliability rules should be national or regional, whether ISOs would enhance bulk-power reliability, what the relationship between an ISO and regional reliability council would be, and whether the ISO should be the regional security coordinator. Participants in the technical conference expressed the same kinds of diverse views as those offered at the earlier conference on reliability. In general, participants favored formation of large regional ISOs both to ensure open access to transmission and to maintain reliability.

## North American Electric Reliability Council

During the past few years, NERC has begun to transform itself into an entity intended to meet the bulk-power reliability needs of a competitive and unbundled electricity industry. These changes include "universal participation, more detailed and uniform reliability standards that can be put in place quickly, independent monitoring of reliability performance, and the *obligation* to support, promote, and comply with NERC's Policies."

In the summer of 1997, NERC formed a blue-ribbon panel of experts, called the Electric Reliability Panel (1997), to help define the future course for ensuring bulk-power reliability. The panel's December 1997 report made several recommendations to the NERC Board that focused on independent governance, inclusive membership, mission, mandatory compliance and enforcement with reliability standards, and creation of a self-regulating organization. Those recommendations were consistent with the recommendations of this Task Force.

The NERC board, in response to the panel's report, appointed four task groups to offer proposals on governance, standing committees, government interface, and funding for the new NAERO. The four groups issued reports and recommendations that were considered at the NERC board's May 1998 meeting (NERC 1998b).

In July 1998, the NERC board approved the steps required to convert NERC (a voluntary organization) into NAERO (a self-regulating reliability organization). The key recommendations include:

- Election in January 1999 of nine new independent board members who will succeed the current NERC board after reliability legislation is adopted in the United States and Canada.
- Binding agreements between NAERO and the affiliated regional reliability entities,
- Creation of three standing committees for security (operations), adequacy (planning), and market interface.

Thus, NERC is in the process converting itself into an organization that is broadly representative of the entire electricity industry (consumers and power marketers as well as suppliers), requires compliance with its policies and rules (which may require legislation in the United States, Canada, and Mexico), and is more of a top-down organization (and less dependent on the regional reliability councils).

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# Glossary of Key Terms

*Most of the following terms and definitions are taken from the August 1996* NERC Glossary of Terms. *Some are from the* Glossary of Terms *prepared by the National Council on Competition and the Electric Industry, and some were developed by the Task Force itself. And some were prepared for this report.*

**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.

**Aggregators** — Commercial entities that bring together collections of customer loads or generators to take advantage of economies of scale and diversity among the loads or generators being combined.

**Ancillary Services** — Interconnected Operations Services identified by the U.S. Federal Energy Regulatory Commission (Order No. 888 issued April 24, 1996) as necessary to effect a transfer of electricity between purchasing and selling entities and which a transmission provider must include in an open access transmission tariff. See also Interconnected Operations Services.

**Apparent Power** — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovolt-amperes (kVA) or megavolt-amperes (MVA).

**Automatic Generation Control (AGC)** — Equipment that automatically adjusts a Control Area's generation to maintain its interchange schedule plus its share of frequency regulation.

**Availability** — A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.

**Available Transfer Capability (ATC)** — A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

**Backup Power** — Power provided by contract to a customer when that customer's normal source of power is not available.

**Backup Supply Service** — The interconnected operations service that provides capacity and energy to a transmission customer, as needed, to replace the loss of its generation sources and to cover that portion of demand that exceeds the generation supply for more than a short time.

**Blackstart Capability** — The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

**Bulk-Power System** — The portion of an electric system that encompasses the generation resources, system control, and high-voltage transmission system.

**Capacity** — The rated continuous load-carrying ability, expressed in megawatts (MW), megavolt-amperes (MVA), or megavolt-amperes-reactive (MVAR) of generation, transmission, or other electrical equipment.

**Cascading** — The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

**Contingency** — The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

**Contract Path** — A specific contiguous electrical path from a point of receipt to a point of delivery for which transfer rights have been contracted.

**Control Area** — An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the Interconnection.

**Curtailment** — A reduction in the scheduled capacity or energy delivery.

**Deadband** — The frequency range within which the governor of a generator does not respond to changes in Interconnection frequency (typically ±0.036 Hz).

**Demand-Side Management** — Programs that affect customer use of electricity, both the timing (sometimes referred to as load management) and the amount (sometimes referred to as energy efficiency).

**Distributed Generation** — A distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local (substation level) peak loads and/or displacing the need to build additional (or upgrade) local distribution lines.

**Distribution System** — The portion of an electric system that "transports" electricity from the bulk-power system to retail customers, consisting primarily of low-voltage lines and transformers.

**Disturbance** — An unplanned event that produces an abnormal system condition.

**Dynamic Scheduling Service** — The interconnected operations service that provides the metering, telemetering, computer software, hardware, communications, engineering, and administration required to *electronically* move a transmission customer's generation or demand out of the control area to which it is physically connected and into a different control area.

**Electrical Energy** — The generation or use of electric power by a device over a period of time, expressed in kilowatthour (kWh), megawatthour (MWh), or gigawatthour (GWh).

**Electric System Losses** — Total electric energy losses in the electric system. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution elements.

**Electric Utility** — A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and is defined as a utility under the statutes and rules by which it is regulated. Types of Electric Utilities include investor-owned, cooperatively owned, and government-owned (Federal agency, crown corporation, State, provincials, municipals, and public power districts).

**Emergency** — Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system.

**Energy Imbalance Service** — The ancillary service that provides energy correction for any hourly mismatch between a transmission customer's energy supply and the demand served.

FACTS — Flexible alternating current transmission systems, the use of high-speed solid-state technologies to control transmission equipment to improve reliability and increase capacity.

**Federal Energy Regulatory Commission** — An independent Federal agency within the U.S. Department of Energy that, among other responsibilities, regulates the transmission and wholesale sales of electricity in interstate commerce.

**Frequency** — the rate, in cycles per second (or Hertz, Hz) at which voltage and current oscillate in electric-power systems. The reference frequency in the North American Interconnections is 60 Hz.

**Generator Governor** — The mechanical or electronic device that controls the power output of a generating unit in response to changes in Interconnection frequency.

**Grid** — A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points. Gridco is sometimes used to identify an independent company responsible for the operation of the grid.

**Independent System Operator (ISO)** — A neutral operator responsible for maintaining the generation-load balance of the system in real time. The ISO performs its function by monitoring and controlling the transmission system and some generating units to ensure that generation matches loads.

**Interchange** — Electric power or energy that flows from one entity to another.

**Interconnected Operations Services (IOS)** — Services that transmission providers may offer voluntarily to a transmission customer under Federal Energy Regulatory Commission Order No. 888 in addition to Ancillary Services. See also Ancillary Services.

**Interconnected System** — A system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

**Interconnection** — When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT, and Alaska. When not capitalized, the facilities that connect two systems or control areas. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a control area or system.

**Interface** — The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.

**Island** — A portion of a power system or several power systems that is electrically separated from the Interconnection due to the disconnection of transmission system elements.

**Load** — A consumer of electric energy; also the amount of power (sometimes called demand) consumed by a utility system, individual customer, or electrical device.

**Load Shedding** — The process of deliberately removing (either manually or automatically) preselected customer demand from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

**Location-Based Price** — Electricity pricing that reflects transmission losses and congestion as well as the local cost of generation at every point in the transmission system.

**Loss of Load Expectation (LOLE)** — 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.

**Margin** — The difference between net capacity resources and net internal demand. Margin is usually expressed in megawatts (MW) for operating reserves and as a percentage of either system load or installed generating capacity for planning reserves.

**Marketers** — Commercial entities that buy and sell electricity.

**N–1 Criterion** — A design rule intended to ensure that a power system will continue to function without interruption of service to customers even with the loss of any single component (such as a generator, transmission line, or substation). If there are N elements in the transmission system, it should continue to function with any set of N-1 elements.

**North American Electric Reliability Council (NERC)** — A not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of ten Regional Reliability Councils and one Affiliate whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The members of these Councils are from all segments of the electricity supply industry — investor-owned, Federal, rural electric cooperative, State/municipal, and provincial utilities, independent power producers, and power marketers. The NERC Regions are: East Central Area Reliability Coordination Agreement (ECAR); Electric Reliability Council of Texas (ERCOT); [Florida Reliability Coordinating Council (FRCC);] Mid-Atlantic Area Council (MAAC); Mid-America Interconnected Network (MAIN); Mid-Continent Area Power Pool (MAPP); Northeast Power Coordinating Council (NPCC); Southeastern Electric Reliability Council (SERC); Southwest Power Pool (SPP); Western Systems Coordinating Council (WSCC); and Alaskan Systems Coordination Council (ASCC, Affiliate).

**North American Electric Reliability Organization (NAERO)** — The planned successor to NERC.

**OASIS (Open-Access Same-Time Information System)** — An electronic posting system for transmission access data that allows all Transmission Customers to view the data simultaneously.

**Operating Reserve:**

> **Spinning Reserve Service** — The ancillary service that provides additional capacity from electricity generators that are online, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.
>
> **Supplemental Reserve Service** — The ancillary service that provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually 10 minutes.

**Pancaking** — The payment of charges for transmission services to more than one utility. One benefit of large, regional ISOs is the elimination of such multiple charges to move power across bulk-power systems.

**Parallel Path Flows** — The difference between the scheduled and actual power flow, assuming zero inadvertent interchange, on a given transmission path. Synonyms: Loop Flows, Unscheduled Power Flows, and Circulating Power Flows.

**Planning Reserve** — The difference between an electric utility's generating capacity (usually expressed in megawatts) and the anticipated peak load. Operating Reserve (see entry) is a subset of Planning Reserve.

**Power Pool** — An entity established to coordinate short-term operations to maintain system stability and achieve least-cost dispatch. The dispatch provides backup supplies, short-term excess sales, reactive power support, and spinning reserve. Historically, some of these services were provided on an unpriced basis as part of the members' utility franchise obligations. Coordinating short-term operations includes the aggregation and firming of power from various generators, arranging exchanges between generators, and establishing (or enforcing) the rules of conduct for wholesale transactions. The pool may own, manage and/or operate the transmission lines ("wires") or be an independent entity that manages the transactions between entities. Often, the power pool is not meant to provide transmission access and pricing, or settlement mechanisms if differences between contracted volumes among buyers and sellers exist.

**Ramp Rate** — The speed with which a generator can change its power output, expressed in megawatts per minute. Ramp rates for spinning reserve are often higher than those for regulation; positive and negative ramp rates can differ from each other.

**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. It also must supply the reactive losses on transmission facilities. 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).

**Reactive Supply and Voltage Control From Generating Sources Service** — The ancillary service that provides reactive supply through changes to generator reactive output to maintain transmission line voltage and facilitate electricity transfers.

**Real Power** — The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

**Real Power Loss Service** — The interconnected operations service that compensates for losses incurred by the Host Control Area(s) as a result of the interchange transaction for a transmission customer. Federal Energy Regulatory Commission's Order No. 888 requires that the transmission customer's service agreement with the Transmission Provider identify the entity responsible for supplying real power loss.

**Regional Regulatory Agency** — A government agency formed by several States and approved by the FERC to address regional transmission reliability issues. Such an entity would replace otherwise applicable State and local reviews and approvals.

**Regional Reliability Council** — One of 10 electric reliability councils that form the North American Electric Reliability Council (NERC).

**Regional Security Coordinator** — One of 23 NERC-established positions empowered to direct control-area operators, generators, and transmission-system users to take actions to maintain electric-system security.

**Regulation and Frequency Response Service** — The ancillary service that provides for following the moment-to-moment variations in the demand or supply in a control area and maintaining scheduled Interconnection frequency.

**Reliability** — The degree of performance of the elements of the bulk-power 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.

**Restoration Service** — The interconnected operations service that provides an offsite source of power to enable a host control area to restore its system and a transmission customer to start its generating units or restore service to its customers if local power is not available.

**RRO** — A regional reliability organization that would work with the SRRO on regional reliability issues.

**Schedule** — An agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the contracting parties and the control area(s) involved in the transaction.

**Scheduling, System Control, and Dispatch Service** — The ancillary service that provides for (a) scheduling, (b) confirming and implementing an interchange schedule with other control areas, including intermediary control areas providing transmission service, and (c) ensuring operational security during the interchange transaction.

**Seam** — refers to the interface between two adjacent electrical systems, such as control areas or ISOs. Because the rules and operating practices may differ across such entities, problems can arise at the seams.

**Security** — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

**Security Coordinator** — One of 23 entities established by NERC with the responsibility and authority to direct actions aimed at maintaining real-time security for a control area, group of control areas, NERC subregion, or NERC region.

**SRRO** — A self-regulating reliability organization. Creation of an SRRO likely requires Congressional action and subsequent FERC approval and oversight.

**Stability** — The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

**Synchronize** — The process of connecting two previously separated alternating current apparatuses after matching frequency, voltage, phase angles, and so forth (for example, paralleling a generator to the electric system).

**System** — An interconnected combination of generation, transmission, and distribution components comprising an electric utility, an electric utility and independent power producer(s) (IPP), or group of utilities and IPP(s).

**System Operator** — An individual at an electric system control center whose responsibility it is to monitor and control that electric system in real time.

**Thermal Limit** — The temperature-based power-transfer limit of a piece of electric equipment. This limit is a consequence of the electrical resistance of the piece of equipment, which causes the equipment to heat when power flows through it.

**Tieline** — A transmission line that interconnects two control areas or regions.

**TRANSCO** — An independent organization that owns and operates a regional transmission grid. A TRANSCO differs from an ISO in that an ISO does not own the transmission resources.

**Transmission** — An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

**Unbundled** — The separation (disaggregation) of the electric-supply system into its component parts (such as generation, system control, transmission, distribution, and customer service).

**Unit Commitment** — The process of determining which generators should be operated each day to meet the daily demand of the system.

**Volt-Amperes Reactive (VAR)** — The unit of measure of the power that maintains the constantly varying electric and magnetic fields associated with alternating-current circuits. See *Reactive Power.*

**Voltage** — The unit of measure of electric potential.

**Voltage Collapse** — An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage collapse may result in outage of system elements and may include interruption in service to customers.

**Voltage Control** — The control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

# Part II
# Approved Task Force Papers

# Appendix A
# Interim Report
# July 1997

# Secretary of Energy Advisory Board
# Task Force on Electric System Reliability

## Interim Report

July 24, 1997

### Background

This report makes recommendations regarding the security of the Nation's bulk power system consisting of generation, transmission, and control facilities.

Electric reliability can be divided into two areas: reliability of the distribution system and reliability of the bulk power system. Bulk power system outages affect large areas and can have significant regional and national implications. Further, the rules for assuring reliable operation of the bulk power system can have an effect on the transactions occurring on the system. Federal regulators have responsibility for economic regulation of electricity in interstate commerce, including wholesale transactions involving most of the Nation's generation and transmission facilities, within and across state borders. An issue introduced by competition in bulk power markets is the need to assure reliable system operations in a competitively neutral way. While everyone agrees that system reliability must be maintained as a feature of a competitive electric industry and must be under the direction of experienced, expert operators, not everyone agrees about how to resolve reliability issues in a manner that does not discriminate for or against certain participants in competitive bulk power markets.

While states have an interest in the performance of the bulk power system, state regulation has tended to focus on the distribution system. Outages on the distribution system generally have only localized effects and are frequently characterized as being related to end-use customer service, which is an area of state jurisdiction. States have traditionally also had regulatory responsibility for economic and planning approval for certain generation facilities, recovery of the costs of those facilities, and siting approval of both generation and transmission facilities within the state.

Bulk power system reliability has two components: adequacy and security. Adequacy implies that there are sufficient generation and transmission resources available to meet projected needs at all times, including peak conditions, plus reserves for contingencies. Security implies that the system will remain intact even after planned and unplanned outages or other equipment failures occur. Most view transmission adequacy and system security as "public goods" that benefit all buyers and sellers of electricity, and which exhibit monopoly characteristics. While the market will likely play a role in providing certain services that are needed for transmission adequacy and system security, these are the areas of greatest national interest from a reliability point of view and are the primary focus of this report.

In the past, the North American Electric Reliability Council (NERC), a self-regulating organization traditionally made up of electric utilities, and the ten regional reliability councils (hereinafter NERC and the councils are referred to as the Reliability Councils) have set operating and planning reserve requirements to assure generation adequacy. There are debates underway in various regions of the country with regard to the extent to which markets can and will be relied upon to assure generation adequacy, and whether there is a need for Reliability Councils to identify adequacy needs in the future. The Task Force is still considering the issues in this debate in its ongoing work.

Bulk power system reliability has historically been undertaken by the electricity industry, as opposed to the government, which has jurisdiction primarily through regulation of interstate transmission and wholesale electricity sales by the Federal Energy Regulatory Commission (FERC). The Department of Energy and the FERC also have some authority to order transmission, require interconnections, make reliability recommendations, regulate exports, and collect information. The industry, through the Reliability Councils, establishes reliability standards and monitors compliance. While these organizations have been effective in a world of vertically integrated electric utilities, there is concern today about the voluntary nature of their membership, their dominance by utilities, and the inability to mandate and enforce compliance among their members and other industry participants.

Further complicating reliability issues is incomplete jurisdictional authority over a system characterized historically by a strong tradition of voluntary and contract-based cooperation.

Similarly, the bulk power system is an international system. Collectively, the NERC, along with the Reliability Councils that include U.S., Canadian, and Mexican members, have a unique role in setting and monitoring international reliability standards. Close cooperation will be required between national, state, and provincial regulatory agencies that may be given authority for reliability oversight.

## Reliability Institutions

The bulk power system has become a highly integrated system over the past several decades. In the early days of the development of electric utility systems, power stations tended to be located near their local customers, with power distributed to the neighborhood. Over time, as plants became larger to capture economies of scale, they began to be located and operated at farther and farther distances from the loads they served, and had to be connected by transmission lines. Eventually, utilities recognized that they could achieve savings by interconnecting their transmission systems. As decades passed, a larger and larger set of generators, transmission facilities, and load centers were interconnected over increasingly large regions. These changes require increased coordination and planning among utilities to maintain reliability, a point which was starkly brought to the industry's attention in 1965 after a widespread outage blacked out the interconnected northeastern portion of the United States and Ontario, Canada.

To prevent such occurrences, the industry organized itself to better carry out reliability functions. Over time, the electric utility industry traditionally became vertically integrated, fully regulated, and composed of a limited number of entities who shared common systems and expectations for grid operation and use.

In this environment, three institutions evolved that are the focus of this report.

- NERC -- In 1968, the North American Electric Reliability Council was formed in response to the 1965 power outage in the Northeast. For nearly three decades, NERC's mission has been to promote electrical system reliability and thereby prevent further such occurrences. The NERC has been a voluntary, industry-constituted governing body that develops standards, guidelines, and criteria for assuring system security and evaluating system adequacy. The NERC has been funded by regional reliability councils, which adapt the rules to meet the needs of their regions. Through the work of its ten regional councils and one affiliate council, the NERC has largely succeeded in maintaining a high degree of transmission grid reliability throughout the country. Historically, the Reliability Councils have functioned without external enforcement powers, depending on voluntary compliance with standards and peer pressure.

- System Operators and Security Coordinators -- Today the country is served by approximately 150 separate control areas, each with its own system operator. The operators of these systems rely on communications with each other, access to essential system information, and real-time monitoring and control of certain facilities to maintain system reliability. When an emergency occurs on the system, the control area operator takes action -- both through communication and direct physical action -- to ensure the integrity and security of the system. These people take and direct others to take the actions necessary to "keep the lights on" and to protect against damage to the entire system in the event of emergencies. In addition to the individual control area operators, 22 Regional Security Coordinators coordinate within the regions and across the regional boundaries.

- FERC -- The Federal Energy Regulatory Commission is the Federal agency with jurisdiction over the bulk power market, including interstate transmission systems. As part of these responsibilities, the FERC implements policies to assure that the owners and operators of bulk power transmission facilities under the agency's jurisdiction provide nondiscriminatory service to all power suppliers in wholesale power markets. Historically, the FERC has not had to involve itself with regulating reliability functions. Increasingly, some parties are calling upon the FERC to begin to exercise its current authorities by addressing reliability issues that intersect with the commercial needs of the industry.

At the onset, we note that the electric industry is changing and, indeed, has *already* changed in several respects: wholesale electric markets are opening to competition under open access transmission tariffs; several states containing more than one-quarter of the Nation's population have decided to permit retail consumers to choose their suppliers (nearly all of the remaining states are studying retail competition); energy companies are merging and establishing innovative joint ventures; new competitors are entering markets; and new institutions are forming (e.g., independent system operators, power exchanges, and spot markets).

These trends indicate that in the future market forces will determine when, where, and what type of generation sources will be built and which energy trades will be transacted. Also, it is apparent that the Nation's transmission grid will be used by a larger number of entities for a larger quantity and variety of transactions. There are challenges regarding maintenance of traditional reliability levels in this new environment.

While the traditional reliability institutions and processes have served us well in the past, these institutions and processes need to be modified to assure that reliability occurs in a competitively neutral fashion, without favoring one or another set of market participants. To attempt to accommodate these new reliability issues that arise with competitive markets, today's existing reliability institutions have undertaken a number of new initiatives, including expanding their membership to include new market participants in addition to those longstanding members drawn from the electric industry. The Task Force welcomes these changes.

<u>Task Force Findings</u>

The Task Force has reached consensus on several key points:

1) Restructuring of the electric industry offers economic benefits to the Nation.

2) While the changes brought about by restructuring are complex, the reliability of the system need not be compromised provided appropriate steps are taken. Transmission grid reliability and an open, competitive market can be compatible.

3) The viability and vigor of the commercial market must not be unnecessarily restricted. The market forces being introduced now depend on fair and open access to the transmission grid.

4) Commercial markets should develop economic practices consistent with the ingenuity and mutual interest of the participants. However, grid reliability must be maintained through disciplined technical standards and practices.

5) Reliability standards must be clear, transparent, nondiscriminatory, enforceable, and enforced. Compliance must be mandatory for <u>all</u> entities using the bulk power system.

6) Regulatory oversight is necessary to ensure compliance with reliability policies and standards and to resolve disputes.

7) It is reasonable and practical to build on the experience and reliability standards developed by the Reliability Councils over the past 28 years. However, these standards as well as the Reliability Councils' own systems of governance must be modified to accommodate the complexities of the competitive market.

8) Grid reliability depends heavily on system operators who monitor and control the transmission grid in real-time. To assure competitive use of the grid, system operators must be independent from and have no commercial interests in electricity markets.

9) Bulk power systems are regional in nature and can and should be operated more reliably and efficiently when operators are coordinated over large areas.

10) The reasonable and necessary costs for maintaining the reliability system should be fully recoverable and equitably distributed.

11) Transmission grid reliability is a North American issue; the reliability relationships with Canada and Mexico must be preserved. Consultation with Canadian and Mexican governments is important for assuring reliability in the interconnected North American bulk power market.

## Task Force Recommendations

The Task Force recommends that:

1) The Reliability Councils expedite -- to the fullest extent possible and consistent with assuring sound results -- the modification of their governance structures to assure fairness and lack of domination by any single industry sector.

2) The FERC undertake a review of the Reliability Councils' existing policies and standards that affect the operation of an open electricity market and undertake a review of the Reliability Councils' organizational structures and governance. This proposed role for the FERC is important in order to make reliability standards enforceable and to assure that reliability standards and practices are not misused in ways that would be discriminatory in the competitive market. Given the considerable demands currently faced by the FERC, additional resources may be required by the agency in order to undertake this role.

3) Federal legislation is necessary to further clarify the authority and responsibility among the FERC and other entities for overseeing, setting, and enforcing reliability standards.

# Appendix B

# Maintaining Reliability Through Use of a Self-Regulation Organization

November 1997

Secretary of Energy Advisory Board
Task Force on Electric-System Reliability

# MAINTAINING BULK-POWER RELIABILITY THROUGH USE OF A SELF-REGULATING ORGANIZATION: POSITION PAPER

November 6, 1997

In its Interim Report, the Task Force recommended that federal legislation clarify the Federal Energy Regulatory Commission's (FERC) authority to approve and oversee the operations of an electric-reliability organization.[1] This paper provides Task Force recommendations concerning the relationship between the FERC and a single, international, self-regulating reliability organization (SRRO)[2], such as a significantly reformed North American Electric Reliability Council (NERC) with a representative membership and governance system, to assure reliability of the bulk-power system.[3]

## 1. BACKGROUND

Historically, NERC, the regional reliability councils, and individual utilities have managed reliability through a system of peer-reviewed standards coupled with voluntary cooperation and adherence to reliability rules. In that system, costs associated with maintaining reliability could be recovered through rates, and peer pressure and reciprocal treatment of costs were generally sufficient to keep utilities in compliance. Also, NERC, as an international organization, includes members from all countries sharing use of the interconnected transmission grid. Under this system, a set of effective reliability rules was developed and implemented.

The Task Force believes the system is clearly unsustainable in the increasingly decentralized and competitive U.S. electricity industry. Voluntary cooperation is unlikely to be sufficient because of the dramatic increase in the number of bulk-power transactions, the increased diversity of interests among participants, the growing unbundling (deintegration) of the electricity industry, the focus on price, and the lack of appropriate incentives for those entities contributing to reliability.

Most participants in and observers of the electricity industry agree that the voluntary system must be replaced with one that requires compliance with enforceable, non-discriminatory reliability rules applicable to all entities participating in the electricity market. This requires federal legislative authority.

1. The Task Force recognizes that the FERC presently has both the authority and the responsibility to deal with discriminatory practices by owners and operators of bulk-power transmission facilities.

2. Throughout this report we refer to the electric industry international reliability organization as the SRRO to distinguish it from other SROs.

3. The bulk-power system includes all facilities and control systems necessary for operating the interconnected transmission grids including: high-voltage transmission lines; substations; control centers; communications, data, and operations planning facilities; and those generating units necessary to maintain reliability.

NERC's Board of Trustees agreed in principle in January 1997 to require adherence to NERC rules and procedures. This new system attempts to feature: measurable performance standards, the requirement that all participants in bulk-power systems meet these standards, enforcement of these standards, and penalties for failure to comply with these standards. The detailed refinement of the standards and implementation of these principles is a work in progress.

Questions remain whether NERC has the authority to require industry participants to abide by the new rules and procedures in the absence of legislation. It is not clear whether the FERC has sufficient statutory authority to enforce NERC rules. The FERC has issued several orders requiring parties to abide by the NERC standards and parties have assented to the requirements. However, the use of FERC's conditioning authority to enforce NERC standards has not yet been challenged. Others question whether the FERC should enforce these rules in light of concerns over NERC's governance and decision-making procedures.

In response to these concerns, the Task Force suggests that the U.S. Congress adopt legislation to clarify such authorities and enable the FERC to approve a national self-regulating organization to establish electric reliability standards similar to the National Association of Security Dealers (NASD) in the securities industry. Under federal law, the Securities and Exchange Commission (SEC) has authority to delegate significant regulatory authority to a number of private, member-owned and operated organizations in the securities industry. The SEC has authorized several self regulating organizations (SROs) under the statutory framework.

The experience in the securities industry has been relatively successful in this regard. Self regulation under a legal framework established by Congress, and administered and enforced by a duly appointed federal agency, has certain advantages over government regulation in terms of lower costs to the taxpayer, administrative efficiency and technical expertise in developing and enforcing technical standards, and greater compliance by the regulated firms (because they helped develop the regulations). On the other hand, without careful oversight from the government, SROs might not fully consider the perspectives of the general public and focus too narrowly on the interests of the industry being regulated, especially on issues that involve policy elements rather than technical issues.

SROs have been challenged in the courts and have been found to be legal, but only if properly structured. For example, the SEC Act was found to be a constitutional delegation because:

- The SEC has the power, according to reasonably fixed statutory standards, to approve or disapprove rules; and
- The SEC must make an independent decision on violations and penalties.

## 2. SRRO APPLICATION TO NERC AND THE FERC

Federal legislation should grant more explicit statutory authority to the FERC to approve and oversee an electric industry SRRO having responsibility for bulk-power reliability standards.

As the industry organization currently responsible for electric reliability, most of the members of the Task Force believe that the NERC and its regional reliability councils will evolve into an entity that could fill the role of the SRRO. Most believe the NERC has already initiated many of the changes that will be required for it to be the SRRO. However, we note that this will not occur automatically. In order to qualify as the SRRO, a reformed NERC will have to meet all of the requirements of legislation and the FERC with respect to governance and processes.

The SRRO would provide the technical expertise on how best to maintain high levels of bulk-power reliability. The FERC would have regulatory oversight to ensure compliance with and ultimately resolve disputes over any SRRO mandatory reliability standards. The SRRO would produce mandatory standards applicable to all participants in the domestic and international bulk-power system. The FERC would either confirm SRRO mandatory standards or deny them and refer them back to the SRRO with comments requesting revision and resubmittal of the standards.[4]

The SRRO would develop measurable performance standards. These mandatory standards would replace the voluntary requirements that NERC has previously relied on. Importantly, however, NERC must expedite the development and implementation of measurable standards in an open process that includes full and fair representation of all stakeholders and market participants.[5] The Task Force recognizes that many non-utility participants have significant concerns about membership and representation and believe that NERC and the regional reliability councils must immediately open their membership to balanced representation of all stakeholders and market participants.

Legislation should provide for the following:

- FERC review and approval of a proposal for an electric industry SRRO;
- FERC implementation of mandatory reliability standards for the nation through rulemakings in accordance with the Administrative Procedures Act;
- FERC jurisdiction for reliability over the bulk-power system including those portions owned or operated by federal, cooperative, and municipal utilities and all other entities participating in the electricity market;
- FERC review and approval of all SRRO mandatory standards including specified incentives and penalties for compliance;

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4. Presumably, FERC's Canadian and Mexican counterparts would adopt similar reliability oversight roles.

5. Indeed, NERC currently posts proposed standards on its Internet site (www.nerc.com) and provides for a specified public-comment period. After the comment period is closed, the relevant NERC committee (Engineering or Operations) considers the comments and makes revisions to the proposed standard that the relevant committee believes appropriate. Ultimately, the NERC board is responsible for standards adoption. Most believe that neither the NERC committees nor the NERC board represent a full and fair representation of all stakeholders at this time. NERC recognizes this lack of representation and is trying to both develop and refine its processes for developing, reviewing, and adopting standards. NERC is also examining its membership and governance. The Task Force strongly encourages NERC to expedite these reforms pending legislation.

- FERC ability to require the SRRO to develop, modify, or replace standards when necessary;
- Mandatory application of reliability standards to all entities using or operating the bulk-power system;
- SRRO enforcement of mandatory standards, including imposition of penalties or fines, subject to FERC review;
- FERC authority to expedite or temporarily waive procedures when necessary to address an ongoing or imminent reliability problem;
- When requested by the SRRO or on its own initiative (e.g., in an emergency situation or stemming from a complaint), FERC review of any SRRO governance or process issues, standards, or SRRO enforcement action; and
- Sufficient resources for the FERC to administer its new responsibilities including the authority to levy necessary fees on the industry and access industry computer models, data and transmission experts.

When considering an application for the SRRO, the FERC would give notice of the application and provide an opportunity for public comment in accordance with the Administrative Procedures Act. Particular consideration would be given to SRRO governance, processes, and funding. The SRRO must assure a fair governance process that cannot be dominated by any single industry sector. The FERC would review the application to ensure that the SRRO would function in a manner consistent with the public interest and national reliability policy.

Likewise, when reviewing SRRO mandatory reliability standards, the FERC would issue a notice of proposed rulemaking based on the standard and provide an opportunity for public comment. FERC approval of a standard would require a finding that the standard was fairly developed, is cost effective, and is consistent with the public interest and national reliability policy.

In recognition of the international nature of the interconnected transmission grid, the Task Force has taken the position that mandatory electric reliability standards must be developed by the SRRO and approved by the FERC in accordance with the Administrative Procedures Act. Standard development needs to be done by a single entity that can represent all countries using the interconnected transmission grid. Also, SRRO development of the mandatory standards would avoid the imposition of federally developed standards on those portions of the interconnected transmission grid located in Canada and Mexico. Currently, the Canadian government and electric industry is represented in NERC and it will be necessary to include both Canadian and Mexican representation in the SRRO. The interests of the United States would be protected by enabling the FERC to require the SRRO to develop or modify standards as necessary. It would be incumbent upon the SRRO to develop mandatory standards that are acceptable to all three countries.

# Appendix C

# The Characteristics of the Independent System Operator

## March 1998

# Secretary of Energy Advisory Board
# Task Force on Electric System Reliability

## The Characteristics of the Independent System Operator

March 10, 1998

## I. Purposes of the Independent System Operator (ISO)

Many regions of the United States are developing ISOs. These developments spring in large part in response to the requirements of the Federal Energy Regulatory Commission (FERC) that all participants in competitive electric generation markets have non-discriminatory access to and use of transmission service, and as a way to maintain electric system reliability as competitive markets develop. The Task Force believes that ISOs are significant institutions to assure both electric system reliability and competitive generation markets.

Presumably, legitimate historical difference among regions of the country will lead to different ISO designs and approaches across the country. While the Task Force thinks that such variations are appropriate and in many cases desirable, there are nonetheless elements that are necessary to all ISOs in order to satisfy their common basic purposes. These common elements are the subject of this paper.

## II. Basic ISO Features

### A. *Description of Essential Functions*

The ISO has responsibility for the reliability functions in its area of operation and for assuring that all users have open and nondiscriminatory access to transmission services through its planning and operation of the bulk-power transmission system.

### B. *Attributes of ISOs*

#### 1. Functioning of the ISO

The ISO should conduct all of its activities in an impartial manner so that all users are treated equitably. The ISO should establish tariffs for use of the regional transmission system under its control. It should also be responsible for maintaining the reliability of the electrical system in its region in accordance with Self-Regulating Reliability Organization (SRRO)[1] criteria, guidelines and policies. The ISO should be responsible for coordination of all relevant activities with other entities (ISOs, security coordinators, control areas, Regional Transmission Groups (RTGs), etc.) directly connected to or affecting it substantially.

[1] Refer to the Task Force SRRO report Maintaining Bulk-Power Reliability Through Use of a Self-Regulating Organization issued on November 6, 1997.

2. **The ISO should be an operating entity, not a standards-setting organization.**

   The SRRO is the organization that should set the criteria, principles, standards and rules for the secure operation of the electric system. The ISO should not duplicate the function of the SRRO; instead, the ISO should implement and adhere to the rules and standards of the SRRO. The ISO might however, in some instances, establish additional operating procedures that are specific to its area.

3. **The ISO should direct the actions of all users[2] of its transmission network as necessary to perform its functions.**

   Like an orchestra conductor, the ISO should coordinate the reliability and transmission related activities of all users of the bulk power system in its area. All transmission services users must commit to following the rules and procedures, etc. of the ISO as a condition of receiving service.

4. **Scope/Jurisdiction of the ISO**

   The ISO should be a federally regulated independent system operator and planner of regional transmission. It should be under FERC jurisdiction for rates, terms and conditions of service. The ISO planning and operations are established to meet the needs of all the users in the region it serves, cutting across state boundaries, if applicable.

   Although the ISO will develop and approve regional transmission plans, it should be the responsibility of transmission owners to obtain all necessary approvals for the siting and/or construction of new or modified facilities.[3]

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[2] Throughout this paper the term "all users" includes all utilities' native load customers and the entities serving them including the transmission owners.

[3] The construction of new transmission facilities intended to meet regional needs faces significant barriers because there is no established authority for the siting of transmission facilities across state boundaries. Authority over siting and permitting of new transmission facilities remains with the states, and these siting authorities and policies differ widely among states and are necessarily focused on local needs.

One barrier to construction of regional transmission projects is a concern at the state level over undue rate impact on local ratepayers caused by a regional transmission project. This concern can be addressed by the establishment of ISO tariffs and the unbundling of transmission rates from retail rates. Through its tariffs, the ISO will be able to allocate the cost of new transmission to those benefiting from that facility. However, retail rate unbundling, although convenient, is not essential to the establishment of effective ISOs. (Wholesale rate unbundling is already required by the FERC for transmission facilities under its jurisdiction.) The Task Force anticipates that it will address issues related to incentives in a separate paper.

5. **The ISO should be supported by the users of the bulk-power system.** The ISO should establish and charge rates for its services, pursuant to tariffs approved by the FERC[4].

## C. *Reliability-Related Activities of the ISO: (Security and Adequacy)*

### 1. System Operations and Coordination

a) Implement SRRO security procedures and practices.

b) Perform system security monitoring functions, where system (grid) security is the ability of the electric transmission system to respond to disturbances without cascading or widespread failures.

c) Redispatch generation as necessary to maintain system reliability, including taking all necessary emergency actions to maintain the security of the system in normal and abnormal operating conditions. All generation within the ISO region should be subject to the redispatch authority of the ISO while retaining, where possible, the opportunity for market participants to participate in the process. Generation owners should be compensated for the costs of redispatch.

d) Enforce the penalties for non-compliance with SRRO's[5] and ISO's own rules and directives.

### 2. Regional Transmission Planning and Construction

a) The ISO in coordination with the transmission owners and other market participants should carry out reliability studies and planning activities to assure the adequacy of the transmission system following SRRO standards.

b) The ISO should publish data, studies and plans relating to the adequacy of the transmission system. Data might include location-specific congestion prices, and planning studies that identify options for actions that might be taken to remedy reliability problems on the grid and cost data for some of these actions.

c) The ISO should establish criteria to identify projects that could properly be considered regional from those that are local with very little or no regional impact, and to allocate costs per its tariff.

d) Users should express their willingness to pay for or assist in paying for transmission expansion projects by making firm service requests. Likewise, users should pay for the construction of directly assignable facilities or facilities they build and own.

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[4] In this paper the Task Force understands that transmission will remain a regulated monopoly with cost-based, non-discriminatory, and just and reasonable tariffs.

[5] For a discussion on SRROs refer to the Task Force paper on SRROs, referenced above. In that document the task force concluded that federal legislation might be required to enforce penalties for non-compliance.

e) The projected costs of transmission expansions should serve as an economic signal for competitive investments in other resources, such as distributed generation or demand side programs that can, in some circumstances, provide more economic alternatives for reliable service.

f) In regions that have established regional transmission groups (RTGs)[6], the ISO should participate in RTG processes.

g) Transmission owners in the ISO region should commit to support the construction requirements of the ISO regional transmission plan. The ISO should provide a reasonable assurance of an opportunity to recover cost including a fair return on investments.

## D. *Market-Related Activities of the ISO*

1. The ISO should be a market enabler with no commercial interest in the competitive portions of the generation market.

2. The ISO's activities must be carried out according to transparent, understandable rules and protocols, under policies established by the ISO Board and subject to after-the fact dispute resolution mechanisms. The ISO must take all actions in a manner that is not preferential to the commercial interests of particular users being affected by the ISO action.

3. Regional transmission planning (whether conducted or coordinated by the ISO, or whether carried out by some other regional planning body with participation by the ISO) should take into account the reasonably anticipated needs of all users.

4. The ISO should perform the following operational functions and services to enable the competitive generation market.

   a) Determine Available Transmission Capacity (ATC) for all "paths" of interest within the ISO region. There is much judgment in the determination of available transmission capacity. Ultimately it involves a balance between the obligation to provide service as requested by users and the need to operate at all times within the thermal and stability limits of the electric system. The independence and commercial objectivity of the ISO operators should assure that all users are equitably treated as this balance is struck.

   b) Receive and process all requests for transmission service within and through the ISO region from all users, including owners of transmission.

   c) Develop, file and administer ISO-wide tariffs.

6 Regional transmission groups have been approved by the FERC for the main purpose of performing regional transmission planning.

d) Schedule all transactions it has approved. Approve or deny transmission service requests in accordance with the transmission tariffs and the ISO's procedures.

e) Treat all service requests in a nondiscriminatory manner under the tariffs approved by FERC.

f) Operate or participate in an information OASIS. There should be a single OASIS for all services provided by the ISO.

g) Establish a clear ranking of the transmission rights of all users on the ISO transmission system.

h) Facilitate trading of transmission rights on its grid among users.

I) Manage transmission congestion in accordance with ISO rules and procedures. Establish and implement procedures for generation redispatch as necessary to maintain system security and to expand transmission capacity to meet service requests. Establish and implement clear and fair rules to compensate generation owners for redispatch costs and to allocate the cost of redispatch to the appropriate users.

j) Establish efficient pricing for and distribution of the costs of congestion subject to FERC review and approval.

k) Assure the provision of ancillary services required to support all scheduled delivery transactions.

### E. *ISO Governance*

1. The governance structure must assure that the ISO meets its essential purposes as stated above. It should be established to reflect the reasonable needs of all market participants.

2. There are various ways to arrange the ISO governance, most notably through a board whose members include no market participants, or individuals with financial interests in any market participant. Alternatively, the ISO could be governed by a board which balances the interests of all market participants but in which no set of market participants may dominate decision making[7]. Either approach may be workable as long as it establishes independence from control by any set of market participants in either the ability to pass or block the passage of measures.

### F. *ISO Size and Participation*

1. **ISOs should be as large as practical.**
From a practical point of view, the size and particular features of an ISO may be limited by historical and regional differences as well as by the capabilities of the technology used by the ISO to perform its functions.

[7] There is concern that a representative board may become too large to be effective.

Such factors include the existence of power pools and the establishment of ISOs to serve all users of the transmission system within the area of the pools. There may also be geographic, regulatory, political or economic considerations that dictate boundaries between ISOs[8]. However in order to bring market efficiency to a region an ISO should cover an area as large possible. A large ISO will have significant benefits, including:

a) Access to real time information on an area large enough to permit identification of the far-flung impacts that local activities can have on the network. Consequently, a large ISO will be able to identify and address reliability issues most effectively.

b) There will be fewer "boundary problems". A large ISO will internalize much of the loop flow caused by transactions, thus overcoming many of the limitations and conflicts inherent in the "contract path" method of allocating transmission capacity.

c) Having a single transmission service provider with a single set of tariffs will facilitate transmission access across a larger portion of the network and consequently will improve market efficiencies and promote greater competition.

d) ISO tariffs, whether a "postage stamp" or a "license plate"[9], will eliminate "pancaking" of transmission rates allowing a greater range of economic energy trades across the network

2. **Federal Power Marketing Administrations (PMAs), public power agencies and rural electric cooperatives should participate in ISOs.**

Federal legislation may be necessary to allow PMAs, public power agencies and rural electric cooperatives to cede operational control of their transmission facilities to ISOs. Recent rulings by the U.S. Department of the Treasury indicate that public power agencies can participate in ISOs without losing their tax-exempt status. Federal legislation or a permanent Treasury Department policy may be needed to allow public power agencies and rural electric cooperatives to participate in the formation of ISOs.

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8 The Task Force concludes that, in general, single state ISOs are impractical and, in fact, may be discriminatory and should be discouraged.

9 A "Postage Stamp" rate allows all users in a region to pay the same price to use the region's transmission network for transmission across the region, regardless of the location of the generator or the user. A "license plate" tariff blends zonal prices (the zone in which the load is located) with grid wide access at no additional costs except for congestion costs. It allows any user located in a zone to pay the same rate for transmission from any generating source within the ISO region including those located outside of the zone. It resolves concerns about the cost shifts that would occur between customers of individual transmission owners within the ISO due to significant differences in the embedded costs of the different transmission zones within the ISO. By contrast, a "pancaked rate" is one that charges a user a separate rate for transmitting across each transmission-owning company's service area existing along a path between the generator and the user.

### G. *ISO Employees and Standard of Conduct*

1. Neither the ISO nor its employees may hold ownership in, represent, or be employed by any entity with a financial interest in the commercial competitive electricity markets served by the ISO nor in any of the entities participating in the electric market in the region served or affected by the ISO.

2. A Standard of Conduct should be developed to guide all of the actions of ISO employees in relation to market participants.

3. The Board of Directors should establish appropriate incentives to ISO employees for exemplary performance of ISO activities.

## III. ISO coordination with other entities

### A. *Relationships between Control Areas and ISOs.*

The present day control area operators are responsible for many functions; among them is the instantaneous balancing of generation and load within their control areas. The retention of existing control areas within the ISO, or their merger into fewer or even a single control area is not necessarily a prerequisite to enabling the ISO to carry out its duties, so long as:

- The boundaries between control areas do not give rise to transmission rate pancaking; and
- Control area operations are subject to the undisputed authority of the ISO in matters related to reliability of the bulk power system and the provision of transmission service pursuant to the ISO tariff. On such matters the ISO should monitor the performance of each control area and issue orders for corrective actions as necessary.

### B. *Coordination Between and Among ISOs, Coordination between ISOs and non-ISO entities and Monitoring of ISOs' Performance*

Given the inevitability of boundaries between multiple adjacent ISOs as well as between ISOs and non-ISO areas it will be essential that:

- There be much coordination between adjacent ISOs to address reliability as well as market issues, this coordination being an essential function of ISOs; and
- There be much coordination between ISOs and any adjacent non-ISO entities such as control areas, security coordinators, independent transmission companies, foreign utilities, etc.
- There be some entity responsible for monitoring and rating ISO performance.[10]

[10] In its SRRO report, the Task Force concluded that the SRRO should perform this function.

# IV. Transmission Ownership and Compensation

The establishment of ISOs should effectively decouple the use of transmission from any advantage related to its ownership, since transmission owners will retain no preferential treatment or market knowledge. It is possible that the evolution of the electric industry will result in the formation of companies involved solely in the business of owning and operating transmission systems. If these companies are large enough and not controlled by any of the market participants, they could perform the ISO functions[11].

## *A. Compensation*

The ISO should assure the right of transmission owners to recover from the ISO the cost of ownership, maintenance and operation of the transmission facilities they own. (The ISO has the right and duty to charge and collect rates from users, pursuant to an FERC-approved tariff.)

## *B. Ownership*

Transmission owners should retain:

1. Ownership of transmission facilities;
2. Obligation to perform routine hands-on maintenance (subject to ISO concurrence on scheduling) and operations (subject to ISO direction) of their transmission equipment;
3. Obligation to deliver and to build to provide service as defined in the ISO tariff;
4. Opportunity to obtain through ISO tariffs an adequate compensation for their work and a fair return of and on their investments; and
5. Obligation to deliver and to build in accordance with the ISO (or RTG) transmission plan, and subject to all necessary regulatory approvals.

[11] If approved by FERC.

## V. Dispute Resolution Process

It is essential that all market participants have access to an effective dispute resolution process to resolve promptly and equitably the many issues that are likely to arise from ISO activities. Presuming that the SRRO (and regulatory authorities, by extension) will also be committed to the establishment of dispute resolution processes, it would be very advantageous if processes were coordinated in order to resolve disputes in a timely manner and to avoid delays, game playing and confusion.

Ultimately the parties must have the right to appeal to both the FERC and the courts to defend their rights.

**Table: Roles, Functions and Relationships of Various Institutions with Respect to ISOs**

| Organization | Purpose | Function | Skills | Institutional Governance |
|---|---|---|---|---|
| National Regulator (FERC, Canadian, Mexican) | Provide government oversight and support for the development and enforcement of SRRO reliability standards and provide for the recovery of appropriate transmission and reliability costs. | Review and approve SRRO processes and standards to ensure that standards are fairly developed, cost effective, and consistent with the public interest and national reliability policy. Approve transmission tariffs that provide for a fair distribution of transmission and reliability costs. | Regulatory including the ability to solicit public comments, conduct public hearings, resolve disputes regarding enforcement of standards, and provide a mechanism for appeal and review. | Appointed by (US, Canadian and Mexican) governments |
| SRRO (e.g., NAERO & Regional Reliability Organizations) | Electric industry Self-Regulating Reliability Organization to develop, monitor and enforce international and regional standards that maintain high levels of bulk-power reliability economically and with minimal impact on electricity markets. | Develop (in a public forum) reliability standards, protocols and procedures that are applicable to all users of the interconnected electric grid. Provide regional flexibility in implementing, monitoring and enforcing standards. | Technical committees with specific technical expertise on electric system operations and planning. Economic expertise, including knowledge of how electricity markets will interact with reliability standards. | Independent policy-making board composed either of non-market participants, or of a combination of a majority of market participants and a minority of balanced market participants. Technical committees must have broad industry representation. |
| State/Provincial Regulators & RRAs | Ensure that state and provincial interests are addressed in the creation of ISOs and the siting of transmission facilities. Regional regulatory agencies (RRAs) may be formed to ensure that regional reliability benefits are appropriately considered in siting decisions. | Review and approve, when appropriate, permits for the construction of transmission improvements for maintaining bulk-power reliability. Review should include the consideration of non-transmission alternatives. | Regulatory skills, including the ability to solicit public comments and hold hearings on proposed transmission construction projects. Ability to balance resource impacts, economic costs, and reliability benefits. | Appointed by State and Provincial governments. In the case of RRAs, states would enter into agreements to delegate siting authority to the RRA. |
| ISO | Operate the regional transmission network. Assure reliable operation in accordance with SRRO standards and comparable access in accordance with FERC tariffs and policies (for the US participants). | A system operator and system planner. An implementer of standards and guides produced by the SRRO. Enforcer of the rules, including penalties. Regional Security Monitor | Operating and Planning staffs will need to be highly skilled in system operations and planning. The Board requires members with corporate board-level skills, capabilities and expertise. | Board Of Directors that is either representative of all participants in a way where no set of participants can control the Board, or independent from participants. Operations will be conducted by the skilled, professional, operating staff. |

# Appendix D

# Ancillary Services and Bulk-Power Reliability

May 1998

# ANCILLARY SERVICES AND BULK-POWER RELIABILITY

A Position Paper of the
Electric-System Reliability Task Force
Secretary of Energy Advisory Board
May 12, 1998

## 1. BACKGROUND

This paper provides background on ancillary services[1] and Task Force recommendations to ensure that these services are available, produced, and managed so as to maintain bulk-power reliability. Ancillary services are critical to the reliable operation of the bulk-power system. They are necessary to assure stability of the grid and to prevent cascading outages in the event of an unplanned outage of a generating unit or transmission facility. Some ancillary services (e.g. system blackstart capability) are necessary to recover from an outage.

Ancillary services are those functions performed by the equipment and people that generate, control, and transmit electricity in support of the basic services of generating capacity, energy supply, and power delivery. Historically, these services have been provided by vertically integrated utilities as part of their bundled electricity product. Increasingly, as the industry is being restructured, they are being supplied as separate services in a system that includes unbundled generation, transmission, and system control. The Federal Energy Regulatory Commission (FERC) defined such services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." As discussed below, these ancillary services are only rarely optional.

### Twelve Key Services

FERC's April 1996 Order 888 specifies six services that transmission providers are required to offer (Table 1). The Interconnected Operations Services Working Group (facilitated by the North American Electric Reliability Council and the Electric Power Research Institute) identified an additional six services, some of which are essential for reliability (e.g., system black start and

1. Readers interested in additional details on the definitions, metrics, and requirements for these services should see: E. Hirst and B. Kirby 1998, *Unbundling Generation and Transmission Services for Competitive Electricity Markets: Examining Ancillary Services*, NRRI 98-05, prepared for the National Regulatory Research Institute, Columbus, OH, January; and Interconnected Operations Services Working Group 1997, *Defining Interconnected Operations Services Under Open Access*, EPRI TR-108097, Electric Power Research Institute, Palo Alto, CA, May.

network stability services).[2] FERC discussed some of these additional services in Order 888 but did not require transmission providers to offer them. As the electricity industry evolves, further unbundling or rebundling of services may be desirable.

As shown in Table 1, most ancillary services are provided by generating units, some are provided by transmission-system equipment, and some are provided by both generators and transmission equipment. Almost all services must be under the control of the system operator. Although FERC requires transmission providers to offer six services to transmission customers, five of the six are produced by generating units not by transmission equipment.

**Functions**

Of the 12 services shown in Table 1, six are required for normal operation of bulk-power systems, including system control, voltage control, regulation, energy imbalance, load following, and loss replacement. These services ensure that voltages and equipment loadings are maintained within appropriate limits and that the necessary generation/load (production/consumption) balance is maintained at all times.

Five services are used to prevent minor problems from cascading into major outages. These services include spinning reserve, supplemental reserve, and network stability as well as system control and voltage control (both of which are necessary for normal operations).

Finally, eight services are required to safely and promptly restore systems after a major disturbance occurs. These services are system blackstart as well as the previously cited services of system control, voltage control, network stability, regulation, the two operating reserves, and load following.

Clearly, these ancillary services perform essential functions in maintaining the integrity of the transmission system, in preventing small problems from becoming major problems, and in resolving those rare, but serious major problems. Indeed, only three services serve no reliability function: energy imbalance, backup supply, and dynamic scheduling. These three services are needed only for commercial purposes.

2. Regardless of the number, names, and definitions of these services, the physics of electric-power networks require that they be provided at the right times and places and in the correct quantities.

**Table 1. Key ancillary services and their definitions**

| Service | Description | Time scale |
|---|---|---|
| | **Services FERC requires transmission providers to offer and customers to take from the transmission provider** | |
| System control | The control-area operator functions that schedule generation and transactions before the fact and that control some generation in real-time to maintain generation/load balance; Interconnected Operations Services Working Group definition more restricted, with a focus on reliability, not commercial, activities, including generation/load balance, transmission security, and emergency preparedness | Seconds to hours |
| Reactive supply and voltage control from generation | The injection or absorption of reactive power from generators to maintain transmission-system voltages within required ranges | Seconds to hours |
| | **Services FERC requires transmission providers to offer but which customers can take from the transmission provider, buy from third parties, or self-provide** [a] | |
| Regulation | The use of generation equipped with governors and automatic-generation control (AGC) to maintain minute-to-minute generation/load balance within the control area to meet NERC control-performance standards | ~1 minute |
| Operating reserve - spinning | The provision of generating capacity (usually with governors and AGC) that is synchronized to the grid and is unloaded that can respond immediately to correct for generation/load imbalances caused by generation and transmission outages and that is fully available within 10 minutes | Seconds to <10 minutes |
| Operating reserve - supplemental | The provision of generating capacity and curtailable load used to correct for generation/load imbalances caused by generation and transmission outages and that is fully available within 10 minutes[b] | <10 minutes |
| Energy imbalance | The use of generation to correct for hourly mismatches between actual and scheduled transactions between suppliers and their customers | Hourly |
| | **Services FERC does not require transmission providers to offer** | |
| Load following | The use of generation to meet the hour-to-hour and daily variations in system load | 10 minutes to hours |
| Backup supply | Generating capacity that can be made fully available within one hour; used to back up operating reserves and for commercial purposes | 30 to 60 minutes |
| Real-power-loss replacement | The use of generation to compensate for the transmission-system losses from generators to loads | seconds to hour |
| Dynamic scheduling | Real-time metering, telemetering, and computer software and hardware to electronically transfer some or all of a generator's output or a customer's load from one control area to another | Seconds |
| System-black-start capability | The ability of a generating unit to go from a shutdown condition to an operating condition without assistance from the electrical grid and then to energize the grid to help other units start after a blackout occurs | When outages occur |
| Network-stability services | Maintenance and use of special equipment (e.g., power-system stabilizers and dynamic-braking resistors) to maintain a secure transmission system | Cycles |

[a] These four services are required only to serve load within the control area, not for wheeling through.
[b] Unlike spinning reserve, supplemental reserve is not required to begin responding immediately.

## Monopoly and Market Approaches to Pricing and Provision

Because most of these 12 services are provided by generators, it should be possible to create competitive markets for them. Such services include regulation, load following, spinning reserve, supplemental reserve, backup supply, energy imbalance, and loss replacement. Markets for these seven services are likely to be competitive where the markets for the basic energy commodity are workably competitive. In such cases, markets, rather than government regulators, will determine the suppliers of and set the prices for these services.

It may be possible to establish competitive markets for three additional services, voltage control, blackstart capability, and network stability. The opportunities to create markets for these three services may be limited because of the locational requirements of these services. For example, the injection and absorption of reactive power must occur close to where voltages must be maintained within required limits. In other words, transmission grids can transport reactive power over much shorter distances than they can transport real power.

Because generators provide both the energy commodity and several ancillary services, there will be strong interactions between and among the markets for energy and these services. To ensure that reliability can be maintained, the rules governing provision of and payment for ancillary services must discourage gaming. Failure to establish suitable structures and rules for these markets will complicate the provision of ancillary services and therefore electricity markets.

The cost-causation factors used to price these services to customers may vary from service to service and with time (e.g. from hour to hour). As examples, these costs might be related to and therefore collected on the basis of energy consumption, peak demand, short-term (minute-to-minute) volatility of load, and so on.

Finally, creation of competitive markets will offer opportunities for greater customer participation in these markets. Historically, customer options were limited to a few choices, such as interruptible rates and direct load control. Greater use of real-time pricing plus customer bids to supply operating reserves may increase system reliability at lower costs than would occur through reliance on traditional supply options alone.

## System Operator Role

Regardless of whether markets or regulators determine the prices of some ancillary services, the system operator will remain the primary authority on how much of each service is required each hour and, for some services, the locations at which these services must be provided to the grid.[3]

3. The control-area operator might be a traditional vertically integrated utility, an independent system operator (ISO), or some other entity. To the extent that the system operator is independent of commercial interests, its decisions and actions are more likely to be trusted and honored than if the system operator has commercial interests in electricity markets.

The system operator will also determine how to select service providers, e.g., through competitive bidding, long-term bilateral contracts, or FERC-approved tariffs. The system operator, consistent with national reliability requirements, will establish (1) a priori (e.g., day ahead) requirements for each service and (2) real-time management of the resources that provide these services. Clear specifications will ensure that service providers and consumers know what to expect, how performance will be measured, and who will pay whom for what.

By definition, the system operator is the only entity that can provide the system control and scheduling service. However, almost by definition, the system operator cannot provide any of the other services. To the extent that the system operator is *independent* of the owners of generation and transmission, it will not be able to physically provide these ancillary services.

However, the system operator may need to control the provision of many of these services. The role of the system operator is crucial for three reasons. First, the system operator is the only entity that has enough real-time information to know how much of each service is required and any locational restrictions on the provision of these services. Second, it is much more cost effective to provide many of the services (e.g., regulation and operating reserves) for the aggregate load than for each load separately. Third, it would be very difficult to provide some services, such as system control and voltage control, to individual customers. Indeed, it is desirable to provide the services to individual customers for only a few services, including backup supply, energy imbalance, dynamic scheduling, and perhaps load following and losses.

With respect to system services, the system operator—and only the system operator—knows what the regulation requirements are for the control area from second to second. The operator's knowledge of area-control error (ACE), calculated every two to four seconds, is the basis for its decisions on whether and how to use the regulating margin at its disposal. Thus, although the generators that provide this service may be neither owned nor operated by the system operator, their provision of the regulation service is controlled by the AGC signals that the system operator sends to each generating unit that is providing the service.

In a similar fashion, only the system operator, based on its knowledge of power flows and possible contingencies, can set the voltage schedules and reactive-power reserves throughout the transmission grid. Therefore, voltage schedules and the resulting reactive-power injection and absorption must be under the control of the system operator.

Analogous situations apply to the operating-reserve services, energy imbalance, black-start capability, and network-stability services. For all of these services, the system operator is the only entity with sufficient and timely information to decide how much of each service is required. In addition, system provision of the service, rather than customer provision, provides economies of scale. That is, fewer resources are required to provide a given level of service to an aggregation of loads than to the sum of the services provided to individual loads.

The operator does not need to control the provision of backup supply or dynamic scheduling. However, it needs up-to-date (i.e., once every several seconds for dynamic scheduling) information on the status of these services and their provision. This information requirement is a consequence of the system operator's responsibility to maintain generation/load balance within the control area.

The operator does need to control the real-time provision of losses. But the operator does not need to choose the generators that provide for loss compensation.

## 2. TASK FORCE RECOMMENDATIONS

Because ancillary services are integral to bulk-power reliability, the Task Force on Electric-System Reliability offers the following suggestions:

1) The Self-Regulating Reliability Organization (SRRO), subject to FERC jurisdiction, should develop and implement clear and consistent national definitions of ancillary services. These definitions should include methods to measure the capability and the delivery of each service as well as penalties for noncompliance with these performance metrics. These definitions should be sufficiently flexible to encourage innovative ways to provide the service (e.g., automatic control of some customer loads could serve as alternatives to generation for spinning reserve). Periodically, the FERC should consider additions, deletions, and modifications to the six ancillary services included in Order 888. This expansion could apply to services such as system blackstart, network stability, load following, and perhaps others.

2) FERC and the system operators should promote the creation of competitive markets for ancillary services wherever feasible. Competitive markets offer the possibility of increased reliability at lower cost, as well as fewer regulatory controversies over embedded-cost pricing. When it is demonstrated that competitive markets exist, FERC's price-setting role could be minimal. Where locational requirements are strict and ancillary service providers are limited, competitive markets may not be feasible. In such cases, FERC should continue to regulate the provision and pricing of these services.

3) FERC and the system operators should ensure that all bulk-power market participants provide (or secure from third parties) their fair share of ancillary services, especially those required for bulk-power reliability. Where costs can be assigned to specific customers (e.g., for backup supply or dynamic scheduling), those customers should pay the full costs.

4) FERC and the system operators should ensure that the providers of ancillary services have opportunity to receive fair compensation for the prudently incurred costs to produce those services not provided through competitive markets. FERC's role in setting prices will

likely be a function of the independence of the system operator from commercial interests and the strengths of competitive markets for these ancillary services. Where competitive markets exist, FERC jurisdictional utilities should no longer be obligated to offer these services at embedded-cost prices.

5) FERC and the SRRO should ensure that system operators have sufficient authority to compel generation and transmission owners to supply (and customers to pay for) the amounts and characteristics of each service determined by the system operators to be required for reliability and to support commercial transactions. The system operator must be the final authority on how much of a service is required and, in some cases, the locations at which that service must be provided to the grid. The system operator need have no authority over the prices of most services. To the extent that system operators have no commercial interests in electricity markets, FERC's oversight could likely be reduced.

## 3. CONCLUSIONS

The U.S. electricity industry is currently in the midst of a major transition from one dominated by large vertically integrated utilities that sell a bundled electricity service to retail-monopoly-franchise customers to one that is dominated by competitive generating firms and regulated transmission and distribution entities. Because the ancillary services discussed here are essential for maintaining bulk-power reliability, the DOE Task Force is concerned that their availability, production, and deployment be maintained. Substantial progress has been made during the past few years to identify and define these critical services. However, much remains to be done to develop a clear understanding and workable definitions of these services, as well as appropriate pricing rules for them.

# Appendix E

# Technical Issues in Transmission System Reliability

May 1998

# Technical Issues in Transmission System Reliability

A Position Paper of the
Electric System Reliability Task Force
Secretary of Energy Advisory Board
May 12, 1998

## Section 1 -- Introduction

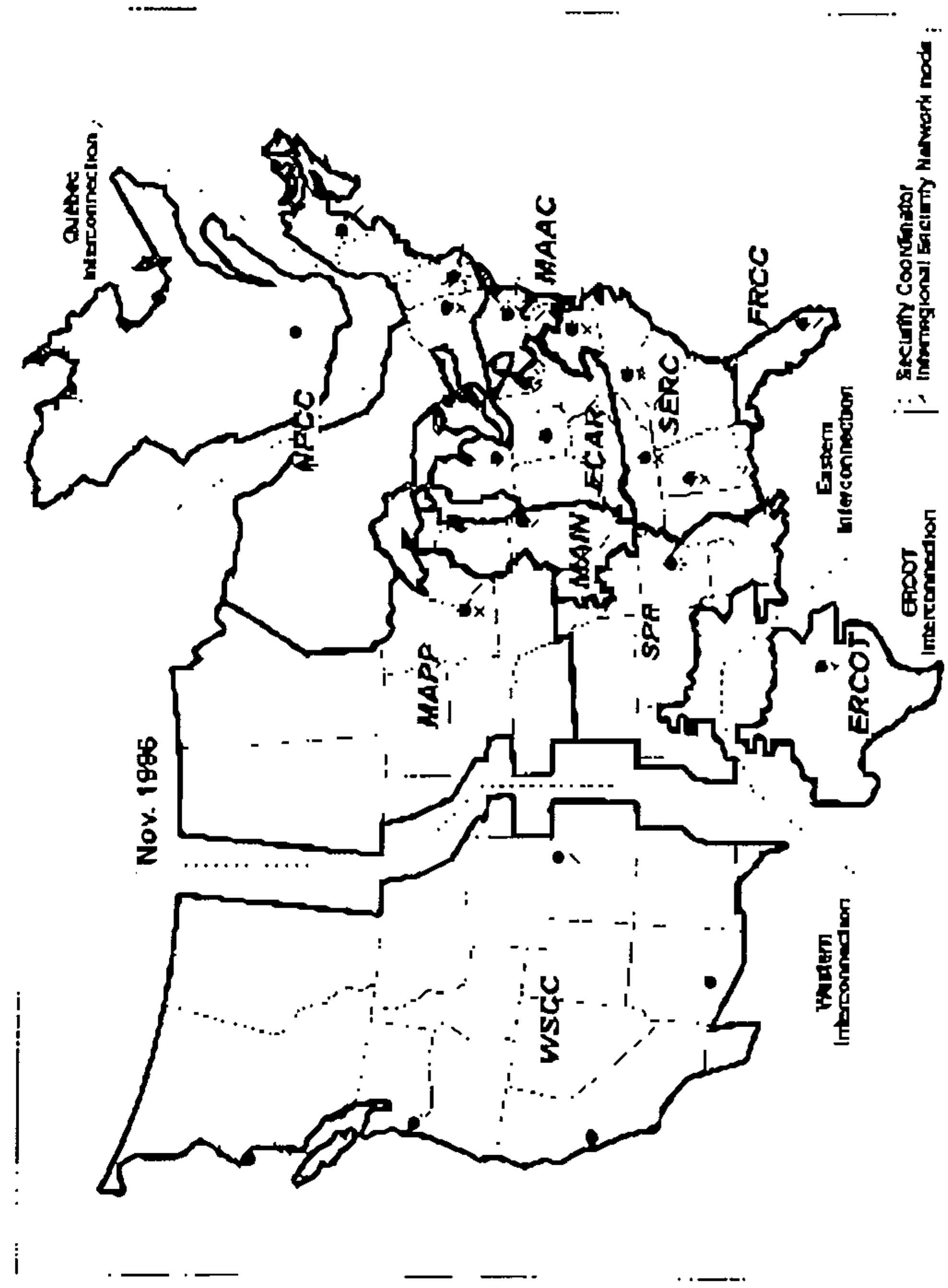
The vast, highly interconnected North American power system has been called the "greatest machine ever created." Generators separated by thousands of miles must rotate together with split-cycle synchronism, and the flow of power over thousands of transmission lines must be coordinated over large regions of the country. Now, as profound changes sweep through the U.S. electric power industry, this complex machine is being required to work harder than ever before and perform in ways for which it was not originally designed. As a consequence, challenges face the industry on how to maintain power system reliability during this time of transition.

### Structure of the Grid

The North American power grid comprises four major synchronous interconnections -- western, eastern, Texas, and Quebec -- which are further divided into ten Regional Reliability Councils (RRC). Each RRC has primary responsibility for maintaining grid reliability in its region, which involves coordinating the activities of numerous control centers belonging to individual utilities, power pools, or -- most recently -- independent system operators (ISOs). Together, the RRCs compose the North American Electric Reliability Council (NERC), which sets overall reliability policies and standards.

Within each synchronous interconnection, the transmission network acts as a superhighway for electricity commerce -- carrying large amounts of power over long distances to ensure that customers have access to the least expensive sources of electricity throughout the year. In the summer, for example, air conditioners in Los Angeles use power from hydroelectric facilities in the Pacific Northwest; in winter, power flows in the other direction. The network also protects customers from outages by enabling utilities to import power when one of their own generators must be taken off-line. Transfers of power from one synchronous interconnection to another are less common, since they require an interface to compensate for the fact that AC power is out of synchronization in the adjacent areas.

# North American Interconnections & Regional Reliability Councils



### The Challenge of Reliability

For a high-voltage power network to remain stable, synchronism must be maintained. When this synchronism is disturbed by inevitable local events -- such as a sudden loss of a major transmission line or a generator -- power can begin to flow in an uncontrolled manner, causing automatic safety devices to "trip" and isolate parts of the system to prevent damage to equipment. Maintaining transmission system reliability thus depends on the ability to prevent the spread of local disturbances.

When such control is lost, widespread outages can occur -- such as those that affected the western interconnection on July 2 and August 10, 1996. The initiating causes that led to these blackouts included line sags due to hot weather, flashovers from transmission lines to nearby trees, and misoperation of relays. Electrical disturbances created by these local events spread throughout the Western transmission network, eventually disrupting power to millions of customers in several states and adjacent areas of Canada and Mexico. It has been estimated that the financial losses suffered by California industry for the August 10 outage alone -- due to lost production, spoilage, etc. -- was in the range of $1-3 billion.

The challenge of maintaining transmission reliability is thus to better understand and control disturbances that may originate in an isolated, local event but whose effects may almost instantaneously propagate throughout the system as a whole. The Northridge, California earthquake, for example, knocked generators off-line as far away as British Columbia. Fortunately, a variety of new technologies are becoming available that can help to assure transmission reliability while also enabling the grid to handle increased demand on transmission facilities that could result from industry restructuring.

### Need for Reliability Management Technologies

Ultimately, complying with these regulatory mandates will require the use of new technologies on both transmission and distribution systems. As transmission networks handle more transactions and are operated at tighter margins, for example, electronic power controllers and more sophisticated methods of monitoring, communicating and analyzing system conditions will be needed. The transition to a competitive market will lead to unbundling of energy services such that acquisition of energy will be separate from voltage support, spinning reserves, standby generation, congestion management, and other ancillary services. This creates the opportunity to develop and demonstrate distributed technologies for the specific purpose of reliability management such as distributed generation, energy storage systems, voltage controllers, local network management system protection, and other technologies.

This report by the Electric System Reliability Task Force (Task Force) addresses some of the technical issues raised by restructuring and describes several of the advanced technologies that can be used to sustain system reliability while opening transmission networks to increased competition.

**Section 2 -- Requirements for Communications, Databases, Control Systems Integration, and Information Management**

Reliable operation of the bulk power system is currently supported by sophisticated computerized information management and control systems, which rely upon one or more databases and which utilize data communications systems. The systems currently in place have been procured by the transmission owners from a variety of vendors. With few exceptions, the systems in place today have proprietary communications protocols, database formats, and operational models, and were designed to support a relatively limited number and variety of transactions.

Now, the bulk power system is being asked to support an increasing number of ever-more diverse transactions. Additionally, wholly new reliability organizations -- such as the California ISO -- are being established in some parts of the country, with needs for new and complex information systems. Indeed, in California, where retail choice was expected to be launched on January 1, 1998, a short-term delay was needed to give adequate time to prepare ISO computer systems for full-scale operation. In order for the bulk power system to be operated reliably even in areas where such new systems are not being built from scratch, existing information and control systems must be upgraded to support the new transaction levels and unbundled services. In addition, as regional coordination is implemented, through ISO's or other organizational means, information sharing and communication between transmission system control centers become even more important.

The industry is aware of the issues presented here, and there are efforts under way by leading organizations (including NERC and the Electric Power Research Institute (EPRI)) to find solutions to these problems. The intent of this section is to highlight the principal technical concerns and to recommend how they should be addressed to assure reliable operation of the bulk power system in the future. These concerns are grouped according to their relevance to communications, databases, control systems, information management, and training.

### Communications

The bulk power system is operated by personnel in control centers who must communicate effectively with their counterparts controlling other parts of the interconnected grid. Effective communication and information sharing is currently difficult and often does not occur adequately. The primary reason for this is the use of mutually incompatible communications systems. In the near term, new interfaces for inter-control center communications need to be developed and deployed. In the longer term, a non-proprietary communications protocol needs to be adopted industry-wide to insure communications compatibility of all control centers.

*The Task Force recommends that an appropriate, non-proprietary standard for communications among control centers be adopted by the Self-Regulating Reliability Organization (SRRO) and endorsed by the Federal Energy Regulatory Commission (FERC).*

### Databases

New requirements for data models and database integration arise in an ISO where regional operators must coordinate operations across larger areas with many multi-party transactions taking place. Standards are needed which support information sharing between system operators, and which support the needs of all parties engaged in transactions.

Regional operators coordinating the efforts of multiple interconnected transmission systems will be less familiar with the details of some of the networks that make up their region. They must also coordinate the control of a much larger network than current system operators. The databases needed to support regional operations therefore must contain a great deal more knowledge of the system than previously required. In addition, data models for ISOs must support data from multiple sources to coordinate energy management functions across multiple, dissimilar energy management systems within a region.

*The Task Force recommends that an appropriate, non-proprietary database access standard for control centers be adopted by the SRRO and endorsed by the FERC.*

### Information Management

Much of the information regarding the infrastructure of the bulk-power system currently in use is based on design specifications and as-built drawings. This information is largely dated and may not reflect the current status of the infrastructure with respect to available transfer capacity and safe operating margins. In addition, much of this information is only available from paper records or proprietary computer-aided design file formats. System operators must update and maintain transmission records appropriately to reflect current system capabilities and safe margins. These records must be made electronic and shared in accordance with FERC Orders 888 and 889.

As regional system operators are required to coordinate activities across larger segments of the interconnected grid, they will require information displays which cover larger geographic areas and integrate views of system models, load, status and available capacity data, weather data, risk assessments and safe operating margins. In addition, it is critical to have simulation capability to predict, prepare for and possibly mitigate congestion, and to understand the consequences of transactions and system state changes before they occur.

*The Task Force recommends that the SRRO specify information management protocols that will ensure the complete interoperability of system operations records in compliance with FERC Orders 888 & 889.*

In addition, the movement to competitive markets combined with trends toward increasing utilization of computer networks for information management and growing vulnerability to cyber threats indicates the need for substantial attention to information assurance. The recently completed report by the President's Commission on Critical Infrastructure Protection documents major threats and vulnerabilities to our critical infrastructures, including the electric infrastructure, and highlighted cyber vulnerabilities as one of the principal areas requiring attention.

*The Task Force recommends that the Department of Energy (DOE), in collaboration with the SRRO, EPRI, and other Federal agencies, examine information assurance issues for the interconnected electric system and establish appropriate cooperative programs to address these issues as warranted.*

### Training

As the industry moves to adopt these technical systems, it also needs to assure that the personnel who operate them are adequately trained in up-to-date systems, operating procedures and market protocols. Currently, there is a growing shortage of technically trained personnel who are essential to operating a reliable transmission system. In response to this need, the NERC has initiated a standard training program, which all control operators will have to pass by 2001.

*The Task Force recommends that an appropriate training program for system operators be developed by the SRRO and endorsed by the FERC.*

## Section 3 -- Planning Tools for Increased Uncertainty

The 1996 breakups of the Western power system demonstrated the need for improved resources to deal with the unexpected. This is a problem that existed prior to wide-scale industry restructuring, and it is likely to continue as competition introduces a greater number of transactions, covering wider geographical areas and multiple control regions.

### Treating Uncertainty in Reliability Assessment

Even if suitable planning models had been available, operating conditions preceding the August 10 breakup were far from normal and had not been examined in system reliability studies. These are generally performed weeks to months in advance, and planners cannot anticipate all combinations of seemingly minor outages that operation of a large power system may involve.

Short-term planning for uncertainty and the risks attending it can be mitigated in part if system capacity studies are performed with a much shorter forecasting horizon, based upon reasonable extrapolations of present operating conditions. This calls for much broader real-time access to those conditions than any one (regional) energy management system now provides. The mathematical problem for longer-term planning is even more formidable. The number of likely contingency patterns, already huge, is becoming more so in response to energy market changes. The Western Systems Coordinating Council and individual companies are already studying risk-based transmission planning. A discussion of specific technological developments required to address these issues is given below.

## Technologies for Reliability Assessment

The requisite computer tools for treating uncertainty in reliability assessment over short time periods are currently being developed as part of the envisioned framework for Dynamic Security Assessment software. For longer term planning, future practices may represent model errors as contingencies. Even without this additional step, direct examination of each individual contingency pattern is not computationally feasible. Never a simple matter, contingency analysis must now reflect new linkages between system reliability and market economics, while observing mandates supportive of the public interest. Consequent decisions must be rendered in less time, in an environment of more uncertainty and risk.

Providing reliable and economical electricity in a more complex environment requires two parallel efforts toward better decisions. The first is to reduce uncertainty, in all its forms, through better and more timely information. The second is to use planning and decision tools that directly accommodate such uncertainty as still remains. The quantified descriptions of uncertainty that such tools require as inputs are products of the information process, and directly useful for many other purposes.

Developing analytical methods to deal with greater uncertainty is necessarily a broad, multi-faceted effort. New technologies to be addressed by this effort may include:

- Mathematical tools that can examine power system signals for warnings of unstable behavior, in real time and very reliably;
- Mathematical criteria, tools, and procedures for reducing and/or characterizing errors in power system models;
- Characterizations and probabilistic models for uncertainties in power system operating conditions;
- Probabilistic models, tools, and methodologies for collective examination of contingencies that are now considered individually;
- Cost models for use in quantifying the overall impact of contingencies and ranking them accordingly (It is essential that these models be realistic, and suitable for use as standards for planning and operation of the overall electrical grid); and
- Risk management tools, based upon the above probabilistic models of contingencies and their costs, that "optimize" use of the electrical system while maintaining requisite levels of reliability.

## Need for a Collaborative Approach

Development of the indicated technologies can be expedited through technology transfers from outside the power industry. Even so, there remain several difficult problems. The knowledge base for actual power system dynamics, required both to define the subject technology and to obtain best value from its use, is not well evolved. Both should develop together, in or close to a practical field environment. That environment must also provide good observations of power system dynamics, leading edge planning tools, and knowledgeable staff.

*The Task Force recommends that appropriate entities, such as the DOE, in cooperation with the electric power industry, develop risk-based analytical tools for reliability assessment and transmission investment planning.*

## Section 4 -- Application of Alternatives for VAR Support and Reliability Management

For any transmission system to function properly, its voltage must be supported by injection of reactive power, measured as volt-amperes reactive (VARs). Compared to the "real" power delivered from a generator to a load where it can perform useful work, reactive power maintains the constantly varying electric and magnetic fields associated with all AC circuits. For transmission networks, reactive power has primarily been provided as an ancillary service by central station generators. This need for VAR support is particularly acute in areas where power demand is met primarily through the importation of power from outside the local area.

It is possible to provide VARs through other means than generation, such as through the use of fixed mechanical capacitor or reactor banks and, more recently, through the use of power electronic controllers known collectively as Flexible AC Transmission (FACTS) devices. There are pros and cons to the use of such electronic controllers, however, ranging from cost effectiveness to effects on system reliability. The potential impacts of providing increased VAR support through the use of FACTS controllers therefore needs to be carefully assessed.

Additional alternatives include a variety of Distributed Resources (DR) -- which can provide both local, on-site generation and VAR support in the form of micro-turbines, fuel cells, demand reductions and photovoltaic devices. The use of DR can enhance system reliability by providing local generation for direct support of the distribution system. DR technologies may appear particularly attractive in situations where power system enhancements are required to avoid congestion costs and/or where generation close to load is being retired.

*The Task Force recommends that the DOE undertake a comprehensive study of technological alternatives to central station VAR support, their potential impact on bulk-power system reliability, and impediments to the use of such alternatives. The Task Force recommends that the DOE consult with various industry participants, and report the results back to the FERC and the SRRO.*

## Section 5 -- Status of Reliability Research

The Task Force was briefed on reliability research programs of EPRI, vendors and the DOE.

Historically, there has been support for technology development through utility and industry collaborative research activities including funding from the DOE. There is consensus on the need for continued support for such technology development.

There are some significant issues concerning how such technology development should be supported. As the industry transitions to a more competitive model, there is both a reduction in funding from traditional sources and a need to develop alternative technologies for reliability management. Specifically,

- • DOE funding for reliability and transmission has declined substantially;
- Direct utility funding of research programs is being eliminated or significantly reduced;
- EPRI focus on transmission and distribution research has shifted from long-term to near-term payoff. In this environment, the traditional long-term focus that produced FACTS technologies would not be possible;
- Responsibility for reliability management is changing and there is a question about who is responsible for technology investments; and
- New tools and technologies are needed to address the need for reliability management in a more competitive market. For example, unbundling voltage support may require use of distributed technologies.

The Task Force recognizes that there are major technological areas relative to reliability R&D that need to be addressed. The Task Force is concerned that reliability-related R&D with long-term focus may be under funded by market forces alone. The DOE should monitor the funding gap from traditional sources and the need for alternative technologies to assure this need is addressed and a technology gap does not develop in reliability management technology.

*The Task Force recommends that the DOE carefully monitor research on reliability technologies and make appropriate recommendations to the FERC and Congress to assure that gaps do not develop.*

There are several technological areas with major potential impact on reliability. Eight of them are discussed below.

### Electrical Energy Storage

Although some technologies for electrical energy storage have been used for a long time, their use has been limited. Relatively inexpensive, large-scale technologies -- such as pumped hydro -- can be used to provide extra energy to meet peak demand, but they cannot respond rapidly enough to counteract transient disturbances. Storage technologies with rapid response times -- such as batteries -- on the other hand, have been too expensive for widespread use in peak shaving. Now, with electricity becoming more of a commodity, the need for a new storage technology that is both fast and inexpensive has become more urgent.

One promising technology now under development is superconducting magnetic energy storage (SMES). Recently, new concepts have been developed that greatly improve cost effectiveness of magnetic energy storage for both electrical system ride-through of disturbances and for transmission line stability enhancement. Cost-effective designs based on fully-developed, low-temperature superconducting cable now allow less than one cycle response for ride-through of transients or multi-seconds outages at large, power-quality sensitive industries. Recent analyses also show that rapid injection of real power from such magnets enhances the effectiveness of FACTS controllers in providing transmission stability.

New, high-temperature superconducting (HTS) materials may someday help lower the costs of SMES. Although HTS materials are themselves still costly, they are much less expensive to refrigerate, because they depend on cooling with liquid nitrogen, rather than liquid helium.

Superconducting storage technology is generally in the prototype demonstration phase. HTS materials are currently being tested in cables but are not yet ready for use in SMES because the HTS materials do not conduct well in high magnetic fields. Better HTS materials need to be developed that can withstand the high magnetic fields inherent in SMES devices. In addition, an industrial infrastructure must be established that is capable of producing the thousands of miles of HTS tape that would be used in SMES devices.

**Distributed Resources as Power System Alternative**

As mentioned earlier, DR include a variety of energy sources -- such as small combustion turbines, photovoltaics, fuel cells, and storage devices -- with capacities in roughly the 1-kW to 10-MW range. Deployment of DR on distribution networks could potentially increase the reliability and lower the cost of power delivery by placing energy sources nearer to demand centers. By providing a way to complement conventional power delivery systems, DR could offer supply flexibility, including greater use of environmentally benign renewable energy. DR can also be combined with power electronic controllers, which will provide the interface between small generation units and a utility distribution system.

Rapid introduction of DR could have profound effects on the operation and reliability of the power delivery system. An EPRI study indicates that DR could represent as much as 25% of new generation by 2010; a similar study by the Natural Gas Foundation concluded that this figure could be as high as 30%. One driving force will be the availability, within five years, of 25-100 kW microturbines for under $300/kW. Another driver may be the recent development (with DOE funding) of an electric car based on fuel cells that use gasoline -- a technology that might eventually enable consumers to use their car's 50-kW fuel cell (or similar stationary fuel cells, perhaps running on natural gas) to power their homes during hours of peak demand.

## Technologies to Expedite Customized Service

The basic design of many of today's distribution systems dates back to the 1950s and before, when electric reliability was not as critical as today. As deregulation provides customers with greater choice among retail electricity providers, competition will drive customization of service to meet the divergent needs of various market segments. In addition to their need for greater power reliability at the system level, customers are demanding lower rates and a greater variety of service options. In response, many utilities and power suppliers are experimenting with real-time pricing and seeking ways to integrate electricity with other services, including gas, cable, and telecommunications.

To accommodate these service alternatives, integrated communications and control will be needed to expedite data exchange and real-time operational command throughout a more decentralized and complex distribution system. The technical basis for such integration is currently being provided by the Utility Communications Architecture (UCA), which specifies open-systems protocols and standards for linking hardware and software from different vendors. The first utility demonstration of UCA's ability to provide the technical basis for integrating electric, telephone, water, and waste-water services is just getting underway.

Customer interface improvements will also be critical to offering new retail services. In particular, a low-cost electronic meter with two-way communications capability is needed to provide real-time pricing options. Even more sophisticated interface technologies will be required to facilitate integrated services that depend on high-bandwidth communications links. Customer interface research has reached the stage of conducting tests on pilot installations of a low-cost electronic meter. Development of a prototype hardware system for automatic meter reading using open networking standards is expected by 2000.

## Electronic Controllers for Transmission Systems

Electromechanical controllers are too slow to govern the flow of alternating current in real-time, as needed to control loop flows and bottlenecks. FACTS is a family of high-voltage electronic controllers that can increase the power carrying capacity of individual transmission lines and improve overall system reliability by reacting almost instantaneously to disturbances. The advent of such "fast-VAR support" to replace the "slow-VAR support" provided by conventional control devices will also enable system operators to "dispatch" transmission capacity in much the same way that generator capacity is now dispatched.

FACTS technology has been under development for nearly twenty years and is now entering its third generation, with devices that can control all the parameters of power flow simultaneously without the need for large external circuit elements, such as a capacitor bank. Although FACTS technology has been demonstrated in various settings, the major challenge to full-scale commercialization is the need to reduce costs to achieve widespread use.

New semiconductor materials -- such as silicon carbide, gallium nitride, and thin-film diamond -- represent a technological "wild card" that could dramatically lower the cost of FACTS devices by providing the basis for developing a power electronic equivalent of the integrated circuit. Also, the promise of going to a totally electronic device and thereby reducing costly transformers, would represent a significant cost breakthrough.

**System Coordination Technologies for Power Grid**

For transmission systems, the advent of new technologies could make it technically possible to integrate the North American power grids. In addition to this technological "push," there is a regulatory "pull" designed to reduce wholesale electricity prices by facilitating competition in the bulk-power market. The result will be to make transmission lines the superhighways of electricity commerce -- carrying low-cost power over longer distances to meet the needs of customers who may now have electricity rates higher than those in neighboring regions.

If greater long-distance transfers of power are to be accomplished while maintaining power system reliability, improvements will be needed in network monitoring, on-line analysis, and system control.

A Wide-Area Measurement System (WAMS) provides the real-time information needed for a large, highly interconnected transmission network, based on satellite communications and time-stamping. By constantly monitoring conditions throughout a wide-area network, WAMS can detect abnormal system conditions as they arise, enabling the system to operate closer to its limits. WAMS technology is currently being incorporated into a major collaborative program to implement a synchronized monitoring system for the western North American power grid.

On-line system analysis will be needed in order for the information supplied by WAMS to be interpreted in real-time for use in directing FACTS devices to respond in a timely way to disturbances as they develop. On-line software tools will enhance the ability of dispatchers to schedule wholesale power transfers on a continental scale, hour-by-hour. Such tools will be critical for enhancing reliability, promoting open access, transferring low-price electricity over longer distances, and reducing operating costs significantly. Advanced software can also provide a probabilistic measure of Available Transfer Capability -- essentially a "reliability meter" dispatchers can watch in order to maximize power flow within the stability limits of their system.

Hierarchical control of a transmission grid involves coordinating intelligent local operation of power flow devices with system-level instructions from a dispatch center. Such control will have to become widespread in order to facilitate the vision of highly reliable, long distance power transfer. System operators need the ability to understand disturbances that may be developing in neighboring regions in order to properly ensure that they do not spread and that stability is maintained throughout the rest of the grid. Hierarchical control will be able to raise the power transfer limits of transmission systems over increasingly wider areas.

### Electronic Controllers for Distribution Systems

Custom Power is the name used to describe a family of power electronic controllers designed for use on distribution systems to improve power quality levels, facilitate distribution automation, and expedite integration of distributed resources into the power system. Custom Power devices provide the key to reliability enhancement for customers. The cost of power electronics has declined to the point that this technology can be considered for use in controlling distribution systems, which require smaller, more numerous, less expensive installations than those involved in FACTS. Custom Power devices are now beginning to enter utility service and are expected to become commonplace over the next decade, as the price of electronics continues to fall. Custom Power devices can also be used in distribution automation applications to provide real-time network control and significantly reduce distribution system operating costs.

The major stumbling block to faster deployment of Custom Power devices is cost, and considerable R&D is still needed to re-engineer these controllers for greater efficiency. Again, the possible future use of new semiconductor materials offers a "wild card" chance of significantly lowering hardware costs. New designs for individual Custom Power devices may also be able to eliminate the need for incorporating costly transformers into these controllers.

### Dynamic Integration of a Silicon-Intensive Load

Twenty years in the future, power systems will be faced with increasingly silicon-intensive loads. As a result, the mechanical inertia of the system will be less than with today's motor-intensive loads. Because such inertia helps the system "ride through" momentary disruptions, the coming of predominantly silicon-based loads could contribute to dynamic instability.

More research needs to be focused on the unique reliability problems that could result from evolution of all-silicon loads. As a first step, computer models are needed that can identify the characteristics of such systems. In addition, the use of energy storage to replace the effects of mechanical inertia needs to be explored.

### Development of an All-Underground Power Delivery System

Construction of new overhead transmission and distribution lines is becoming more difficult because of problems in siting and obtaining the necessary permits. By contrast, gas transmission companies have met much less resistance in siting new lines because they are underground. In addition, because underground facilities are generally less susceptible to disruptions caused by natural disasters, such as ice storms, their increased use could improve transmission reliability. The cost of putting electric power lines underground, however, can range up to a factor of ten higher than for overhead installations of equivalent capacity.

Recent experience indicates that this cost differential could be reduced through research. In many cases, for example, directional drilling can be used instead of traditional trenching methods to install conduits for new underground lines. Such guided boring technology can not only lower construction costs in many instances but also substantially reduce environmental impact of installation. Further research can be expected to bring the life-cycle costs of undergrounding much closer to the equivalent costs of overhead alternatives.

## Section 6 -- Conclusion

Given the current restructuring of the U.S. electric industry, maintaining the reliability of the transmission systems will require careful integration of existing systems and advanced technologies. Deployment of advanced technologies needs to be coordinated in accordance with regional and national standards and procedures. Such standards and procedures should be adopted.

The Task Force has made several specific recommendations summarized below, which support the timely and effective use of reliability-related technologies. We believe the adoption of these recommendations will increase the probability of maintaining reliable transmission system operation, resulting in lower costs and improved service to electricity customers throughout the country.

### Recommendations Summary

The Task Force recommends that:

1) An appropriate, non-proprietary standard for communications among control centers be adopted by the SRRO and endorsed by the FERC;

2) An appropriate, non-proprietary database access standard for control centers be adopted by the SRRO and endorsed by the FERC;

3) The SRRO specify information management protocols that will ensure the complete interoperability of system operations records in compliance with FERC Orders 888 & 889;

4) The DOE, in collaboration with the SRRO, EPRI, and other Federal agencies, examine information assurance issues for the interconnected electric system and establish appropriate cooperative programs to address these issues as warranted;

5) An appropriate training program for system operators be developed by the SRRO and endorsed by the FERC;

6) Appropriate entities, such as the DOE, in cooperation with the electric power industry, develop risk-based analytical tools for reliability assessment and transmission investment planning;

7) The DOE undertake a comprehensive study of technological alternatives to central station VAR support, their potential impact on bulk-power system reliability, and impediments to the use of such alternatives. The Task Force recommends that the DOE consult with various industry participants, and report the results back to the FERC and the SRRO; and

8) The DOE carefully monitor research on reliability technologies and make appropriate recommendations to the FERC and Congress to assure that gaps do not develop.

# Appendix F

# Incentives for Transmission Enhancement

July 1998

# INCENTIVES FOR TRANSMISSION ENHANCEMENT

A Position Paper of the
Electric System Reliability Task Force
Secretary of Energy Advisory Board
July 9, 1998

## 1. INTRODUCTION

The U.S. electric industry is characterized by many vertically-integrated utilities, each of whose generation and transmission systems were planned and for the most part are operated as an integrated whole. Restructuring of the electric-power industry and unbundling of transmission from generation create challenges for reliably operating the existing transmission system and raise concerns about the future adequacy of transmission planning and incentives for investment in transmission enhancements.[1] In the future, decisions regarding whether to build transmission or generation or both, or to dispatch customer load reductions will be made by multiple market participants, with decisions about one approach or another being informed by but not necessarily integrated with decisions about other approaches.

Traditionally, transmission has been viewed as a monopoly function, with utility investments recovered through regulated rates. If, however as some believe, grid construction and maintenance lack compelling natural monopoly characteristics, regulated systems of cost recovery may not long endure at state or other levels. Even acknowledging this viewpoint, the Task Force nonetheless believes that this sector's monopoly aspects remain robust enough to justify improving rather than dismantling price regulation. And we are concerned that state and federal-level regulation is not doing enough to promote and shape sound investments in grid reliability.

This paper discusses these issues of ensuring adequate incentives for transmission enhancement, starting with a brief background on the historical industry structure to place these concerns in context. The nature of operational reliability and transmission congestion (typically the driving force for transmission enhancement), and physical interactions among generation, transmission, and demand-side alternatives, are also examined. The paper also discusses alternative industry structures and the issues they raise with respect to incentives for adequate transmission enhancements. Finally, the paper suggests Task Force recommendations on Federal Energy Regulatory Commission (FERC) rules, market structures and future research. These recommendations relate to adequate incentives for efficient transmission enhancements and

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1 Transmission "enhancements" can include construction of new transmission lines, substations, and facilities; upgrading existing lines and facilities; deployment of new technologies such as FACTs devices and distributed generation; or the implementation of advanced controls that increase the capacity of the existing system; and for the purposes of this discussion, demand-side alternatives that relieve congestion.

dovetail with other recommendations adopted by the Task Force on Electric System Reliability.[2]

## 2. HISTORICAL INDUSTRY STRUCTURE

Historically, vertically-integrated electric utilities designed and operated integrated transmission and generation systems. The primary historical transmission function was to connect the utility's generators to the utility's customers and to operate the system reliably. Utilities interconnected their transmission systems with other utilities' systems to increase reliability and share reserves, as well as take advantage of economic exchanges. When transmission congestion required generation to be re-dispatched to support reliability or economic transactions, the utility was able to evaluate generation and transmission implications (and even occasionally load-reduction options) in both a real-time basis and for long-term planning purposes, if needed. A solution for new transmission facilities, based upon current conditions as well as expectations for load growth and future electricity prices and availability, could be developed and presented to the regulator for approval, subject to a number of constraints relating to siting and cost issues. The selected strategy could then be implemented and the costs passed on to customers. Investment decisions were made by utilities and regulators with prudent investment and operational costs borne by customers.

## 3. CONGESTION RELIEF: PHYSICAL ALTERNATIVES AND INTERACTIONS

In the absence of congestion (current or anticipated) and short of operational reliability problems, there is no need to invest in transmission expansion; the existing system is adequate to handle all desired transactions on a reliable basis. In theory, such a system can allow for a minimum-cost dispatch of generation (and load reductions). Congestion results when there is a desire (for either reliability or commercial reasons) to move more power through a transmission line (or set of transmission lines or an interface) than the transmission line (or interface) can accommodate.

Figure 1 presents an example where the flow from Area A to Area B can become congested.[3] A consequence of a congested interface is that it creates a bottleneck which prohibits delivery of otherwise economic energy supplies to consumers on the high-cost side of the bottleneck. This

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2 The following reports have been approved by the Secretary of Energy Advisory Board, Task Force on Electric System Reliability:
- July 1997, *Interim Report*,
- November 1997, *Maintaining Bulk-Power Reliability Through Use of A Self Regulating Organization*,
- March 1998, *The Characteristics of the Independent System Operator*,
- May 1998, *Technical Issues in Transmission System Reliability*,
- May 1998, *Ancillary Services and Bulk-Power Reliability*.

3 Figures 1 and 2 are simplifications for illustrative purposes. In reality, transmission interfaces are generally crossed by multiple transmission lines.

means that these consumers pay more for their power than they would if there was sufficient transmission capacity to carry all economic transactions. In other words, energy costs are genuinely location dependent, given transmission constraints. When the load in Area B reaches a level where the transmission interface is fully loaded (800 MW in this example) and no more power can be delivered from Area A to meet demand in Area B, then more expensive generation than would otherwise be required (G1 at $28/MWh, or $6/MWh above the Area A cost) must be run in Area B. Although congestion is based upon reliability requirements, the consequences are economic.

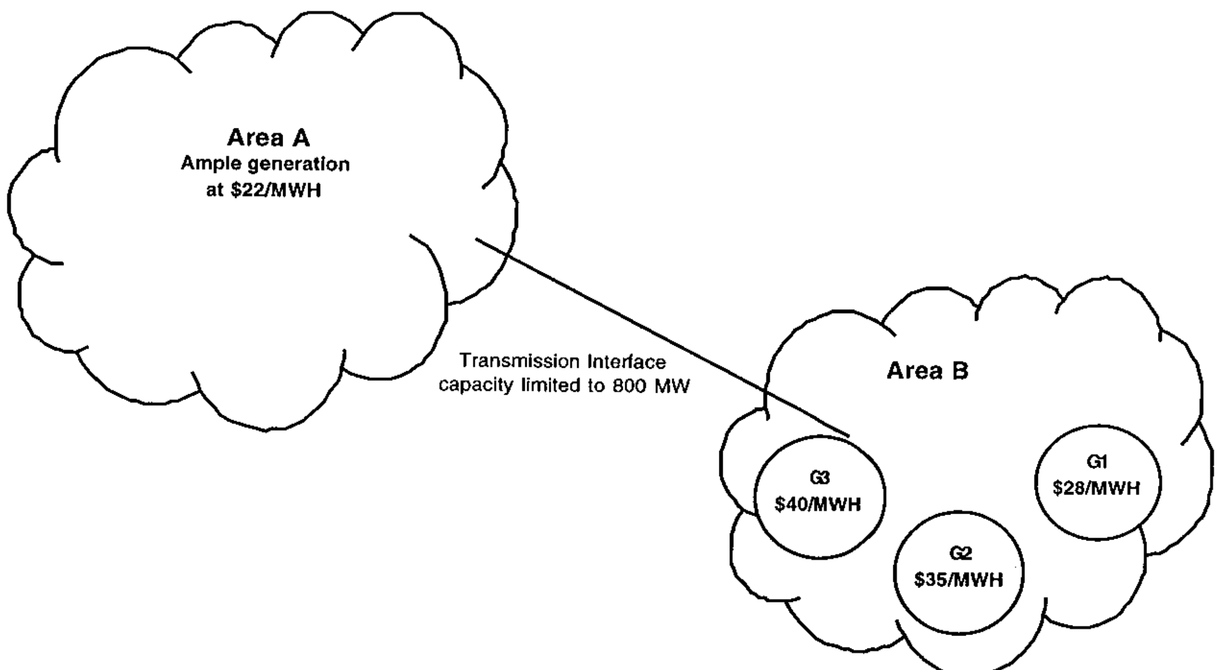


Figure 1 Congested transmission interface that limits power flows from Area A to Area B

Presuming that congestion results in economic inefficiencies, the option to relieve congestion through transmission enhancements is desirable where cost-effective. In any particular circumstance, there are usually several alternatives to relieve congestion and the goal should be to devise systems of incentives that produce cost-effective means to reduce such congestion where it is economical to do so. Effective relief methods can include installation and/or operation of large or small scale generation in the congested area for energy production, for voltage support, to enhance stability, or to reduce flows on specific lines. Transmission-based solutions can include construction of new lines or facilities, upgrading of lines or facilities, installation of voltage

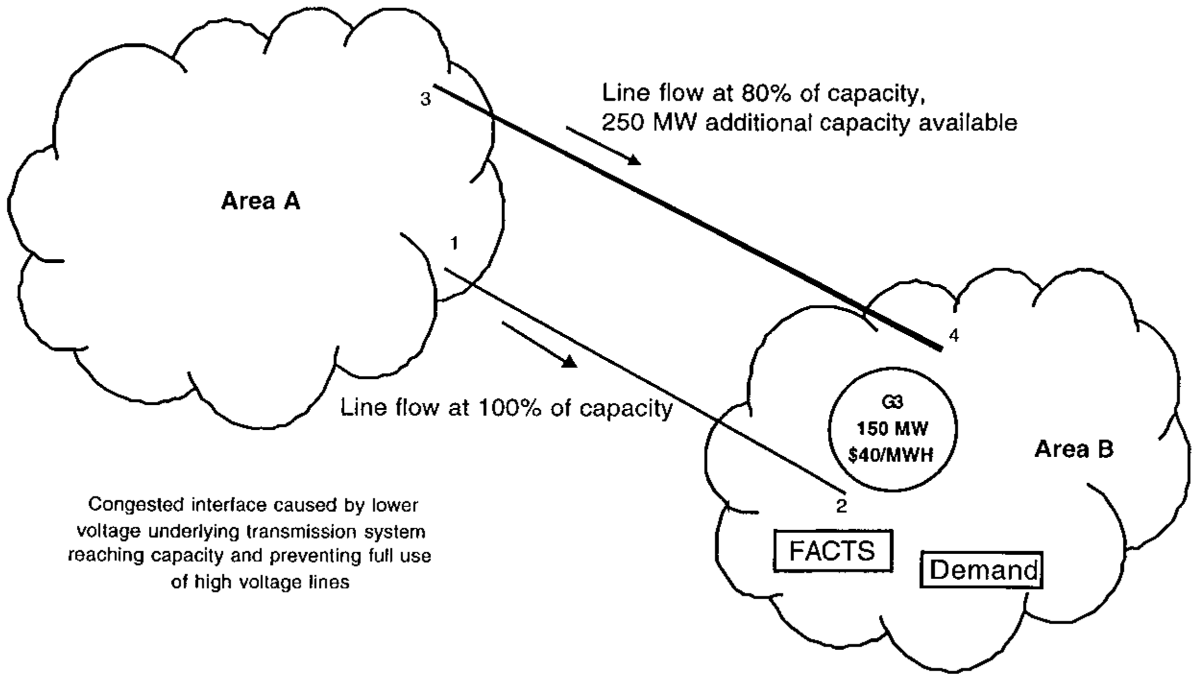


Figure 2 Alternatives to limit flows on line 1-2 and allow use of additional capacity on line 3-4

support (capacitors, inductors, voltage regulating transformers, static condensers, or static var compensators), or installation of flow-control devices (phase angle regulators or FACTs devices), and power system stabilizers at generating stations. The technologies allow more power to be delivered over a line or to operate the system more reliably. Load management approaches (including bidding interruptible load in response to different market clearing prices) can also provide congestion relief under certain circumstances. The incentives (and moreover, disincentives) for a particular type of relief depend on various economic, technical, informational, and regulatory elements.

By way of example, Figure 2 shows a situation where one of two parallel paths is loaded to capacity before the other, leaving 250 MW of transmission capacity unavailable to support power transfers. Accepting the transmission limit and allowing the more expensive generation market in Area B to operate may be the best solution if the congestion is infrequent, does not last long, or the price differential between areas A and B is not great. Alternatively, a FACTs device or phase-angle regulator could be used to block the flow on the limiting line, allowing additional power to flow on the line with remaining capacity. Running a specific unit (generator G3 in this case, located at the delivery end of the congested line) out-of-economic-merit order may reduce flows on the limiting line sufficiently to allow additional energy to be imported over the parallel path. Similarly, controlling demand, either throughout Area B or specifically near the termination of the limiting line, can relieve congestion. In all cases, a transmission enhancement is required to reduce the cost of service in Area B.

## 4. ISOs AND CONGESTION RELIEF

Independent system operators (ISOs)[4] have been proposed as a way to facilitate competitive generation markets in an environment where some power-system facilities and functions remain inherently monopolistic. This Task Force has recommended that ISOs have broad geographic coverage. Where ISOs have been established as the means to assure non-discriminatory access to transmission for all generators in a region's wholesale (and retail) power markets, functions that require allocation of existing scarce monopoly resources, such as existing transmission capacity, among competing parties in an agreed manner should be under the control of the ISO. Rules governing the desired level of reliability can be established as can rules governing the relative priorities of individual transactions in use of the transmission system. With rules in place an ISO can then determine how best to operate the transmission system to reliably accommodate as many users as possible on a non-discriminatory basis, and allow competitive markets to function. Market rules can be designed that solicit and select among generation redispatch, demand-side solutions, or transaction curtailment as ways of dealing with specific congestion, both on a long-term planning basis and in real-time operational markets.

Two fundamental problems arise, however, when trying to decide whether it is desirable to make capital investments of one sort or another to alleviate congestion. The first problem is that there is no agreement on the appropriate way to price use of transmission from the point of view of creating efficient price signals for investment (supply) or use (demand). PJM is using location-based marginal energy prices and firm transmission rights as the means for indicating the need for and cost-effectiveness of investments in transmission enhancements. In other regions such as New England, market participants have adopted a region-wide postage stamp pricing system for transmission, with cost allocation for new transmission enhancements still in discussion. There is no national consensus on the correct approach, or on which approach creates the proper incentives for investment. However, with a variety of pricing approaches in place across the country, actual experience will help increase our understanding of the advantages and disadvantages of the different approaches to transmission pricing.

The second problem is that competing options for relieving congestion operate in different markets with different structures: generation and demand-side solutions operate primarily in competitive markets, while transmission remains largely a regulated monopoly service. When a single investment (a generator, for example, or a special technology[5] added on to transmission facilities which enhances the capabilities of generation resources) is selling into both a competitive and a regulated market, it is difficult to unambiguously determine the appropriate allocation of costs between those markets and to establish appropriate incentives for efficient investments (or product substitution) in those markets. Uncertainty may lead to under investment or cross-subsidization.

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4 The ISO could be a Transco or other type of system operator so long as it does not have a financial interest in energy markets.

5 Special technologies might include fixed capacitors, inductors, or power electronic controllers.

The lack of an accepted method for individual transmission facilities to competitively price their use makes it unclear that the same market forces that are expected to work well for generation investment can be harnessed for transmission. With generation, an investor can evaluate a potential market, develop a project proposal at a particular location, determine expected costs and profits, and then decide if it wants to risk its capital. After the facility is placed in operation, its use and profitability depend on how the owner operates its facility and prices the production and how the market responds to these and other price offers. Transmission is inherently different. The extent to which a transmission element is used in real-time depends on the electrical impedances and the overall system flows, not the price charged for the service. With very few exceptions, customers can not choose the path on which power will flow based upon offered price.

For the time-being (at least) and for the long-term (at most), responsibility for grid construction, operation, and maintenance is expected to be a monopoly with its use and cost overseen by government regulators and operated in many parts of the country by independent system operators. Although ISOs are expected to be adopted, their exact scope is not known and will probably vary from region to region. ISOs should conduct planning and implementation for transmission enhancement, much as vertically integrated utilities do today and provide congestion-based signals so that markets might resolve congestion-related problems through market forces.

An ISO would identify constraints where congestion was likely to impact reliability. It could then do a variety of actions. It might ask the local transmission company to build transmission, or it might request proposals to construct and/or own the needed facility. Other ownership structures and other physical solutions (non-transmission) may be proposed for the ISO to evaluate. It might share pricing and other planning information with other market participants. The ISO might request proposals for solutions. Proposals could be generation, transmission or load based. The ISO could select the least-cost solution for the overall system and would support approval from the appropriate regulatory authority for investments made by others (e.g., generation developers or transmission owners), the requestor of firm transmission service that caused the need for new transmission enhancements, or the ISO[6] itself. The solution could be implemented and the costs could be included in overall transmission rates.

An ISO would also provide congestion-related pricing signals to transmission users when allocating access across constrained interfaces and through settlements on contracts following implementation of measures to relieve reliability constraints. Transmission capacity constraints would be based upon reliability criteria and transmission loading.[7] Market participants themselves could decide whether and when to propose transmission investments. In the absence of investment, any resource which is fully interconnected with firm transmission rights would enjoy priority service during periods of congestion.

6 The independence of the ISO from any of the entities proposing solutions will significantly increase the confidence that all proposals are being evaluated equally.

7 Transmission constraints would be met in real time by transaction curtailment if there were not sufficient time for market response.

In recent decades, it has become extremely difficult to site and build new transmission lines, especially above ground lines on new rights of way. Regulatory requirements include environmental impact assessments, proof of need and proof that such transmission investments are the least-cost alternative. These issues of need, cost, and benefit are complicated when transmission operates in interstate commerce with the distribution of benefits and costs imperfectly aligned with state boundaries.

Furthermore, there are significant timing issues regarding the lead times for new generation investments made in response to market price signals - which might take 10 - 48 months, depending upon the type of generation investment - and the lead times for transmission enhancements - which may take as little as a year or two for certain technical solutions or as long as 5 - 10 years for construction of major new transmission lines. In a generation market with increasing energy prices, there could be a demand for new generation, but the timing misalignment between transmission planning and investment (including permitting) and generation siting and investment could create a significant barrier to entry for new generation. A reactive approach to transmission planning, in which transmission analyses are carried out in response to generator requests for firm transmission, will exacerbate this problem.

## 5. TASK FORCE FINDINGS AND RECOMMENDATIONS

Investors, under any structure adopted, will require clear and stable rules to encourage them to risk their capital. As well as being clear, the economic signals need to be adequate to induce appropriate investments.

- At present there is no national consensus on the appropriate way to price transmission services in order to provide optimal incentives for both investment in transmission facilities and the demand for transmission services. Given the lack of consensus, it is appropriate and desirable that a variety of approaches are being tested around the country. The FERC should monitor progress with these different pricing approaches so that we can learn more about the advantages and limitations of the alternative methods.

- Energy generation will be increasingly market based. Generation investment decisions will be made by commercial entities assuming the risks associated with their decisions. But the viability of a generator depends in part on the market it is selling into. If that market is influenced by congestion the investor will want information concerning how long that congestion is likely to last. Similarly, decisions concerning congestion relief investments should be influenced by expectations concerning future generator locations. Methods for sharing generation and transmission planning information, without passing commercially sensitive information between competitors, should be developed.

- The FERC should approve tariffs designed to compensate those entities making cost- effective investments to relieve congestion. While allowing for variation across regions, the FERC should explain the range of transmission compensation structures it will allow, and the extent to which generation investments that perform transmission functions are subject to rate regulation as transmission or conversely the extent to which transmission investment that adds to generation capacity in the region qualifies for unregulated market prices and rates of return.

- Without a robust open market addressing grid congestion, many believe there is minimal incentive for commercial entities to conduct or pay for long-term transmission research. Long-term research to advance transmission technology would then be in the public interest and should be open rather than proprietary. Broad-based mechanisms to support basic and applied technology research should be encouraged, including tax credits for long-term research with broad public benefits.

- Monitoring outcomes of changes in the wholesale electricity market is important to determining the effectiveness of the system operator and its rules. Just as the North American Electric Reliability Council makes assessments today of regional reliability and identifies sensitive situations, the national reliability organization should assess interfaces which are constrained presently and review these assessments periodically. The system operator can use this information to moderate its rules and pricing to cost- effectively reduce constraints.

# Appendix G

# Issues of Federalism in Transmission System Reliability

July 1998

# Issues of Federalism in Transmission System Reliability

A Position paper of the
Electric System Reliability Task Force
Secretary of Energy Advisory Board
July 9, 1998

## Introduction

Our federal system shares institutional responsibility for ensuring North American grid reliability; this paper addresses the role of state and regional authorities. Our focus is issues of siting and non-federal price regulation that have significant reliability implications. We address both constraints and opportunities. We also acknowledge an important threshold issue: whether the grid itself retains natural monopoly features that justify a continuing government role in regulating the prices of grid services.

If, as some believe, grid construction and maintenance lack compelling natural monopoly characteristics, regulated systems of cost recovery may not long endure at state or other levels. Acknowledging this viewpoint, the Task Force nonetheless believes that this sector's monopoly aspects remain robust enough to justify improving rather than dismantling price regulation. And we are concerned that state and federal regulation is not doing enough to promote and shape sound investments in grid reliability.[1] We also support an increased role for regional institutions that can help states resolve issues that transcend their individual boundaries.

Our paper is organized in four sections below. In section I, we begin with a critical review of state and local responsibility for transmission siting and evaluation of transmission alternatives. In section II, we then explore state roles in cost recovery and incentives for transmission enhancements, including but not limited to new transmission. The third section addresses states' participation in existing regional reliability organizations. The final section is a summary of the papers recommendations.

## Section I - Responsibility for Siting and Evaluation of Transmission Alternatives

State governments have historically had authority over the siting of transmission facilities and have provided the right of eminent domain to utilities where necessary. Frequently, state processes for review include comprehensive evaluations of alternatives to utility-proposed solutions for relieving transmission constraints. In many states siting authority has been shared with local governments.

[1] The Task Force recognizes that in many cases the costs of needed transmission improvements can be directly related to the construction of new generation facilities. In these cases, regulators may assign the costs of needed transmission improvements to the new generator. However, there also are instances where transmission improvements are needed to assure continued reliability in the face of growing regional loads or retirement of generation facilities. It is this latter situation which is the focus of this paper, although many of the issues relating to the siting of regional transmission facilities apply to the former situation as well.

As noted in the Task Force's paper[2] on Independent System Operators (ISOs), electric systems are becoming more regional in character. The reliability benefits of transmission enhancements can benefit many states, not just those where the facilities are sited. In evaluating proposals for transmission improvements, it is difficult for many states to balance the local impacts with regional benefits. Further complicating the review of proposed transmission facilities is the fact that non-transmission alternatives may be proposed by a variety of entities not subject to the same regulatory reviews.

The Task Force believes there is an increasing need for a regional mechanism to evaluate transmission enhancement alternatives and siting, provided that creating such a mechanism does not create an unwanted new layer of regulation. The Task Force believes that, through creative cooperation, states could improve today's regulatory machinery. Regional siting issues could be effectively addressed by voluntary interstate initiatives focused on transmission enhancement needs, in which states would combine multiple siting and other authorities within one Regional Regulatory Agency (RRA).

The Task Force supports the establishment of RRAs if federal legislation would:

- establish criteria that must be met by the RRA;
- authorize the Federal Energy Regulatory Commission (FERC) to approve an RRA once the FERC certifies that the RRA meets the criteria;
- authorize the FERC to give deference, where appropriate, to approved RRAs;
- specify that the FERC has regulatory oversight over RRAs in all matters except siting; and
- require that RRA member states relinquish jurisdiction over any issue addressed by an RRA and assure that no state have veto power over any decision of the RRA.

The Task Force believes, where RRAs are created by the states, their proceedings should replace otherwise applicable state and local reviews. States should not have veto power over any aspect of any RRA decision or order. Congress could help by providing advance approval and incentives for this form of interstate cooperation. The Task Force holds as a basic tenet that there be no additional layer of regulation.

States should have flexibility in organizing such initiatives. For example, an RRA could be a new, permanent regulatory body with board members appointed by the states or a temporary, specialized authority staffed by the very state agencies whose powers were being integrated for a specific purpose.

RRAs also could improve regional participation in regulatory proceedings before the Federal Energy Regulatory Commission (FERC). Where ISO[3] and RRA boundaries are concurrent the FERC should establish criteria for delegating some of its regulatory authority over the ISO to the

2 *The Characteristics of the Independent System Operator*, Task Force on Electric System Reliability, March 10, 1998.

3 See the Task Force's paper *The Characteristics of the Independent System Operator*, March 1998, for a description of ISOs.

RRA.[4] The FERC could be expected to accord substantial weight to any consensus RRA recommendations.

RRAs would be an especially useful mechanism for regional transmission planning. Regional transmission enhancements could emerge under RRAs through at least two approaches:

- One would rely on transmission price signals to elicit investments in grid enhancement and congestion relief; no grid-monopoly revenues would be allocated for these purposes.

- Where regulators elect instead to include in captive customers' rates the costs of long-term investments in grid enhancement and congestion relief, this approach could include a competitive "open season" to allocating funds, with bidders evaluated on the basis of their capacity to meet reliability standards at the lowest life-cycle costs. Potential bidders should include, but not be limited to, sponsors of new transmission lines, upgrades of existing transmission lines, new transmission control equipment, demand-side management, distributed generation, or load-side management. The ISO could evaluate the response bids to determine if they would relieve the potential transmission constraint. Those determined to meet this criteria could then be referred to the RRA. The RRA could evaluate the referred bids and select a winning bid based on cost, environmental impacts, use of resources, and any other criteria that is consistent with regional policy objectives. As part of the selection process, the RRA could grant the winner all necessary state approvals including siting permits and the right of eminent domain.

The attraction for states of RRAs would be greater influence over pricing decisions, compared to a FERC-dominated system, coupled with reduced likelihood that multi-state benefits would be sacrificed to parochial concerns. Other stakeholders would get streamlined rather than duplicative regulation. And the nation would gain by expediting cost-effective multi-state transmission enhancements.

*The Task Force recommends exploring formation of RRAs to provide an institutional focus on interstate transmission enhancement needs, the avoidance of increased regulatory burdens and the replacement of multiple siting and other authorities with single regional siting authorities which are not subject to any state veto.*

### Section II - Rate Making Issues Associated With The Expansion Of The Transmission System

Transmission issues have become some of the most controversial matters facing the electric industry today. If the demand for transmission service grows as some predict, there will be an increasing strain on many transmission systems. Accordingly, transmission owners will be forced to improve existing facilities or attempt to build new facilities if they are to maintain the required level of reliability and to accommodate requests for firm transmission service. The

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[4] Authority for the FERC to delegate some of its regulatory authority to an RRA would be included in federal legislation that establishes RRAs.

question of who should pay for such transmission improvements is important and will be the source of great tension and dispute among the various interested parties and a potentially serious hindrance to efficient expansion of the transmission system. It is imperative, therefore, that state and federal transmission pricing and cost allocation be coordinated and consistent.

The concerns of state commissions regarding protection of jurisdictional customers deserve special attention given the pivotal role that the states play in transmission siting and construction. Typically, electric utilities have a legal obligation to serve their franchise (retail) customers at the lowest reasonable cost and transmission facilities are predominately used to satisfy this requirement. Moreover, retail customers have traditionally accounted for 85-95 percent of a utility's revenues, and thus have borne a great deal of the cost burden associated with the transmission system. Therefore, there is good reason for state commissions to be concerned about the allocation of costs for transmission improvements and the impact on retail customers.

The states generally have authority over the siting and construction of new transmission facilities. A state commission may be forced to choose between its obligations regarding the siting and construction of transmission facilities and its obligations to ensure an adequate and reliable supply of power at the lowest reasonable cost to retail customers. Failure to provide the state commissions with sufficient comfort that their jurisdictional customers are adequately protected could result in a refusal by states to approve the construction of additional transmission facilities or the inclusion of associated costs in retail rates. Forcing state commissions to approve transmission construction that does not result in local benefits commensurate with increased cost to local customers would infringe on the jurisdiction of the states and would be strongly resisted. However, allowing one state to refuse to approve an enhancement that benefits customers in another state may infringe on interstate commerce. Such conflicts with the state commissions would not further the FERC's goal of promoting competition in the generation arena.

Assuming that it would otherwise be economical to build a transmission line to accommodate a request for firm transmission service, the certification, siting, and eminent domain requirements in some states may impede, if not prevent, the construction of the transmission line. In some states, only the local benefits of the line are measured. For a multi-state project, a utility might not be able to show that the local benefits of the line outweigh the local costs. This would be especially true if the line was built solely or primarily to transmit power for out-of-state entities. In particular, the states will likely deny certification of new transmission lines if local customers are not properly protected from economic harm. Fair and proper allocation of costs[5] among users will lessen the likelihood of states denying permission to construct new transmission facilities to accommodate firm transmission service on the basis that retail customers would be economically harmed (i.e., siting/certification decisions would be made independent of economic issues).

If a transmission owner is required to build transmission facilities because of an order by the FERC or because the transmission system is being used without compensation (loop flows), there will likely be under recovery of the costs of the new investment. In the first case, there will be under recovery if the costs of additions are not part of the rates in retail jurisdiction (due to denial of rate treatment by the states or due to an overall rate freeze on vertically integrated companies in a

[5] The Task Force is not advocating any specific cost-allocation methodology.

"phase-in" of retail competition). In the second case, there will be under recovery in the retail jurisdiction for the same reasons discussed above if FERC policy continues to ignore actual flows and allows transmission customers to select a contract path between the generation source and the load. In an interconnected network, the loading of transmission facilities is not determined by contracts or regulatory requirements defining the service to be provided. Rather, it is determined by the location of the power sources, the loads, and the electrical characteristics of the network. In most cases, the contract path selected by the transmission customer will have no relationship to the transmission facilities actually used to provide the service. Any pricing policy that does not recognize the actual flows and facilities used by a transaction will result in cross subsidization between customers and discourage additional investment in transmission facilities.

These factors indicate a need to have transmission treated separately for rate-making purposes. One solution is provided by the institution of ISO regional transmission tariffs whereby all parties benefiting from the new construction (not solely the customers served by the company building the new transmission assets) help pay for the new construction. In addition, regional tariffs will internalize many loop-flows, will provide revenue recovery to transmission owners, and should support pricing mechanisms that promote market-based alternatives to transmission construction.

New transmission investments (and other incremental costs) should be included in annual rate adjustments (in retail and wholesale jurisdictions) to ensure that transmission owners have an opportunity to recover transmission costs and to provide transmission owners with an incentive to invest in transmission improvements.

RRAs should ensure that customers have access to alternatives to transmission investment including distributed generation and demand-side management to address reliability concerns. RRAs should also ensure that the marketplace and the RRA's standards and processes enable rational choices between those alternatives.

Transmission rates must include a rate of return that reflects the risks associated with cost recovery in the provision of transmission service. These risks may include, but are not limited to, the following: the forecasting of load growth in each locality, the estimation of future economic dispatch of existing generating units, the forecasting of the location of future generating units on its system as well as surrounding systems, the ability to construct new transmission facilities, and the possibility that the facilities will not adequately support the transaction for the length of the transmission service contract. If transmission investors are not allowed to earn a return on equity commensurate with the risks associated with the provision of transmission service, transmission owners will have little incentive to invest additional capital in the transmission system. This could harm reliability by increasing transmission line loadings to contingency limits and reducing the transmission reserve margin in the system.

RRAs could propose a regional transmission pricing method that meets FERC guidelines and sends the appropriate signals to generating customers and transmission owners within the region. Typically, these arrangements have included some form of charge for base revenue requirements plus pricing signals to encourage the optimal location of generation. The arrangements have also typically included a phase-in to transmission cost equalization to those customers who will be responsible for paying the base revenue requirements (loads located within the region plus, in some instances, firm transmission customers who transmit through the region).

The pricing method would be arrived at through negotiations between the states and other interested parties subject to FERC approval. Parties external to the region who use the region's facilities should be required to pay for use of the region's facilities based on their impact on those facilities.

In any pricing method, the "seams" issues present the most difficult questions and so called "pancaking" still results as transactions cross multiple regions. Transmission pricing could send signals to appropriately locate new generation within the region. Minimum signals will be provided to generators who locate outside of the borders of the region.[6] The "seams" issues will be difficult but can be addressed by coordinating planning studies between transmission regions as is now done between transmission-owning companies.

*The Task Force is concerned that uncertainty about who will pay for new transmission investments will be a major disincentive to undertaking those investments. In particular, it is imperative that state and federal transmission pricing and cost allocation be coordinated and consistent. The Task Force recommends that the FERC undertake an initiative to address these concerns.*

*The Task Force recommends that RRAs ensure that customers have access to alternatives to transmission investment including distributed generation and demand-side management to address reliability concerns and that the marketplace and the RRA's standards and processes enable rational choices between those alternatives.*

## Section III - State Participation in the National Self Regulating Reliability Organization (SRRO) and Regional Reliability Organizations (RROs)

As discussed in the Task Force paper on the SRRO[7], the SRRO and RRO governing boards

[6] A possible - but radical - solution to these issues of parallel flows would be to convert all inter-regional transmission connections to DC ties or to install FACTS devices on the ties between regions. This solution would encourage the formation of large transmission regions (to internalize as many of the constraints as practical) and would solve the "seams" issues. This solution could also provide a competitive market for the provision of transmission services between transmission regions. States would be incented to join a transmission region based on the perceived advantages to their constituents (citizens). This solution does not require a state to be entirely within one region. The state could be divided on the basis of electrical or economic considerations with one part of a state in one transmission region (market area) and another part(s) could be in another region(s). An example might be Montana - with the eastern portion being in a region of the eastern interconnection and the western portion being in a transmission region in the western interconnection.

Short of a major change as outlined above, we will continue to wrestle with loop-flow issues, attributing incremental costs with incremental causes and other issues that seem to be beyond the grasp of current thinking to resolve.

[7] *Maintaining Bulk-Power Reliability Through Use of a Self-Regulating Organization*, Task Force on Electric System Reliability, November 1997.

might include stakeholder seats or independent seats or both. Regardless of the structure, the Task Force believes that states should be represented in the process of nominating and voting for board members. State and federal governments should have non-voting (ex-officio) representation at all board meetings. States would participate in the selection of board members for a particular RRO only if the state was within that region. The board compositions and voting and nomination rules should be addressed by the FERC when it reviews the SRRO for approval.

*The Task Force recommends that the FERC, when reviewing the SRRO for approval and when reviewing any agreement between the SRRO and an RRO, assure opportunity for state and federal government representation at governing board meetings and appropriate state representation in the process of nominating and voting for board members.*

## Section IV - Summary of Task Force Recommendations

The Task Force recommends:

1) Exploring formation of RRAs to provide an institutional focus on interstate transmission enhancement needs, the avoidance of increased regulatory burdens and the replacement of multiple siting and other authorities with single regional siting authorities which are not subject to any state veto.

2) That the FERC undertake an initiative to address uncertainty about who will pay for transmission enhancements and to assure that state and federal transmission pricing and cost allocation are coordinated and consistent.

3) That RRAs ensure that customers have access to alternatives to transmission investment including distributed generation and demand-side management to address reliability concerns and that the marketplace and the RRA's standards and processes enable rational choices between those alternatives.

4) That the FERC, when reviewing the SRRO for approval and when reviewing any agreement between the SRRO and an RRO, assure opportunity for state and federal government representation at governing board meetings and appropriate state representation in the process of nominating and voting for board members.