

Electric Reliability

*Potential Problems
and Possible Solutions*



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Foreword

This paper has been prepared to inform policymakers, the media, state and local officials, and the public about electric reliability in the United States. The paper explores the history of the electric power industry, focusing on the bulk-power system, and identifies potential problems that could impact system reliability. Possible solutions to reliability concerns are offered.

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Introduction

Largely because of the essential role electricity plays in our modern society, government regulators and legislators, industry leaders, and the general public are concerned about electric-system reliability. These concerns stem from events such as the two major outages in the West during the summer of 1996, dramatic increases in electricity prices in the Midwest during the summers of 1998 and 1999, and local outages in Chicago and New York during the summer of 1999. Many people ask whether these incidents were caused by the major changes underway in the U.S. electricity industry.

This paper addresses these issues. It focuses on bulk-power (generation and transmission) rather than local distribution outages. Although roughly 85 percent of all outages occur at the distribution level, bulk-power outages affect large regions and, therefore, many more people and businesses than do distribution outages. Also, bulk-power reliability is an important national public-policy issue, one for which the proper role of the federal government is hotly debated; distribution and its reliability, on the other hand, will remain a state responsibility.

The lengthy and complicated transition from an electricity industry that consisted primarily of regulated, vertically integrated utilities to one that emphasizes competitive markets raises many concerns about reliability. But there is little evidence that overall reliability levels have changed in recent years. Nevertheless, these dramatic changes in the structure, operation, and regulation of the U.S. electricity industry require that we consider analogous modifications in reliability practices and institutions.

HISTORY

The electric power industry began in 1882, when Thomas Edison offered electric lighting service in parts of New York City. During the early decades of the 20th century, the many small independent electric systems began to combine into fewer, larger systems. Because of diversity in customer loads and generator performance, it was much cheaper to serve many customers using several generators than it was to serve small groups of customers, each with their own generator. During this period, the maximum size and efficiency of generators increased dramatically.

In subsequent decades, individual utility companies began to interconnect with their neighbor utilities. These interconnections improved reliability and lowered costs. If a

large generator in one area suddenly failed, the utility could call on generation from its neighbor as well as its own system. This ability to share resources reduced the amount of extra generating capacity each utility had to maintain for reliability purposes. These interconnections also provided backup transmission paths. With respect to economics, if one utility had a low-cost generator, some of whose output was not needed to meet local loads, that output could be sold to the adjacent utility, which would then lower the output of its more expensive units.

The first power pool, the Pennsylvania-New Jersey-Maryland Interconnection (PJM), was formed in the late 1920s in the mid-Atlantic region. It centralized the operation of the generation and transmission resources of the utilities in this six-state area.

Beginning in the 1980s, the amount of electricity traded among utilities began to increase dramatically. Passage of the 1992 Energy Policy Act greatly encouraged such trading by bringing competition to the nation's bulk-power systems. This legislation authorized nonutility companies to build and operate power plants, and it required the Federal Energy Regulatory Commission (FERC) to ensure nondiscriminatory, open access to utility transmission systems. As of 1998, nonutility generators owned 13 percent of the nation's generating capacity and produced 12 percent of the total electricity. The amount of electricity produced by nonutility companies has almost tripled during the past decade. These independent power producers now account for the majority of new power plants.

In response to the 1992 Act, FERC issued Order 888 in April 1996, requiring investor-owned utilities to file tariffs for open-access transmission. The Order also encouraged utilities to form and join independent system operators (ISOs) to operate transmission grids and be independent of all commercial interests. Since then, several ISOs have been created in California, the Midwest, the Northeast, and Texas. For example, the California ISO is a nonprofit corporation that operates the California electric grid, most of which is owned by investor-owned utilities. The California ISO owns no generation and, therefore, acquires the generation resources it needs for reliability through either competitive markets or long-term contracts. Such generation is required to maintain voltages within the necessary ranges throughout the grid and to maintain "extra" capacity that can quickly increase output when a major generator or transmission line suddenly fails.

Because of these legislative and regulatory changes, the nation's transmission grids are used today in ways for which they were not designed. These systems were originally planned and built to connect a utility's generating stations to its load centers, and later expanded to interconnect with its neighbors. Today, these systems are used to transport power over longer distances, often across several utility systems. Both the number and complexity of these wholesale power transactions have grown dramatically in recent years, stimulated by the creation of more than 700 FERC-approved power marketers.

KEY FEATURES OF ELECTRIC SYSTEMS

Bulk-power 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 requires metering, computing, telecommunications, and control equipment to monitor loads, generation, and the voltages and flows throughout the transmission system, and to adjust generation output to match load. Generation must follow load in near-realtime because it is difficult and expensive to store electricity.
- The transmission network is primarily passive. Unlike natural gas pipelines, transmission grids have few “control valves” or “booster pumps” to regulate electrical flows; control actions are limited primarily to adjusting generation output and to opening and closing switches to add or remove transmission lines from service.

These two unique characteristics lead to four reliability consequences with practical implications that dominate power system design and operations. The consequences are:

- Every action can affect all other activities on the grid. Specifically, changes in the locations and amounts of power generated and consumed, and in the configuration of the transmission grid can affect flows throughout the system. Therefore, the operations of all bulk-power participants must be coordinated.
- Cascading problems that increase in severity are a real problem. Failure of a single element can, if not managed properly, cause the subsequent rapid failure of many additional elements, disrupting the entire transmission system.
- The need to be ready for the next contingency, more than current conditions, dominates the design and operation of bulk-power systems. It is usually not the present flow through a line or transformer that limits allowable power transfers, but rather the flow that would occur if another element fails.
- Because electricity flows at nearly the speed of light, maintaining reliability often requires that actions be taken instantaneously (within fractions of a second), which requires computing, communication, and control actions that are automatic. Two examples follow.

1 Lightning provides an example of a situation in which automatic responses are required. When lightning strikes a transmission line, breakers at both ends of the line sense the high current and open automatically. Within a fraction of a second (enough time for the problem to resolve itself), the breakers close and power, once again, flows through the line. Because this process occurs so quickly, it takes place with no human intervention.

2 Responding to a major generation outage provides another example of how the electric utility industry responds to its unique features. Figure 2 illustrates how the system operates when a major generating unit suddenly fails.

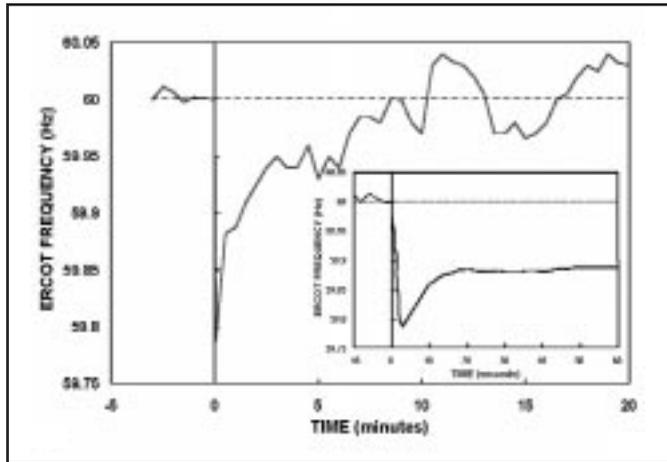


Fig. 2. Interconnection frequency before and after the loss of a 653-MW generator. The inset shows frequency for the first minute after the outage, and the larger figure shows frequency for the first 20 minutes after the outage.

Prior to the outage, system frequency is very close to its 60-Hz reference value. (Alternating current reverses direction at regular periods or cycles. The number of cycles a second is called the frequency.) Generally, within a second after the outage occurs, frequency drops. The frequency decline is arrested primarily because many electrical loads (such as motors) vary with system frequency. If the frequency decline is large enough, certain generators sense the frequency decline and rapidly increase their power output. This response accounts for the initial frequency rise during the first several seconds after the outage occurs, as shown in the Fig. 2 inset. At this point, other generating units, in response to signals from the control center, begin to increase output. More fuel is added to the boiler, leading to more steam production, which leads to higher power output. In this example, the system worked as it was intended to, and frequency was restored to its reference value within 8.5 minutes. Keeping frequency close to the 60-Hz reference is essential because (1) generators can be damaged by vibrations associated with non-reference frequencies; (2) some customer equipment performs poorly when frequency deviates from 60-Hz; and (3) frequency is an important indicator of Interconnection “health.”

RELIABILITY INSTITUTIONS

Several different types of organizations oversee, operate, and participate in bulk-power markets and reliability. These entities, some of which did not exist a few years ago, range from private companies to government agencies and include independent power producers, power marketers and brokers, transmission utilities, and retail-service providers, as well as control-area operators (often called system operators), security coordinators, regional reliability councils, the North American Electric Reliability Council (NERC), FERC, and state regulatory commissions.

The fundamental entity responsible for maintaining bulk-power reliability on a real-time basis is the control area. Control areas are linked to one another to form Interconnections, of which there are three in North America. Each control area seeks to minimize any adverse effect it might have on other control areas within the Interconnection by (1) matching its generation plus net incoming scheduled flows to its loads, and (2) helping the Interconnection maintain frequency at its reference value (60-Hz).

Today's approximately 150 control areas are operated primarily by utilities, although a few are run by ISOs. Control areas vary enormously in size, with several managing less than 100 MW of generation and, at the other end of the spectrum, PJM and California each managing about 50,000 MW of generation. Control areas are grouped into regional reliability councils, of which there are 10 in the 48 contiguous states, most of Canada, and a small portion of Mexico (Fig. 1).

As bulk-power markets become more competitive, the institutions that oversee and manage reliability and commerce are changing. Historically, only utilities or their power pool aggregations owned generation and transmission and therefore operated control areas. Within the last few years, several ISOs that own neither generation nor transmission, have taken over these functions in California, New England, New York, and the mid-Atlantic (PJM) region. Several other ISOs and Transcos are now under development. (Transcos differ from ISOs in that they own, as well as operate, transmission facilities.)

In December 1999, FERC issued Order No. 2000 on regional transmission organizations (RTOs). The Order requires investor-owned utilities to file with FERC, by October 2000, proposals for joining an RTO or an explanation of why the utility cannot join such a regional organization. (FERC has jurisdiction only over the two-thirds of the U.S. transmission grid owned by investor-owned utilities; FERC has no authority over municipal, electric cooperative, or federal utilities, nor over the investor-owned utilities within the Electric Reliability Council of Texas.)

The “higher level” bulk-power entities are changing as well. FERC is the federal agency with jurisdiction over bulk-power markets, including interstate transmission systems. Historically, FERC has not had to involve itself with reliability functions, leaving those engineering and operating issues to NERC.

Electric utilities established NERC in 1968 as a voluntary membership organization as an alternative to government regulation of reliability. NERC’s creation was a direct consequence of the 1965 Northeastern blackout mentioned previously. NERC develops standards, guidelines, and criteria for assuring system security and evaluating system adequacy (Exhibit 1). NERC is funded by the 10 regional reliability councils, which adapt NERC rules to meet the needs of their regions. NERC and the regional councils have largely succeeded in maintaining a high degree of transmission-grid reliability throughout North America.

Historically, the reliability councils have functioned without enforcement powers, depending on voluntary compliance with standards. NERC is now in the process of converting its system from one in which peer pressure encouraged compliance with voluntary standards into one in which compliance is mandatory, and violations are subject to penalties (including fines).

These changes are a necessary consequence of changes in the electricity industry, in particular, the separation of competitive generation from regulated transmission and system control. Absent federal legislation requiring compliance with reliability standards, NERC has limited ability to enforce its reliability rules.

NERC is also expanding greatly the representation from all industry sectors on its committees and the Board of Trustees; in 1999, NERC expanded its Board to include nine new members who are not affiliated with any market sector. Upon passage of federal reliability legislation authorizing creation of a national reliability organization, NERC’s industry-affiliated board members will resign, leaving a board that is entirely free of commercial interests in electricity markets. At that time, the relationship between the national and regional reliability councils will change, with the regional reliability councils reporting to the new national organization, which in turn will be responsible to FERC as *the* national reliability organization.

Exhibit 1. Reliability Terms

The electricity industry divides bulk-power reliability into two components, *adequacy* and *security*. Adequacy implies that there are enough generation and transmission resources available to meet projected customer needs for electricity plus reserves for contingencies. Adequacy deals with long-term planning and investment. Security implies that the system will remain intact even after equipment failures occur. It focuses on short-term operations.

In response to recent NERC requirements, 22 Regional Security Coordinators coordinate within the reliability regions and across regional boundaries. These security coordinators conduct day-ahead security analysis, analyze current-day operating conditions, and implement NERC's transmission loading relief procedures to mitigate transmission overloads.

Until a few years ago, FERC and NERC operated on parallel tracks with little interaction needed between the two institutions. FERC oversaw bulk-power commerce, NERC oversaw bulk-power reliability, and there was little interaction between commerce and reliability. To the extent that reliability and economics affected each other, the effects were internalized within each vertically integrated utility. Therefore, the costs and benefits of reliability actions were felt by the same parties—the utility and its retail customers. Because utilities were regulated monopolies and generally permitted to recover their costs through rates, they were willing to cooperate with each other to maintain reliability. In competitive electricity markets, cost recovery is not assured, which greatly reduces the incentives to cooperate.

Unbundling generation from transmission and creating competitive markets for electricity are dramatically changing this situation. The industry now recognizes that reliability and commerce are tightly integrated. Increasingly, FERC receives cases in which market participants complain that NERC reliability rules, their implementation, or both competitively disadvantage them. The utilities generally respond that they are, in most states, still legally responsible for serving their retail customers; because these customers paid for the transmission grid, they are entitled to first call on its use. NERC recently established a Market Interface Committee, as a complement to its long-standing Operating (Security) and Adequacy (Engineering) Committees, to deal with the interactions between reliability and commerce.

As the electricity industry continues to restructure, state public utility commissions may play smaller roles in bulk-power operations, reliability, and commerce. FERC has jurisdiction over bulk-power commerce, and the physics of electricity are largely regional and not local. While states will often seek to preserve a role for themselves in the establishment and operation of RTOs, ultimately they will likely serve more as advisors to RTOs than as regulators. They will, however, continue to oversee and approve siting requests for new generation and transmission facilities.

POTENTIAL PROBLEMS

Recently, concerns have been raised about both generation and transmission adequacy. Generation reserve margins have been declining for at least the past two decades, at a rate of almost 1 percent per year (Fig. 3). Many utilities, surprised by the dramatic increases in fuel prices and demand reductions during the 1970s, wound up with more generation during the 1980s than was actually needed, so some of the decline in generation reserve margins makes sense. Currently, reserve margins are tight in some regions of the country, suggesting that additional generation is needed soon.

While few utilities are planning to build much generation as part of their regulated rate base, unregulated utility affiliates and independent power producers have announced plans for over 100,000 MW of new capacity, more than enough to meet expected needs for the next several years. How much of this capacity will actually get built, and when, are not known. The key question here is whether competitive market forces will be sufficient to provide enough generating capacity for reliability.

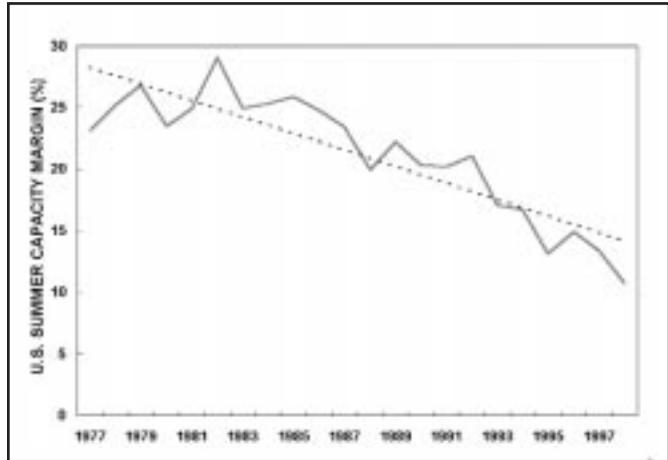


Fig. 3. Trends in the amount of “extra” generating capacity that utilities maintained during the past two decades.

One of the many uncertainties about the amount of new capacity that will materialize concerns interconnection requirements. Because of the high degree of interaction among elements on a transmission grid, it is essential that generators connected to the grid meet strict engineering and operational requirements so that their performance will not adversely affect the grid. Some independent power producers complain about long delays in gaining approval from transmission owners to interconnect, and the excessive, expensive, and inconsistent (across utilities) requirements for such interconnections. On the other hand, utilities have received many interconnection requests and are responding as quickly as they reasonably can. In addition, the utilities note that the requirements are only what is needed to ensure safe and reliable operation of the grid.

As with generation, expansion of transmission grids has not kept pace with growth in electricity demand (Fig. 4). Annual investments in new transmission (corrected for inflation) have been declining by about \$100 million a year over the past two decades. Between 1989 and 1998, the miles of transmission lines per MW of summer demand declined by 16 percent; utility projections show a further 13 percent decline in transmission capacity by 2008.

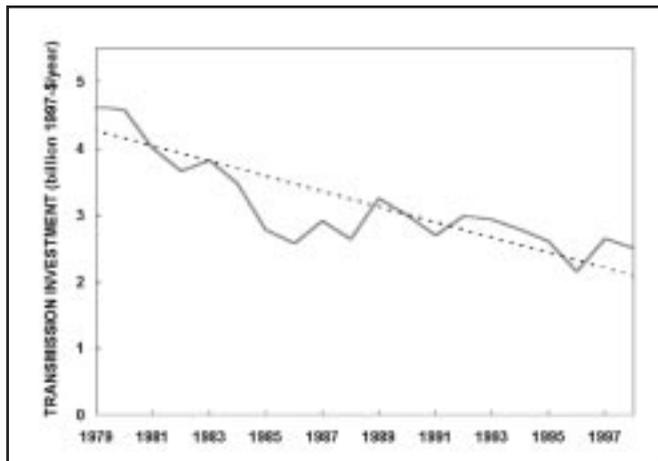


Fig. 4. Trends in the transmission investment during the past two decades.

Several forces keep utilities from building new transmission lines and expanding the capacity of existing lines, including (1) public opposition to new facilities; (2) complexity of obtaining regulatory approvals, often from more than one agency, for new facilities; (3) utility uncertainty about cost recovery given the current state of the utility industry, partly regulated and partly competitive; and (4) returns on transmission investment that may be too low to attract needed capital. In addition, as generation and transmission are increasingly separated, transmission planners know less and less, later and later, about plans for the location and size of new generating units, which further complicates transmission planning.

While wholesale electricity prices have declined on average, they have become much more volatile during the past few years (Fig. 5). Some observers view this volatility as a sign of impending trouble. Others believe that price volatility is an essential and valuable element of competitive bulk-power markets. High prices signal investors that building new power plants will likely be profitable. They also motivate the owners of power plants currently out of service to bring the units back online quickly. These prices also help some consumers (especially large, sophisticated industrial customers) determine how much electricity to consume and when.

The situation that occurred in PJM on July 6, 1999, illustrates well the benefits of price volatility. PJM's load reached an all-time high that day and, as a consequence, it deployed its active load management program to reduce demand during the mid-day hours. The program cut demand by an average of 1 percent during nine peak-load hours. Because electricity prices reached \$920/MWh during these hours, this demand

reduction cut electricity costs by \$10 million. (Were it not for these demand reductions, electricity prices would have been even higher!) This \$920/MWh price was 20 times higher than the average price in PJM between June and September 1999. Interestingly, the same electricity reduction on the following day would have saved only \$0.4 million because electricity prices on July 7 reached only \$50/MWh.

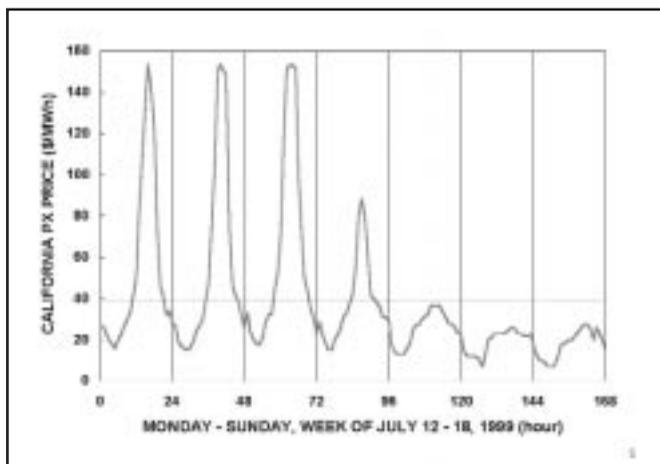


Fig. 5. Day-ahead prices in California for the week of July 12, 1999. The average price was \$39/MWh, with a range from \$7 to \$154/MWh during this week.

Although volatile electricity prices contain important information for electricity consumers and suppliers that can help maintain reliability, most consumers today continue to face time-invariant prices. For example, the price spikes that occurred in the Midwest during the summers of 1998 and 1999 affected primarily wholesale suppliers and not their retail customers. Had some customers been exposed to these high prices, they would surely have cut demand enough to reduce the magnitude of these price spikes. Even if only a small fraction of retail load faces realtime prices, price spikes would be less frequent and dramatic, and the need for additional generating capacity would be reduced.

Transmission systems are congested more frequently than they were in the past. Transmission congestion means that it is not possible to complete all the proposed transactions to move power from one location to another on the grid. Such commercial-transaction restrictions can arise because of various technical limits on transmission elements. Congestion is generally *not* related to the actual flows on lines. Congestion occurs most frequently because of contingency analysis rather than current line flows. The generation dispatch is modified because a line *will* overload *if* a specific contingency occurs (e.g., a generator or transmission line trips). Because there is often no time to take corrective action to prevent cascading failures if such a contingency occurs, it is necessary to preemptively modify the generation dispatch.

The increase in congestion is largely caused by differences in how vertically integrated utilities managed their generation resources and how independent power producers do so today. In the past, a utility would schedule and operate its generating units

so that they would not overload transmission lines, neither in normal operation nor after a contingency occurs. Any changes in generation dispatch to accommodate transmission constraints were internalized within one company, the utility.

Today, independent power producers do not know beforehand the likely condition of the transmission system and the operation of other generators on the grid. Therefore, they schedule generation without knowledge of potential congestion problems. As a consequence of this deintegration of generation from transmission and system control, system operators frequently invoke special procedures (called transmission line loading relief) to cut transactions that would otherwise overload transmission lines or render them unable to operate after a major contingency. An alternative to this engineering approach is to use locational transmission prices that permit market participants to decide whether their transactions are worth the extra cost of dealing with congestion. When congestion occurs today, the costs fall on only those market participants responsible for the congestion and are no longer shared among all transmission users.

In the long run, construction of new transmission lines and suitably located generating stations close to loads can reduce congestion. Here, too, locational prices let generation investors know where to place their new units and inform transmission planners about where to increase transmission capacity.

As U.S. bulk-power systems become more complicated, for both planning and operations, additional data and computer tools are needed. Improved load-forecasting methods, information on the status and condition of transmission equipment, and computer models to analyze the current and likely future states of the transmission system are all needed to cope with increases in the number, diversity, and complexity of market participants and transactions.

POSSIBLE SOLUTIONS

To a large extent, the problems identified above are transitional, a consequence of the fact that the electricity industry is in the midst of a major transformation. Vertically integrated utilities are unbundling (separating) their generation and transmission functions and, in many cases, are selling their generation resources. As of early 2000, 12 percent of investor-owned utility generation had been sold, and another 5 percent was for sale. Increasingly, generation is owned and managed by independent companies or unregulated utility affiliates, not by regulated utilities.

Perhaps the most important element of a long-term solution to today's reliability concerns is passage of federal legislation granting additional authority to FERC. Such authority would have two components.

- It would extend FERC's authority for reliability (but not for economic regulation) to all segments of the U.S. electricity industry. This authority would ensure that all participants in electricity markets—independent power producers, distribution utilities, transmission utilities, system operators, power marketers, and customers—play by the same reliability rules and share equitably in the costs of reliability. Currently, FERC has jurisdiction over only the investor-owned utilities operating outside of the Electric Reliability Council of Texas, which encompasses about two-thirds of the transmission facilities in the country.
- It would grant FERC the authority to approve and oversee one national electric reliability organization. This organization, likely to be based on NERC, will be responsible for developing, implementing, and enforcing mandatory reliability standards nationwide, with FERC oversight. Currently, compliance with NERC standards is voluntary, subject only to peer pressure. This new reliability organization will have the authority to delegate certain responsibilities to regional entities, with approval from FERC.

A second element of a long-term solution is continued formation of large RTOs throughout the country. ISOs operate now in California, the mid-Atlantic region, New York, New England, and Texas, and are under development in the Midwest. Other utilities are likely to form RTOs in response to FERC's December 1999 Order No. 2000. Because RTOs own no generation, they can assure market participants of unbiased treatment and nondiscriminatory access to the transmission grid. Because of their large regional scope, RTOs can better manage transmission congestion and other reliability problems than can many small, independent entities, each of which operates only a small part of the grid. Thus, RTOs hold out the promise of higher reliability and more robust competition for electricity supply.

In addition, the RTO focus on transmission and its operation may give it more incentive to build needed transmission facilities. Transcos, in particular, will have no business other than transmission and will be eager to expand and improve customer service through cost-effective expansion of transmission grids. The large regional scope and independence of an RTO should enable it to better plan for grid expansion in a way that will be more acceptable to more market participants and government decision makers.

The creation of RTOs (and the further separation of generation from transmission) should help resolve conflicts between investors in new generation seeking to connect to the grid and transmission owners. With an RTO that is truly independent of generation, the interconnection requirements are more likely to be perceived as being fair. That is, customers will not question the motivation for what may appear to be overly complicated engineering requirements for metering, switching, communications, and controls. They will likely accept the need for these conditions as essential to protect the grid because they are imposed uniformly on all generators.

More generally, we need to decide as a society how to balance the need for additional transmission investment against local opposition to the construction of such facilities. To help facilitate such tradeoffs, we need to determine who, and on what basis, decides where and when to build new transmission lines and substations. Although electric grids are regional (encompassing many states), transmission siting is currently a state responsibility. Decisions on new transmission might be more efficiently made on a regional basis, perhaps using multistate compacts operating under FERC jurisdiction. In addition, FERC needs to ensure that the investors in new transmission facilities are appropriately compensated for the risks they take. Many believe that the current returns on transmission investments are too low. FERC, in Order No. 2000, invited innovative rate proposals for transmission.

Existing ISOs have experienced many difficulties in establishing and operating real-time (hourly and intrahour) markets for energy and reliability services. Additional work is needed to minimize the amount of administrative adjustments made by ISOs, such as after-the-fact changes to market prices, imposition of price caps, and rules that determine which generators can and cannot set market prices. Customers will obtain the desired amounts of reliability services only when prices accurately reflect costs and value.

Finally, existing markets are largely one-sided, with competition among generators but no competition between the supply and demand sides of the equation. Customers, especially large, sophisticated industrial customers, should have the opportunity to face time-varying (hourly) electricity prices and to participate in reliability markets (e.g., by offering to sell load reductions as contingency reserves). As loads increasingly participate in bulk-power markets, these markets will become deeper and more liquid and, as a consequence, more efficient.

If the electricity industry and its regulators appropriately address these market and reliability problems, bulk-power reliability in the United States should improve. In addition, reliance on markets (including customer loads) to provide reliability services should lower the overall costs of maintaining a reliable electrical system.

