# Final Report

# Keeping the Power Flowing:

## Ensuring a Strong Transmission System to Support Consumer Needs for Cost-Effectiveness, Security and Reliability

CECA
Consumer Energy Council of America

A Report of
The Consumer Energy Council of America
Transmission Infrastructure Forum

January 2005

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# Acknowledgements

The Consumer Energy Council of America would like to express special thanks to the following leadership of the CECA Transmission Infrastructure Forum for their valuable service to the Forum:

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## DISCLAIMER

CECA appreciates and is grateful for the valuable assistance and thoughtful critiques provided by members of the CECA Transmission Infrastructure Forum. An attempt was made to reach consensus on as many issues as possible in this report. Nevertheless, the members of the Transmission Infrastructure Forum do not necessarily approve, disapprove, or endorse the report. CECA assumes full responsibility for the report and its contents.

**Consumer Energy Council of America**

*Transmission Infrastructure Forum*

# Letter from the Chair and Vice Chairs

January 2005

As the Chair and Vice Chairs of the CECA Transmission Infrastructure Forum, we are proud to provide this landmark report to policymakers, energy leaders, large and small consumers and the media. This report examines the issues surrounding the U.S. electric power transmission system and sets a strategy for policymakers to consider in developing transmission policies that meet the nation's future electricity needs.

As the U.S. economy grows in the next decade, there will continue to be many challenges that energy policymakers must confront. Since the transmission grid is the backbone of our nation's economy, it is vital that the system evolve in a manner that results in a robust, yet flexible system that provides consumers with reliable, stable and affordable electricity.

The key areas of focus in this report – the critical need for consumer input into transmission policy, the provision of reliable, affordable electricity by each region of the country, the need for a durable regulatory framework, the flexibility for institutional and structural options, the requirement for clear cost recovery and allocation mechanisms, the necessity for coordinated regional transmission planning, and the continued need for public/private sector funding of advanced technologies – provide benefits for consumers that we, as active participants in transmission policy, believe should be goals for all transmission policy going forward.

All regions of the country have a unique perspective on how their region operates and how best to serve their consumers. We believe this CECA report is unique in that we have evaluated all the regions on how they plan for and coordinate planning for transmission and how such processes impact the consumers the region serves.

We believe that to meet our growing need for increased electric supply in the near term, our transmission system must be able to respond to changes in demand. Therefore, where the benefits of upgrading the system outweigh the costs, we believe that it is in the consumers' best interest to make such improvements. This report outlines the various options for upgrading the transmission system, yet recognizes that every region will approach transmission enhancements differently.

We urge you to read this report. You will likely agree with some parts of the report and disagree with others. The participants of this CECA Forum also had disparate views on the details. However, all of us agree that the recommendations provided will enable greater knowledge and understanding of transmission issues and will provide policymakers with a roadmap of how to move forward to meet consumers' demands in the coming years.

This report provides you, the reader, with both the principles and the mechanisms for making sure that our transmission system remains strong, that consumers continue to be well served and that barriers to

enhancements in the transmission system are overcome. We encourage you as policymakers, industry leaders, and concerned citizens to use the policy recommendations provided as a benchmark for developing and supporting future transmission policy so that consumers will benefit.

Sincerely,

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# Executive Summary

## PART ONE: Setting the Stage

Consumers in the U.S. depend upon having access to a reliable and reasonably priced supply of electricity. The transmission grid helps provide this critical access. The Northeast Blackout of August 14, 2003 acutely demonstrated the devastating effects that a major transmission disruption can have on consumers, whether due to operational problems as was the case in this event, or inadequate transmission infrastructure. Fortunately, blackouts of that scale are rare. More typically, many electricity consumers pay the price of increasingly congested transmission systems on a daily basis. Over time the "costs of congestion" resulting from transmission system constraints can add up to billions of dollars. Relieving these constraints requires investment in the transmission system, which could be critically important when benefits for consumers outweigh the costs of such investments.

Increasing stress and demands on the transmission system are not likely to change without action by policymakers, regulators, transmission owners, and power system operators. Until the problems associated with financing, licensing, and adequate cost recovery of new transmission grid improvements are satisfactorily addressed and resolved, increasing demands on the transmission system will potentially threaten reliability, reduce the security of the system, and increase costs to consumers.

To create conditions conducive to transmission investment, reliable operations, and efficient use of the grid, policymakers and regulators, including Congress, the Federal Energy Regulatory Commission ("FERC") and state public utility regulators, must resolve policy and jurisdictional uncertainties so that there are clear rules under which decisions can be made about transmission investment, planning and operations.

Consumers bear the consequences of the lack of reliability and the costs of power associated with an inadequate transmission system. They also eventually pay the price for transmission enhancements. Therefore, consumer benefits and costs, and the distribution of costs and benefits among different sets of consumers, must be central to any assessment of transmission needs.

### *The CECA Transmission Infrastructure Forum*

This report – *Keeping the Power Flowing: Ensuring a Strong Transmission System to Support Consumer Needs For Cost-effectiveness, Security and Reliability* – provides policymakers with important information for making decisions that will support the provision of adequate transmission services to meet future consumer needs. It is the result of the deliberations of the Consumer Energy Council of America's (CECA) Transmission Infrastructure Forum – a group of the nation's preeminent electricity and transmission experts, practitioners and policymakers – who worked throughout 2004 to develop policy guidance. As the nation's senior public interest energy policy organization with a 30-year history of bringing stakeholders together to find solutions to contentious energy policy issues, CECA is uniquely qualified to develop and make recommendations to policymakers on transmission investment solutions in the best interest of consumers.

The goal of the CECA Transmission Infrastructure Forum was to assess what could – and should – be done to ensure that the electric transmission system serves as a reliable backbone supporting the delivery of electricity services for consumers. Guided by the consumer priorities established by

consensus of members of the CECA Forum, the Forum analyzed trends in transmission investment, planning and operations policies and practices, and opportunities for applications of advanced transmission-related technologies. The CECA Forum focused its attention on relatively near term issues that could be addressed in the next decade.

### *Structure of the Report*

This report is organized into three parts:

***Part One*** sets the stage for why CECA undertook this intensive examination of transmission issues. Chapter One outlines the purpose and the goals of the CECA Forum, describes the process it utilized, and summarizes its recommendations. Chapter Two further frames the issues by defining a set of national consumer priorities that formed the basis of the CECA Forum's deliberations. Chapter Two also describes the historical background of the U.S. bulk power system and discusses recent economic and policy changes that have affected the grid.

***Part Two*** analyzes the state of the U.S. transmission system and the implications for consumers of actions to upgrade and modernize the grid. Chapter Three addresses whether the continuation of transmission investment trends will lead to a grid infrastructure that is adequate to ensure a reliable and economic transmission system. Chapter Four examines transmission planning and operations practices and procedures on a regional basis and how they affect consumers. Chapter Five examines the impacts on consumers of changes to the grid, including the deployment of advanced technologies.

***Part Three*** offers the CECA Forum's public policy recommendations. Chapter Six lays these out, with the intention of assisting policymakers in their task of making policy to ensure that the electric power transmission system meets consumers' needs for high quality, affordable, and reliable power in the future.

### *CECA Recommendations*

The CECA Forum's recommendations constitute an action plan that CECA believes will result in cost-effective operation and maintenance of, and enhancements to, the transmission system to meet increasing end-use consumers' demands on the system. As discussed in the report, the CECA Forum has made recommendations in seven areas that are key to the development of a robust transmission system that can respond flexibly to future consumer needs in a cost-effective manner, thus producing benefits for consumers over the long term. The detailed recommendations begin on Page xxxv of the Executive Summary. The seven areas are:

- ☑ **Consumer Input** to transmission policy development is critical to ensure that consumer needs are taken into account in transmission planning and operations, notably with respect to important issues such as the need, location and cost of new transmission facilities.

- ☑ Consumers want **Reliable Electricity** at stable and affordable prices. Transmission owners and operators must be held accountable for compliance with established, clear and enforceable reliability standards and best transmission planning and operations practices.

- ☑ A clear, consistent and durable **Regulatory Framework** is needed to provide transmission owners and investors with the guidance they need to make investment decisions that will benefit consumers.

- ☑ **Institutional and Structural** options, such as independent system operators and regional transmission organizations, should be explored and, where appropriate, implemented to improve planning and operations and reduce long-term costs to consumers. The appropriate institutional, structural and organizational form(s) will vary by region given their different histories, industry structures, and regulatory policy

preferences.

- ☑ **Cost Recovery and Allocation** mechanisms for transmission-owning utilities and other transmission providers must be developed to remove disincentives for investment in transmission to ensure that timely and cost-effective investments in both reliability and economic upgrades will be made – and made efficiently and in a way that ensures consumers are treated fairly and equitably in cost-recovery policies now and over time.

- ☑ **Regional Transmission Planning** is needed to ensure the development of a robust transmission system capable of responding flexibly to changes (e.g., in fuel prices and availability) to meet consumer needs reliably and at reasonable cost over time. Regional transmission planning must address inter-regional coordination, national security requirements and environmental concerns, in addition to system-related needs.

- ☑ Finally, policymakers, regulators, transmission owners and the electric industry must look to the future and make a long-term commitment to provide **Public/Private Funding for Advanced Technologies** that can enhance transmission system performance in the near term and provide value-added services and benefits for consumers in the long term.

### *History of the U.S. Bulk Power System*

The evolution of America's transmission system follows the outlines of the overall development of the electric industry as a whole. Transmission *lines* were originally built to interconnect electric generating stations with the local wires that distributed power to consumers so that power from distant power plants could serve the customers. Transmission *systems* linked small power systems together to improve reliability and reduce costs. The networking and aggregation of small systems into larger and larger interconnected areas has helped to produce cost savings over many decades of the 20th Century. Along with these cost savings, rapid advances in power plant technology also reduced costs.

The passage of the Federal Power Act and the Public Utility Holding Company Act in the 1930s to regulate price and industry structure established a regulatory framework where utility rates were based on costs to serve consumers, with an allowed return on investment. This regulatory and industrial model worked well for utilities, regulators and consumers as long as electric utilities were a declining cost industry. However, over time, things began to change. The Great Northeast Blackout of 1965 revealed weaknesses in the design of the interconnected transmission system. The North American Electric Reliability Council ("NERC") was established as a voluntary organization of electric utilities to improve, coordinate and set standards for the planning and operation of regional power grids. Also, by the mid 1960s through late 1970s, utility system costs were no longer declining – for many reasons, among them the greater amount of capital required for larger coal and nuclear power plants; the capital investment required for additional transmission to interconnect these larger central station generators to distant loads; and the slowing of demand growth due to higher rate increases, in part from the recovery of these large capital additions as well as fuel price increases following the oil price increases in 1973 and 1978/79 due to the OPEC oil embargo. As the decades progressed, increasing environmental and power plant safety regulations (in the period following the Three Mile Island nuclear accident) also imposed costs on the utility industry.

In this context, high electricity rates and the effects of oil and other perceived fossil fuel shortages drove Congress to pass the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the Power Plant and Industrial Fuel Use Act. PURPA, and the federal and state regulations implementing it, led to the growth of non-utility generation suppliers. At the same time, advances in power combustion technology from military research and development were made available to the power industry, leading to the advent of gas-

fired combined cycle power plants, with lower capital costs, higher efficiencies and reduced environmental impacts compared to other technologies.

These conditions created substantial economic, policy and political pressure on the then-existing structure of the industry, in which traditional vertically-integrated utility companies owned generation, transmission and distribution facilities to serve consumers. States with high power costs turned to market forces as a way to control power production costs, with the expectation that competitive pressures and innovative models for power plant development, financing, construction, and operations would spur more efficient power production over the long run as compared to the traditional cost-plus utility framework. These changes laid the foundation for policy changes that led to the evolving industry structure.

The development of competitive power producers also had implications for the operation and use of the transmission system as well as for transmission policy. While policy and technological innovations helped to enable the opportunity for competition in the generation of electricity, these non-utility power plants could only compete practically if they had access to and use of monopoly transmission facilities owned, controlled and operated by utility companies. These complex wholesale power market conditions created pressure for regulators to address the terms and conditions of access to and use of transmission facilities that had been built and regulated for other purposes in the past.

### *Structural, Economic, Institutional and Policy Changes Affecting the Transmission System*

In 1992, Congress passed the Energy Policy Act ("EPAct"), making it possible for competitive power producers to be entitled to access and use utilities' transmission systems. These requirements put new demands on utilities' transmission planning and operations. In 1996, FERC issued Orders 888 and 889, taking another step toward the development of a competitive wholesale market policy, leading to the formation of independent system operators ("ISOs") in California, and parts of the Northeast (PJM [Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia]). The planning and development of ISOs in Texas, the Midwest and the Southwest, with varying degrees of centralized coordination of transmission operations and planning, and control of operations, followed these ISOs.

At the same time, many state regulators and legislatures began to examine retail competition – allowing end-use consumers to choose their electricity suppliers directly – in part to further extend benefits from competitive wholesale markets to retail consumers. Retail access in turn introduced the possibility of new demands on the transmission system. For example, competitive power producers interested in serving retail consumers wanted to use the transmission system to reach their customers, and many electric utilities and other non-utility power companies obtained authority from FERC to sell power in wholesale markets at market-based rates, and also needed transmission access to do so.

These arrangements increased the complexity and the levels of demands on transmission system planning and operations, and exacerbated pressures to clarify and modify the terms under which different parties paid for and had the right to use existing and new transmission capacity. In addition, problems with nascent ISO operations and governance began to emerge under the strain of actual market operations, particularly in the area of interregional coordination (i.e., so-called "seams" problems).

In December 1999, FERC issued Order 2000, encouraging transmission owners to turn over the operation of their transmission assets to independent Regional Transmission Organizations ("RTOs"), which would operate the transmission system and perform other related services as well. In FERC's view, an RTO would be better able to support competitive wholesale electricity markets

and respond to emerging concerns about the adequacy of the transmission system.

During the same time period (2000-2001), the California electricity crisis and the Enron scandals came to light. Many policymakers, regulators, consumers, and market participants lost faith in the ability of competition in the electric industry to deliver benefits to consumers. These events halted any further movement toward retail competition in the states that had not by then adopted it, and led many states and regions to revisit and adjust their plans for progress toward wholesale competition.

Around the same time, FERC issued its proposed Standard Market Design ("SMD") rulemaking. This proposal would have RTOs administering not only transmission service but also centrally organized wholesale markets. FERC saw SMD as a way to standardize markets across the country, end discrimination in transmission access and create economic efficiencies. Many states and utilities, particularly those located in relatively low-cost regions in the South and West, strongly opposed FERC's vision of a standardized national market. In the face of this opposition, FERC has clarified that individual regions may follow their own paths to competitive wholesale electricity markets.

Throughout this period, various policymakers, legislators and regulators have called for comprehensive federal energy legislation to address a host of energy issues including those associated with electricity. The 108th Congress failed to pass a comprehensive federal energy bill and did not enact a stand-alone reliability bill, even though it was supported by many in the wake of the August 2003 Blackout.

During the expansion of competition in wholesale electricity markets over the last decade, there has been growing concern about the adequacy of the transmission infrastructure to meet new demands placed on it by new uses of the transmission system – expanded bilateral contracts, interconnection of new types of generators with different ownership structures, increased power flows across regions, coordinated operations across interconnected regions, and trading or exchanges of power between parties. Concerns about the adequacy of the transmission system came to a head with the August 2003 Blackout. These trends and events make it clear that the continued ability of the transmission system to meet increasing consumer needs will be at risk unless policymakers and transmission system owners and operators act to address the new complexities and challenges facing the system due to changing circumstances and these increasing demands.

## PART TWO: Analysis of the Current Transmission System

### Current Trends in Transmission

The CECA Forum's review of the state of the U.S. transmission system reveals increasing stresses, which vary by region and which have implications for consumers if these trends continue over the next decade.

#### *Current Transmission Functions, Organizational Structure and Technology*

The transmission system will continue to serve multiple, simultaneous functions in the electric power system, in addition to its traditional reliability functions. These traditional functions include:

- meeting NERC and regional reliability council reliability requirements;
- providing voltage support and other attributes to assure that the electric system functions reliably in real time;
- ensuring that the outputs from a utility's generation can be transported to its own customers;
- reducing the required investment in generation by allowing the industry to capture economies of scale through larger generating plants providing service to a broader geographic area;
- reducing generating capacity reserve margins

required to reliably serve consumer load; and
- supporting reliance on remote generation sources located closer to fuel sources (e.g., coal, hydro and renewable energy).

The transmission system is now expected to perform new functions as well. These new functions have developed in response to and to accommodate new participants in the electric industry, adding to the complexity of utility system planning and operations, including:
- providing competitive power producers with equal access to the grid;
- facilitating the entry of new power producers into the market;
- providing generators and suppliers with access to multiple markets;
- enabling mechanisms for reliably handling transmission congestion; and
- reducing problems tied to the potential exercise of local generation market power.

The two main business models for ownership of transmission in various parts of the nation are: (1) separate ownership and control of transmission where the control functions are handled by a system operator, and transmission assets are owned by other entities; and (2) joint ownership of transmission assets and control of the grid within a single vertically-integrated entity.

While a number of new advanced transmission technologies are under development and some are in the early stages of commercialization, the existing transmission system is not expected to undergo dramatic technological change in the next ten years – in large part due to transmission policies that do not support such investment.

### *Transmission Investment, Maintenance and Planning*

Viewed from many dimensions, support for the transmission system is in decline. Adjusted for peak demand, transmission investment has dropped over the past few decades, although the rate of decline has slowed. Transmission investment is expected to remain at an historically low level of about $3 to $4 billion per year over the next decade. Some view this level of investment as adequate to meet reliability needs, but insufficient to relieve transmission constraints and meet economic needs. Similarly, transmission maintenance expenditures and employment levels have declined over the same period. Expenditures for transmission maintenance have declined at a rate of one percent per year since the passage of EPAct in 1992. Further, employment in various categories of electric utility workers is projected to decline over the 2002 to 2012 period. While some of these decreases may relate to improved efficiencies in transmission system operations, declining transmission maintenance and employment levels can affect reliability and the ability of the transmission system to serve consumers.

Transmission planning occurs in different ways in different parts of the country. In most regions, transmission utilities undertake their own planning studies, sometimes in coordination with one another. In a vertically-integrated utility setting, utility planning usually determines the need for specific facilities to be built – including both transmission and generation. In regions with ISOs and RTOs, the regional transmission provider also carries out transmission planning and analysis. These efforts are subject to a mixed set of federal and state regulatory policies, sometimes resulting in conflicting policy directives affecting individual transmission providers and in uncertainty and mixed incentives (and some disincentives) for transmission investment.

### *Impacts of Cost Recovery Policy on Transmission Investment*

Uncertainty about the terms under which transmission investment may be recovered – not only timing and amount of investment recovery, but also the allocation of costs among affected parties – stands as a major barrier to new transmission investment. This is particularly true where transmission enhancements are needed for economic purposes. By contrast, where transmission investment is needed to address reliability issues, there tends to be greater support for the view that end-use consumers served by the affected utility will benefit broadly from the upgrades, so

that "socialization" of the costs among a broad range of consumers seems acceptable. For certain economic upgrades, however, it is sometimes argued that the specific beneficiaries of the upgrade must pay. When a specific generator seeks transmission service and is asked to pay up front for related transmission investment, this is known as "participant funding." When the beneficiaries of an investment are viewed more broadly – for example, as all consumers in a particular location – this funding method is referred to as "beneficiaries pay." Both approaches tend to produce reluctance in some regions to invest in transmission, which can threaten reliability and lead to increased electricity prices for consumers in congested areas.

## *Impacts and Implications for Consumers*

Assuming the continuation of current trends over the next decade in transmission investment, transmission planning and operations, consumers will be impacted by a variety of benefits and costs. The CECA Forum examined these impacts and implications along four dimensions:

- **Reliability** (e.g., frequency of actions needed to avoid lines being overloaded, increased risk of blackouts);
- **Economics** (e.g., overall electricity price impacts, price volatility, congestion, exposure to the price effects of the exercise of market power, greater access of purchasers of power to a larger set of suppliers);
- **Environment** (e.g., siting impacts, air emissions impacts from power plants given a certain configuration of transmission and generation assumptions); and
- **Security** (e.g., exposure of the critical infrastructure to terrorist attack).

### *Reliability Impacts and Implications for Consumers*

Following the trend of the past decade, electricity demand is expected to continue to increase (especially in Texas and parts of the Southwest and the South), with the grid continuing to be heavily loaded over more hours of the day and year. In many geographic areas, the number of single or multiple operating contingencies that could create serious problems has increased and is expected to continue to do so into the next decade. Operating the grid at higher loadings will continue to mean greater stress on equipment, a smaller range of options, and a shorter period of time for dealing with unexpected problems. In addition to reliability concerns, congestion impacts can be expected to increase.

For consumers, the reliability implications of the continuation of these trends are significant, though they may not be immediately evident. While operational pressure may be the immediate symptom of any reliability problems resulting from the downward trend in investment in the system, the increasing reliance on operator actions to manage a heavily loaded grid through an assessment of potential contingencies means that there is a diminished ability to respond to system emergencies. Therefore, consumers in certain regions will be exposed to greater risk of involuntary supply disruptions for reasons other than weather.

### *Economic Impacts and Implications for Consumers*

The continuation of low levels of transmission investment exacerbates the likely economic consequences for the long term, resulting in potentially severe consequences for consumers. Short-run surpluses of generation resources (primarily gas-fired generation) exist in many regions of the country, which put downward pressure on power production prices. However, these same surpluses lead to lower market prices for power producers and put financial pressure on owners of resources such that they are unable to finance additional investments or maintain credit for ongoing operations, with potentially negative long-term consequences. This continued financial pressure – along with regulatory, political and institutional uncertainty over investment recovery prospects in both transmission and in generation markets – increases the concern that generation and transmission investment will not be made at

levels necessary to meet future load growth. Further, the electric industry's increasing reliance on natural gas, which has demonstrated high price volatility and significant overall price increases in the last few years, contributes to higher and more volatile electricity costs to ultimate consumers, (as well as adding to the financial pressure on owners) and places further stresses on the bulk power system not anticipated just a few years prior. All of these factors also affect the health of the nation's economy, which is highly dependent on electricity.

There can be economic consequences of transmission congestion for consumers in the form of higher cost power and possibly reduced reliability. Some of these consumer costs come in the form of "congestion costs" – i.e., costs related to running higher cost power plants as a result of the inability to access lower-cost power reliably due to transmission constraints. In some cases, consumers do not feel the direct effects of such costs – at least in the short run – due to the imposition of rate caps, rate freezes, and "transition-period" rates, which have accompanied the introduction of retail choice in many states that have pursued restructuring. As transition rate freezes and rate caps begin to expire in coming years, consumers may directly face more of these costs.

### *Environmental Impacts and Implications for Consumers*

Environmental impacts are directly and indirectly tied to electricity generation and transmission. Environmental impacts of power generation fall into two principal categories: emissions (most notably air emissions) and localized siting. Major air emissions of $SO_2$ and $NO_x$ have decreased over the past decade, with further decreases possible in the future with the adoption of new air emission regulations. $CO_2$ emissions are expected to continue to increase, due in part to increasing generation output with emissions not subject to caps. Additionally, while not examined directly by this CECA Forum, energy facility siting processes and politics are likely to continue to be difficult, time-consuming and controversial – whether for new transmission facilities, new gas pipelines to meet demands of new power plants for gas, new combined-cycle or peaking projects, or wind turbines in offshore waters.

Particularly if emissions reduction programs are not implemented, consumers in those regions of the country that are not in attainment with EPA air emissions limits will continue to be exposed to the public health effects of air pollution resulting from these air emissions from the electric power sector. Coal-fired generation, in particular, is expected to remain high and to contribute especially to emissions of greenhouse gases related to global warming. While the direct impacts of climate change are not readily visible in the short term, the implications for consumers are negative over time.

### *National Security Impacts and Implications for Consumers*

To the extent that the transmission system is operating closer to its technical limits than it has in the past, it may be less able to respond in the event of a national security threat in the future. The need to be able to manage the consequences of a possible security threat adds to these demands. Current transmission investment trends do not always accommodate a significant amount of new investment in areas such as improving inventories of transformers and other critical equipment or in adopting technologies such as system monitoring (e.g., SCADA system elements) that could improve system security, whether on a routine round-the-clock basis or in response to an actual security threat.

Since U.S. consumers rely on electricity for virtually all underlying functions of the economy – from telecommunications, to banking, to traffic systems, to air traffic control systems, to medical systems – those consumers' quality of life would be severely disrupted if electricity service were unavailable for an extended period of time as a result of terrorist events. Protecting against the possibility of widespread and prolonged disruptions of service will require investment to enhance the transmission system and changes in

practices for purchasing and maintaining inventories of critical components. The tradeoff for consumers involves balancing the cost of these investments against the likelihood and consequences of a security threat. Costs to upgrade the system represent an insurance policy against the harm from such unlikely events.

## *CECA Findings on Current Trends in Transmission*

With these trends in mind, the CECA Forum's findings support the conclusion that policymakers, regulators, and transmission owners and operators must act now to ensure that the transmission system will be maintained and, where necessary, enhanced in a manner that will make it robust enough to continue to meet reliability standards, changing consumer needs, continuing operational challenges and to respond to national security threats. A strong transmission system is a key link in the critical infrastructure system of the nation.

### *Findings on Reliability Impacts*

In some regions, consumers will have reliable electricity supplies, consistent with the levels experienced in the past. However, during high demand periods and in some geographic regions, the risk of involuntary disruptions will increase, as the system is operated closer to the margins of reliable and safe operations. In those regions and in load pockets where the system is operating close to its reliability margins, these conditions may not typically be visible to consumers, but uses of electricity at certain times (e.g., hours, seasons) may be more vulnerable to disruption, power quality problems and higher costs in light of these conditions on the grid.

### *Findings on Economic Impacts*

Costs of electricity service will continue to differ regionally. In general, consumers in the areas that now enjoy relatively low electricity prices (e.g., parts of the South, parts of the Pacific Northwest, the Midwest and Rockies) will continue to do so compared to other areas (e.g., the Northeast and California) that do not have access to low cost supplies. In regions with higher prices resulting directly and indirectly from transmission-related bottlenecks or constraints, consumers will have less access to economical sources of power on the constrained side of transmission boundaries. These consumers may not be paying for new transmission investment but they are paying higher prices for electricity supplies. In these instances it may be less costly to relieve the transmission bottleneck. The economic attractiveness of relieving the constraints will vary by local circumstances.

### *Findings on Cost Allocation*

Even where there may be a net gain to society, there are winners and losers as a result of transmission investments in terms of impacts on electricity costs, siting-related impacts, and impacts on electricity rates. Where there is a misalignment between the real or perceived beneficiaries of new investments in transmission and those who pay the direct or indirect costs of these investments, there will continue to be resistance to making and/or allowing cost recovery for such investments.

### *Findings on Coordination of Gas, Coal and Other Generation Fuels with the Electricity Systems*

Overall coordination of information about gas resources and supply delivery systems with electricity system operations, including understanding the impacts of fuel prices and availability, is essential in order to avoid risks of major electric power interruptions, and must be taken into account in transmission system planning. Similarly, systems that rely heavily on other sources of generation must plan for possible disruptions in those supplies, e.g., systems reliant on hydroelectric generation must plan for the consequences of drought.

## ***Transmission System Planning and Operations***

The CECA Forum analyzed practices and policies for regional transmission planning and operations. Effective regional transmission planning is critical to the maintenance of a robust transmission system. Consumer input early in the transmission planning process is important to ensure that consumer needs are met and to increase the likelihood that transmission projects that provide benefits to consumers will enjoy local support.

### *Scope of Analysis*

The CECA Forum conducted research and analysis of transmission planning practices in two types of regions. (1) those with the organized markets – ISO-New England ("ISO-NE"), the New York ISO ("NYISO"), PJM Interconnection ("PJM"), the Texas wholesale market operated by the Electric Reliability Council of Texas ("ERCOT"), and the nascent Midwest ISO ("MISO"); and (2) those areas without organized markets – Florida Reliability Coordinating Council ("FRCC"), the Southwest Power Pool ("SPP"), the Southeastern Electric Reliability Council ("SERC"), and the Western Electricity Coordinating Council ("WECC").

Based on this analysis, the CECA Forum identified common themes important to consumers and attempted to identify both best practices and deficiencies in approaches to transmission planning, and operating rules and practices. There are considerable regional differences, more so with respect to planning than operations. In particular, the transmission planning process differs from regions with centrally organized wholesale markets, to regions in which the vertically-integrated utility model has persisted, to regions where some combination of the two are developing. Generally, the transmission planning process tends to be more transparent and allow for more consumer input at an earlier stage in the centrally organized markets; however, even across the regions with centrally organized markets, there are significant differences in planning practices. The biggest differences relate to the extent to which, and how, the planning process considers upgrades for economic as well as reliability reasons. Regions also vary according to the manner in which transmission planners, providers, and owners take into account "non-wires" options – recognizing that these options are complements to and not substitutes for transmission in many instances.

### *Planning*

The most salient regional differences in transmission planning practices pertain to coordination and responsibility for transmission planning, treatment of reliability versus economic upgrades, regulatory roles, consumer input, and cost recovery and allocation.

#### The Regulatory Role in a Multi-State Context

State and federal regulatory policies and frameworks, including planning requirements, cost recovery and siting authority, affect transmission planning and investment. Uncertainty about their respective jurisdictions can hinder timely action on transmission enhancements that benefit consumers. Interstate coordination of transmission planning is a challenge for every region, with the possible exception of ERCOT, which is electrically isolated from the rest of the grid and lies completely within the borders of one state. To ensure that the integrated transmission grid is planned and built in a manner that advances consumer interests overall, policies that establish an appropriate balance between local and larger interests need to be developed and clearly articulated and adopted by all states involved. Regional State Committees ("RSCs") offer a great potential benefit if they provide an avenue for moving forward on a multitude of transmission issues. To do so, RSCs must develop and continue efficient processes for resolving interstate differences and not simply add a layer of required intervention that makes consumer participation more difficult.

### Consumer Input to the Transmission Planning Process

Consumers' ability to have meaningful input into the transmission planning process is critical for ensuring that their views are taken into account in decision-making about the need for and benefits of transmission enhancements. The ability of consumers to participate in the transmission planning process varies by region. Having the opportunity to participate in planning processes does not guarantee the ability of consumers to participate effectively in these processes, however. To be effective participants in the transmission planning process, consumers must have both access to the process and adequate information and analytic capabilities at their disposal. The opportunity to participate on advisory committees may be rendered meaningless unless these provisions are also in place. The CECA Forum found that consumers generally have more frequent and earlier opportunities to provide input in the regions with centrally organized markets, where the transmission planning processes are generally more transparent.

### Regional Coordination

Coordinated regional planning is important for meeting consumers' needs given the interconnected nature of the transmission grid. The CECA Forum's examination of transmission regions found that in general the current or newly emerging organized markets, including ISO-NE, PJM, ERCOT, and, to a lesser extent, NYISO and MISO, have relatively coordinated planning processes, as compared to the type of planning that takes place in SERC, SPP, and FRCC, where it occurs mostly within vertically-integrated utilities. With some notable exceptions, such as the Southern Company and Entergy Corporation systems in SERC, the geographic footprints of the vertically-integrated utilities tend to be smaller than those of the organized markets. Also, in the WECC, the Southwest Transmission Expansion Plan ("STEP") process involves representatives from the California ISO and adjacent control areas. The new Seams Steering Group-Western Interconnection Planning Working Group ("SSG-WI PWG") has also developed a process for identifying transmission projects with broad regional benefits.

### Planning for Economic and Reliability Upgrades

In the transmission planning process, distinctions between reliability and economic upgrades tend to be less notable where utilities remain vertically integrated and traditionally regulated with planning processes that address both types of upgrades. Transmission planning processes in organized markets tend to distinguish between economic and reliability upgrades and address them in separate analyses and processes. Economic upgrades are transmission improvements made primarily to reduce power production costs, without necessarily being required to maintain reliability standards. Reliability upgrades are investments in the transmission system required to ensure that reliability standards are met or that quality service to customers can continue uninterrupted. As load grows and the system changes (e.g., generating units are retired or added), a transmission constraint that initially resulted in higher power costs to consumers may grow to the point where operational adjustments are no longer adequate to ensure reliability, resulting in the need for a reliability upgrade. Consequently, in some instances, the difference between economic and reliability upgrades may be primarily one of timing – today's economic project becomes tomorrow's reliability project.

One strand of the policy debate suggests that when the projected costs of transmission constraints exceed the cost of relieving them, a market participant will step in to make the needed investment. This market-based approach depends on consumers as well as potential transmission investors receiving accurate price signals (e.g., through locational marginal pricing) about the real-time, location-specific costs of congestion. For multiple reasons, price signals, however accurate, may not provide sufficient incentive for the market to respond. Consequently, market-based approaches may not provide adequate

incentives for investment in economic upgrades, and therefore may need to be supplemented with regulatory approaches. There is increasing recognition that the transmission provider's planning process may need to serve as a critical "backstop" when the market fails to produce needed investment, i.e., investment that is less costly than the congestion costs that it eliminates. Several of the organized markets have developed or are in the process of developing planning processes for economic transmission upgrades.

#### Transmission Cost Recovery

Rules for cost recovery, including both federal and state regulations and the transmission pricing rules of specific organized markets, clearly affect the willingness of transmission investors to propose and build new projects. Consumers benefit when cost recovery rules provide appropriate incentives to transmission owners and investors to plan for and build transmission facilities in a timely fashion for both reliability and economic purposes when the benefits exceed costs. Where the traditional, vertically-integrated utility model predominates, the cost-of service model, with its comparative certainty of cost recovery, generally prevails. Transmission service rates are also cost-based in regions with centrally organized markets, where costs typically recovered through either "postage stamp" rates (which recover total embedded transmission costs through a uniform charge applied to every unit of load served on a given system) or "license plate rates" (designed to recover the costs of a given transmission owner through charges levied on the end users served by that transmission owner, rather than the system as a whole). Further, in organized markets based on locational marginal pricing, entities which build transmission, including interconnecting generators, may recover some of their costs through market mechanisms, such as Financial Transmission Rights ("FTRs"). FTRs entitle their holders to revenues resulting from the difference in energy prices between two different locations. Locational prices can provide appropriate price signals about where new transmission investment is needed, but the magnitude of most transmission and generation projects may be sufficiently large to change locational marginal prices, making it difficult to rely on FTRs as an adequate cost recovery mechanism.

#### Transmission Cost Allocation

Cost allocation policies determine which consumers pay for transmission enhancements. The issue of cost allocation is one of the most hotly debated transmission topics in policy circles today. Funding mechanisms range from "participant funding" to "beneficiaries pay" to "socialization" of costs. Clearly, consumers are affected by cost allocation policies and will be concerned about whether they are being treated fairly and equitably under any particular allocation method. Both the character of and lack of clarity about cost allocation policies also indirectly impact consumers because such policies affect incentives for transmission investment. When cost allocation policies are unclear, transmission owners and investors may be reluctant to commit funds for improvements that will provide economic benefits to consumers, and may even hesitate to make needed reliability upgrades. Further, cost-allocation mechanisms that spread costs more broadly to consumer beneficiaries are typically viewed as providing transmission owners with greater assurance of cost recovery. Many regions are in the process of developing "default cost allocation" mechanisms for transmission expenditures to provide clarity with respect to allocation policy. Even if clear cost allocation principles are developed in multiple regions, tensions among state and federal regulatory policy with respect to cost allocation and cost recovery will affect incentives for transmission investment. Regulators may be unwilling and/or unable to commit in advance to default cost allocation criteria, and state regulators in particular often perceive an obligation to review projects on a case-by-case basis.

### *Operations*

The August 2003 Blackout and its causes dramatically demonstrated the impact on consumers of utility system operations. As the transmission

system is increasingly stressed, operators will face greater challenges as they work to ensure the reliability of the system.

For several decades, system operations have taken place in the context of a set of voluntary reliability standards established by NERC. NERC is an association of ten regional reliability councils, whose members in turn include the transmission providers and users in the U.S., Canada and a portion of Northern Mexico. Transmission providers have committed to follow NERC's standards and, in some cases, even more rigorous regional standards. The standards pertain to a variety of operations and maintenance practices encouraged by NERC through a combination of voluntary commitments, public disclosure, peer pressure, and auditing.

NERC has adopted a "Functional Model" that identifies reliability and other functions performed by market participant regardless of the prevailing market structure or regional differences. The model is being used to develop standards that provide clear accountability for reliability responsibilities over a wide variety of market structures and industry organizational models with emphasis on performance. These standards apply to such things as: real-time system operations, as carried out by control area operators; real-time monitoring, involving various tools and data to evaluate system conditions on a continuing basis; emergency operations, based on advanced emergency plans and protocols; near-term operational planning, involving coordination of outages of generation and transmission facilities; training and certifications for operators of the grid; enforcement and compliance of reliability standards, which in the absence of federal legislation authorizing mandatory compliance with NERC rules, involves peer pressure, voluntary compliance, performance-based metrics, and contract-based compliance approaches; and coordination of operations of interconnected transmission systems.

## *CECA Findings on Regional Transmission Planning and Operations*

The CECA Forum reached several findings related to transmission operations and planning. First, it is clear that to ensure adequate investment in the nation's transmission infrastructure, the entity ultimately responsible for transmission planning must be identified and held accountable. It must have the authority to mandate investment if necessary. Similarly, with respect to ensuring reliable transmission operations, the entity responsible for monitoring and enforcing compliance with reliability standards must be given clear authority to do so.

### *Findings on Consumer Participation in the Planning Process*

Consumers benefit from the opportunity to provide timely, meaningful input into the transmission planning process. Whether the planning process is formal or informal, consumers must be given an effective role in which their views are taken into account. This will require that consumers or their representatives be provided with adequate information and that they have the capability to analyze and use that information. At the same time, the planning process should be structured such that the good of the whole is properly weighed against individual costs and interests, and so that individual stakeholders who oppose new transmission enhancement projects that benefit the system and consumers as a whole cannot be allowed to unduly delay or exercise veto power over particular projects.

### *Findings on Compliance with NERC Standards*

Consumers and the overall economy of the nation benefit when the power stays on. NERC has been instrumental in developing protocols for the safe and reliable planning and operation of

the bulk electric power system. There are a variety of organizational configurations of reliability coordinators and control area operators within and across organized markets, traditional vertically-integrated utility frameworks, and hybrids of the two. Whatever their organizational form, the management of transmission system planning, operations and maintenance must comply with national, regional and local reliability standards.

### *Findings on Coordination Among State Regulators*

Many issues related to transmission planning, such as siting, resource adequacy, and cost allocation, cut across state lines. Coordination and consensus among state regulators, through properly structured RSCs or other entities, may facilitate the resolution of these issues, contribute to regulatory certainty, and foster investment.

### *Findings on Regulatory Certainty with Respect to Cost Recovery and Allocation*

Consumers overall will benefit from additional cost-effective transmission investment. Transmission investment will not take place when the rules for cost recovery and allocation are unclear, when provisions for cost recovery are uncertain or inadequate, or when the process for determining cost allocation is unduly contentious. Clearly articulated and durable regulatory policies for cost recovery, which provide assurances that investors will have a reasonable opportunity to recoup their investment, will generate support for such investment.

### *Findings on Regulatory Oversight of Transmission Operations, Maintenance and Investment*

Violations of NERC operating protocols are punished through the threat of legal liability, peer pressure and other non-monetary sanctions largely implemented at the regional level. As formal regulation of transmission operations is introduced, more innovative "carrots and sticks" regulatory mechanisms should be developed to encourage utilities to improve transmission operations and maintenance practices and to efficiently and cost-effectively expand the transmission grid where warranted. Under any such regulatory framework, policies should be adopted which clearly specify the goals to be met, the performance metrics to measure their achievement, and the method for allocating benefits actually achieved between consumers and transmission owners.

### *Findings on Strategic and Coordinated Regional Transmission Planning to Assure Reliability*

The interconnected nature of the transmission grid requires coordination of transmission planning and operations across regions. Consistent with the long-lead times and potentially substantial costs of transmission investment, transmission planning should be forward-looking and strategic. It should take into account the wide array of resources that are likely to be available – including remote generation resources, such as mine-mouth coal, wind power and other alternative energy resources, as well as new transmission facilities, load-center generation, nuclear power, distributed generation, demand response, energy efficiency, and new advanced transmission-related technologies.

### *Findings on Planning and Cost Allocation for Economic Upgrades*

The regional transmission planning process should address economic, in addition to reliability, upgrades. The entity responsible for regional transmission planning should identify the need for an economic upgrade using clearly defined criteria, including a comparison of projected benefits and costs, under different fuel price scenarios. Rules and procedures for determining who should pay for economic upgrades should also ensure that investors are given appropriate incentives to make such upgrades, and the reasonable opportunity to recover costs that are prudently incurred.

## *The Impacts of Changing Demands on the Transmission System*

In addition to considering the implications for consumers of the continuation of current trends in transmission investment, planning and operations, the CECA Forum examined the consequences for consumers of the changing demands on the transmission system that could result from changes in a variety of factors affecting the utilization of the transmission grid, including such variables as: fuel prices and availability; generation additions and retirements; increased consumer demand (due to greater than expected economic growth and new uses of electricity); or decreased consumer demand due to increased energy efficiency and wider deployment of distributed generation; and changes in public policy.

### *Fuel Prices and Availability*

If natural gas and oil prices remain at high levels, an immediate effect on the electricity system would be that changes would occur in the dispatch of generation, with resulting changes in power flows on the transmission system as these units can be more expensive to operate. High levels of natural gas and oil prices could also lead to a shift in the generation mix toward coal and wind. Depending on the location of these plants, the shift from natural gas to coal and wind could lead to increased demand on the transmission system. New coal plants, particularly mine mouth coal, and wind generators are generally located remotely, requiring additional investment in transmission and/or increasing constraints on the existing grid.

The case can be made that higher electricity prices will increase incentives for energy efficiency and distributed generation which, if substantial, will lead to reduced demand on the transmission system. However, it is not clear yet whether renewable distributed generation technologies other than wind power will achieve the unit-cost reductions needed to make them cost-effective even with high natural gas prices. Higher-than-expected natural gas and oil prices and concerns about air emissions and climate change have also created renewed interest in nuclear energy.

### *Generation Additions and Retirements*

Generation retirements and additions that differ from expectations, in terms of magnitude and locations, will affect the transmission system. Retirements can increase congestion on the transmission system where older units are located in load pockets or areas that already face transmission constraints. If these older units are needed to maintain reliability, their owners must be compensated for their costs of operation, increasing electricity prices to consumers. Retirement of significant generation could also affect transfers of power between regions.

### *Changes in Consumer Demand*

The most likely driver of increased electricity demand would be economic growth at a rate higher than expected. Increased economic growth is more likely to be seen in some regions – e.g., the South and Southwest – than in others such as the Northeast and Mid-Atlantic. These patterns of electricity growth could increase inter-regional constraints and transmission congestion adding to the stress on the transmission system.

Consumer demand for increased power quality and reliability could also grow as more and more sensitive technologies are used in a variety of industries, commercial applications and even at the residential level. The impact on the transmission system will depend on how this demand for power quality is met. To the extent that consumers demand higher quality power from their utilities, additional investments at both the distribution and transmission levels are likely to be needed to meet this demand, and could be significant. Alternatively, consumer load could grow more slowly than expected due to increases in electricity prices, reductions in the costs of energy efficiency and distributed generation technologies, and wider implementation of load management programs.

### *Policy Changes*

Clarification of the policy uncertainties, and in some cases adoption of policy reforms, could remove disincentives to investment in transmission and resources that would benefit consumers.

#### National Energy Legislation

Comprehensive national energy legislation that includes an electricity title is uncertain as of the publication of this report. The 108th Congress made strides toward passing a comprehensive energy bill which dealt with many issues addressed in this report. Nonetheless, the legislation failed because of controversies other than the electricity title. National legislation that clarifies the respective roles of FERC and state regulators with respect to electricity market frameworks and transmission planning, and mandates compliance with reliability standards and establishes the authority of FERC to enforce those reliability standards could lead to additional investment in transmission enhancements.

#### Transmission Jurisdiction/Regulatory Treatment of Cost Recovery and Allocation

If jurisdictional issues are resolved and federal and state regulators set forth clear policies for recovery of cost-effective transmission investments for economic upgrades, then these investments could proceed over the next 10 years of the CECA Forum's study period as well. Clear cost allocation and recovery policies for both reliability and economic upgrades would facilitate investment in transmission enhancements (including operations and maintenance) required to support critical infrastructure needs, improve service to consumers, maintain or increase reliability, and minimize costs.

#### Other Regulatory Policies

A number of other regulatory and utility policies not directly related to transmission also affect utilization of the system. For example, policies regarding interconnection of distributed generation and standby and backup rates can facilitate or discourage consumer interest in distributed generation and in turn affect demands on the transmission system.

Environmental policy and regulation will affect fuel choice and the generation mix, which will impact the transmission system. The design of environmental regulations can also affect pressures on transmission systems by changing the relative cost of power produced at different power plants. If compliance with environmental regulations requires or hastens the closure of large coal plants, interregional power transfers will be affected and this could potentially increase congestion and/or reduce reliability. Changes in environmental regulations with respect to disposal of hazardous and other waste products (e.g., municipal solid waste, wood) could also affect the future generation mix, but the effect is likely to be small.

#### Tax Credits and Subsidies

Tax credits and subsidies will affect investment in different types of generation, which in turn will affect demand on the transmission system. For example, renewable energy production credits were reinstated in the fall of 2004 and are expected to cause the level of wind development to increase. Remotely located wind installations may increase the need for transmission to connect them to load centers.

## ***CECA Findings on Changing Demand***

### *Findings on High Electricity Demand Implications*

A high electricity demand growth scenario could occur from a combination of such factors as economic rebound above expected levels; unexpected and rapid policy clarification that assures appropriate investment recovery of transmission enhancements and lowers the costs of long-distance transmission; and lower than expected natural gas prices which would enable many of the newer gas plants to be dispatched with greater

frequency. The combined effect of these impacts would be felt in the regions of the country that have a large amount of manufacturing and are growing – i.e., the South and the Southwest. From a transmission perspective, a high electricity demand growth scenario would increase pressure on demand for transmission service into and within those regions where growth occurs. Increased demand could threaten reliability and increase costs to consumers if required or economic transmission system enhancements are not undertaken in the near term.

### *Findings on Low Electricity Demand Implications*

Conversely, lower than expected electricity demand could occur, for example, from a combination of such factors as very high natural gas and oil prices, lower than expected economic growth (that might result in part from high fuel prices), and higher electricity prices due to high fuel prices, particularly in the Northeast. The combined effect of these impacts might be increased power flows from coal areas to gas areas (e.g., from the Midwest to the Northeast and from the Rocky Mountains to California and Arizona) and congestion in areas of the Northeast (within and between regions). Therefore, while slow demand growth would most likely relieve demand for transmission, the factors that led to slow demand growth might have countervailing effects. If transmission investment is not sufficient to enable the grid to handle the potential consequences of these changing power flows, consumers will face the risk of reduced reliability and higher costs.

Slower than expected demands on the electric grid could result from other trends, as well. The introduction of new integration technologies for utilization and recognition of demand response could also affect the *shape* of power loads. There could be less on-peak demand for a given amount of economic growth. This could occur, for example, if homes in the fast-growing Sunbelt where demand is driven by air conditioning were equipped not only with efficient air conditioners, but with smart thermostats that raised the temperature of the house a few degrees when conditions warrant, or when the homeowner specified. These new approaches could allow a distribution network to be built with far lower, and flatter, demand profiles than the typical American home is designed for. Italy, for example, is installing 30 million interval meters in all homes and driving towards per-household demand not-to-exceed 2kW. Although that may be an aggressive goal for the typically more energy-intensive American household – especially within the time frames analyzed in this CECA Forum – the right combinations of efficient, responsive and integrated appliances could significantly lower and flatten demand curves.

### *Findings on Implications of Changes in Demands on Transmission*

The factors influencing transmission utilization can change in unpredictable ways. The impacts will vary depending on the type and magnitude of changes and by region due to different industry organizational structures, regulatory frameworks, resource availability and costs of power. Therefore, it is of critical importance to consumers that policymakers focus their attention on weaknesses in the transmission system as revealed in the CECA Forum's analysis of trends in investment and practices in planning and operations. These weaknesses demonstrate the value of consumer input, the need for regulatory certainty and clear cost recovery and allocation policies to remove (or reduce) barriers to investment, and the critical importance of robust transmission planning, particularly to address critical infrastructure needs, in order to ensure that changing consumer demands are met with reliable transmission service at reasonable cost.

## ***Advances in Technologies – Opportunities for Consumer Benefits***

There are a wide variety of advanced transmission-related technologies, in various stages of development, the deployment of which could improve the operation of the transmission system, thereby alleviating existing and increasing

stresses and thus improving reliability, and reducing costs for consumers. Many of these technologies offer the promise of greatly increased efficiencies in existing grid utilization, the ability to use the transmission system in new ways, reduced costs, and reduced environmental impacts. Some new transmission technologies will enable the more effective application of other technologies, such as distributed generation and demand response options. Other technologies enable real-time monitoring that will not only improve system use, but will also increase the ability of operators to detect security threats affecting the critical electricity infrastructure.

Most of these advanced technologies are still in early stages of development and will not be widely available until well beyond the CECA study period. These technologies will require significant RDD&D to achieve their potential benefits for consumers. While the benefits of most of these advanced transmission technologies will not be realized for consumers in the near term, commitment to significant funding of RDD&D is needed now in order to deliver on technology's promise in the future. The CECA Forum's review of advanced technologies reinforces its earlier findings that barriers to required or economic transmission investment must be overcome, whether for investment in conventional transmission enhancements and operations or for advanced technologies.

### *CECA Findings on Advanced Technologies*

#### *Findings on Research Development, Demonstration & Deployment Funding*

Government and private industry support for long-term funding of RDD&D is needed to ensure that advanced transmission-related technologies can achieve their potential to deliver benefits to consumers in terms of enhanced reliability, lower costs, reduced environmental impacts, and the availability of a greater variety of value-added services.

#### *Findings on Policy and Regulatory Support of Advanced Technologies*

Federal and state policymakers and regulators should encourage the deployment of advanced technologies that are cost-effective today and new ones as they become cost-effective by implementing policies that clarify the conditions under which the costs of these technologies can be recovered. These conditions should require an analysis of consumer costs and benefits, and consumers should only be expected to pay for those technologies that are shown to be cost-effective in the long term.

## PART THREE: Moving Forward

The purpose of the CECA Transmission Infrastructure Forum was to examine steps that need to be taken to ensure that the U.S. transmission system meets consumer needs over the next decade, the time period of the CECA study. The CECA Forum identified a set of consumer priorities for a robust transmission system, analyzed issues and trends affecting transmission requirements, and ultimately developed a set of recommendations to guide the actions of policymakers. These recommendations call for immediate and near term actions and articulate principles to guide future policy development. These recommendations provide an action plan for policymakers that will help to ensure that the physical infrastructure of the transmission system is maintained in a way that assures reliability and that supports economic transactions – whether in a traditionally regulated market or in a competitive market framework.

The seven areas addressed in the CECA Forum's action plan are the following: Consumer Input; Reliability; Regulatory Framework; Institutional/Structural Reforms; Cost Issues; Regional Transmission Planning; and Public/Private Funding of Advanced Technologies.

## Consumer Energy Council of America

*Transmission Infrastructure Forum Recommendations*

### *Recommendations for Consumer Input*

- FERC, the U.S. Department of Energy, state utility regulators and policymakers, regional transmission planning entities and the electric utility industry (and its related industries) should undertake efforts to educate the public, including local and municipal officials and electricity consumers generally, about the critical role that the transmission system plays in ensuring that consumers are supplied with reliable power under a variety of scenarios at the lowest possible cost to meet their the electricity service needs. Consumer education efforts should be directed toward enhancing consumers' understanding of how the transmission system, in conjunction with generation and distribution, affects the electricity services they receive, and how these services relate to their own economic and social well-being, as well as that of the national economy.

- FERC, state utility regulators, and the entities responsible for transmission planning should require that transmission planning processes provide consumers with an opportunity to participate in the early stages and throughout such processes so that their input will be most effective. One means of enhancing consumer participation in transmission planning processes would be to ensure adequate funding of state consumer advocate offices and to encourage the further development and identification of other consumer groups or representatives with sufficient institutional foundation and longevity to maintain a level of education on electric power delivery issues (including generation, transmission and distribution) that enables them to participate effectively in such processes.

- FERC and state utility regulators should require that transmission planning processes – whether in organized markets, traditional vertically-integrated utility frameworks, or hybrids of the two – include provisions to ensure the availability of adequate information and analysis to consumer representatives so that consumers have the opportunity to participate meaningfully in the transmission planning process. As applicable, regional transmission planning entities should consider waiving or lowering membership dues for consumer representatives where such dues present barriers to consumer participation.

### *Recommendations Related to Reliability*

- To ensure that consumers are provided with reliable transmission service to meet their changing demands, Congress must pass legislation either as part of comprehensive national energy legislation or as stand-alone legislation that provides NERC, or an equivalent independent electric reliability organization, with the authority to establish mandatory reliability standards and

monitor and enforce compliance with such reliability standards, including the ability to impose meaningful penalties for violations of reliability criteria. Enforcement should also occur at the regional level subject to FERC oversight. Such legislation should allow for more stringent regional or local reliability standards where regional or local grid configurations and conditions require them to maintain system reliability. Given the interconnected and international nature of the grid, the legislation should support the development of mandatory reliability standards that will apply to the entire North American transmission grid to assure that the grid can operate effectively and reliably to the benefit of all consumers.

- Until federal legislation is enacted to provide an independent electric reliability organization with authority, FERC and state utility regulators should work with NERC and the regional reliability councils, and their counterparts in Canada and Mexico to ensure compliance with NERC and regional reliability standards, using their existing regulatory authorities so that consumers are assured that the grid is being operated in compliance with reliability standards. In particular, FERC and NERC should continue their efforts to make reliability standards more specific and enforceable. State utility regulators should continue to monitor and enforce local transmission and distribution reliability requirements. FERC, NERC and state utility regulators should make sure that non-compliance violations are made public so that consumers can be aware of such violations.

- To ensure its independence and effectiveness, NERC, or another equivalent independent electric reliability organization, should be funded by all users of the bulk power system on a fair and equitable basis. The reasonableness of such costs should be reviewed by FERC through a public process.

- As recommended by the U.S-Canada Power System Outage Task Force Report of April 2004, RTO/ISOs, transmission owners and other load serving entities responsible for transmission operations and maintenance should coordinate operational policies and practices and encourage industry utilization of "best practices" for operations and maintenance – including increased system operator training, more sophisticated system operation tools, better vegetation management, and increased situational awareness by system operators – to ensure reliable operation of the system to meet consumer needs.

### *Recommendations for the Regulatory Framework*

- Congress should enact legislation that clarifies the respective roles of FERC and state utility regulators with regard to oversight of transmission investment, planning and operations, and siting. Any such legislation must direct federal land management agencies to simplify, clarify and set strict time lim-

its for the siting process for transmission facilities on federal lands; it should also encourage state legislators and regulators to seek changes in state laws, if necessary, that would allow states to coordinate and address siting issues in a timely manner and on a regional basis, as appropriate. Congress should recognize that the roles of federal and state regulators may vary across regions given different industry organizations and market structures so that consumers will be assured the transmission system is planned and operated in the most efficient manner to meet their needs.

- FERC and state utility regulators should encourage the development of effective regional institutions, where appropriate, to facilitate (1) consensus in a manner that reduces uncertainty; (2) coordination and implementation of all aspects of transmission planning and plans within and between relevant geographic regions, and (3) avoidance of duplication of efforts so that transmission plans can be implemented in a timely and transparent manner. To the extent possible, FERC and state utility regulators should give due consideration to the recommendations of such regional institutions, and in so doing ensure that their existence does not constitute another layer of regulation or an additional forum.

### *Recommendations for Institutional/Structural Reforms*

- FERC, together with state utility regulators, should consider the establishment of independent transmission organizations (e.g., RTOs) where they do not yet exist, or other organizational structures that may be appropriate, taking into account regional characteristics, benefits and costs, to provide cost-effective, efficient, independent administration, oversight, planning and operation of the transmission grid to meet consumer needs.

- FERC and state utility regulators should establish policies that do not favor one model over another, as long as the models provide cost-effective, efficient, independent administration, oversight, planning and operation of the transmission grid to meet consumer needs. FERC and state utility regulators should clarify the roles of various organizational structures (i.e., independent transmission companies ["ITCs"], merchant transmission companies, and transmission owned by existing vertically-integrated companies) to enhance cost-effective and reliable options for investment in the grid so that all efficient, reliable, and cost-effective service options are provided to consumers.

- FERC and state utility regulators should establish policies to ensure the existence of independent processes or institutions (where not already in existence) with the authority and accountability to implement regional transmission plans so that new transmission that benefits consumers by maintaining the reliability, adequacy and security of the system is built in a timely and cost-effective manner.

### *Recommendations Related to Cost Issues*

*Cost Recovery:*

- FERC and state utility regulators should promulgate clearly defined policies and rules for cost recovery of transmission investments and expenditures by entities subject to their respective jurisdictions in order to facilitate investment in the transmission infrastructure needed to ensure reliable service for consumers at reasonable cost. FERC and state utility regulators should ensure that cost recovery policies and rules are based on a durable regulatory framework that provides a reasonable opportunity to recover prudently incurred costs for transmission investments and expenditures associated with owning, operating and maintaining the transmission system to meet reliability needs, demonstrated long term cost-effective economic upgrades, critical infrastructure investments, and research, development, demonstration and deployment that produce clear benefits for consumers, while ensuring just and reasonable rates for consumers.

*Cost Allocation:*

- FERC and state utility regulators should establish clearly defined policies and rules for allocating transmission costs in order to facilitate timely investment in both reliability and economic upgrades that are demonstrated to be cost-effective to provide consumers with reliable service at reasonable cost.

- To ensure that costs are equitably assigned to various classes of consumers, FERC and state utility regulators should specifically address issues of cost allocation and distributional equity, i.e., how to balance benefits to the system as a whole against the potential for any unreasonable intra- or interregional cost shifting that could occur. In any cost allocation process, regulators should:

  — Recognize regional differences and historical transmission planning and cost allocation processes, and the transmission priorities established through these processes;

  — Recognize and take into account the fact that beneficiaries of a particular transmission investment can change over time; and

  — Ensure that existing consumers are not allocated costs unreasonably where the industry structure has changed or is changing (e.g., shifts to organized energy markets, etc.).

*Performance-Based Incentive Regulation:*

- FERC and state utility regulators and policymakers should recognize that

traditional cost-based regulation of transmission may not necessarily provide sufficient incentives to achieve superior operating results or to efficiently expand the transmission grid to maximize the benefits to consumers. Accordingly, FERC and state utility regulators should consider establishing carefully crafted regulatory mechanisms that provide incentives for the efficient operation, maintenance, and expansion of the transmission grid. Regulators should implement regulatory mechanisms with symmetrical penalties and opportunities for rewards. These mechanisms should encourage strict adherence to accepted transmission operations and maintenance practices that comply with NERC reliability standards by providing for monetary penalties or other sanctions for transmission owners/operators for poor performance so that consumers are assured the system is operated and maintained efficiently, and by affording transmission owners/operators the opportunity to share in the net benefits that result from their superior performance.

- FERC and state utility regulators and policymakers should ensure that regulatory mechanisms establish clearly defined and transparently reported performance metrics that relate to outputs that consumers value (e.g., efficiency, costs), reflect superior performance, do not result in unintended consequences, encourage owners/investors to pursue the lowest cost options and advanced technology options where there are demonstrated benefits to consumers. These regulatory mechanisms should provide incentives to transmission owners/investors to improve operations and maintenance practices and/or expand the grid in the most cost-effective manner. The net benefits that result from superior performance should be shared between consumers and transmission owners in an equitable fashion. There are a number of ways in which the sharing of net benefits can be accomplished, including explicit earnings sharing mechanisms, rate freezes and price caps.

### *Recommendations for Regional Transmission Planning*

- Given the interconnected nature of the grid, coordinated transmission planning should take place on a regional basis, recognizing that such regional planning processes may vary considerably across regions with different industry organizations and market structures. FERC and state utility regulators should identify the entities that are responsible for transmission planning (e.g., RTOs/ISOs, vertically-integrated utilities and other transmission owners/operators) and that are accountable to consumers and regulators for ensuring that necessary transmission facilities – for both reliability and economic purposes – are (1) identified through a transparent process that includes meaningful input from consumers early in that process, (2) constructed in a timely manner to ensure reliable, adequate and secure electricity service for consumers, and (3) designed to meet NERC reliability standards for planning and operations. The entities responsible for regional transmission planning should be cognizant of neighboring regions, of the fact that regions will evolve and their boundaries will change, and of the need for inter-regional coordination.

- Because consumers require a transmission system that is secure from natural, cyber and physical threat, the entities responsible for transmission planning and operations, in conjunction with the Department of Homeland Security and the Department of Energy, should expedite and coordinate ongoing efforts to include national security or physical and cyber-security considerations in their planning for transmission at the earliest stages of the planning process.

- The entities responsible for regional transmission planning should ensure that the planning process includes a mechanism whereby decisions that are needed to enable transmission projects to move forward can be made in a timely manner in which individual interests can be considered fairly along with the broader public interest.

- The U.S. Department of Energy should undertake a periodic (e.g., every 10 years) National Power Survey – similar to those conducted in the past – to facilitate regional planning processes that form the basis for developing future transmission plans and policies. The Department of Energy should engage the expertise of ISOs/RTOs and other regional transmission coordination entities.

- Oversight of regional transmission planning and coordination is the primary responsibility of NERC and the regional reliability councils, however FERC should have oversight responsibilities. State utility regulators and any regional institutions should be involved in the regional transmission planning process early so that public policy considerations with respect to region-wide synergies and efficiencies can be achieved and to coordinate the transmission planning process with policymakers' views of the region's long-range generation and demand resource needs.

- Regional transmission planning processes should take a broad view of the system, including taking into account local plans, future needs, operations of interconnected regions (including North American cross-border issues), retirements and additions of generation within regions, the development of non-wires options, fuel price levels and volatility, fuel availability, environmental impacts, and their potential effects on transmission operations and constraints so that consumers are provided cost-effective service at reasonable prices. Regional transmission planning should also take into account the role of transmission investment in mitigating market power by providing access to a greater number of options for meeting consumers' electricity service needs.

- Because of the importance of cost-effectiveness to consumers and the effects of the production and delivery of electricity services on the environment, regional transmission planning processes should take into consideration the development of resources that can affect transmission system utilization and the need for additional transmission. These resources include demand response, distributed energy resources, generation built on the constrained side of transmission bottlenecks, and energy efficiency options and other

"non-wires" solutions, recognizing that these resources may or may not be satisfactory substitutes for transmission and that they will affect the need for and the costs of transmission investment.

- So that consumers' needs for reliable, adequate and secure service are cost-effectively met, the entities responsible for transmission planning should enhance and implement transmission planning processes that address the need for reliability upgrades and opportunities for demonstrated, long term, cost-effective economic upgrades (that meet the needs of consumers and can be appropriately distinguished from reliability upgrades). These entities should ensure that the transmission planning process leads to a transmission system that has the ability to respond flexibly to future changes in the electricity system that are likely to occur, such as fuel prices and availability, and to future changes in consumer demands on that system. Particularly, in organized markets with a process intended to elicit market-based transmission investment, the entities responsible for regional transmission planning should develop a process that describes what and how steps will be taken to ensure that the necessary investments are made if the market does not offer a solution to the need for an identified reliability or economic upgrade. The transmission planning entities should take into account the fact that market participants will naturally want to wait for someone else to build and pay for these upgrades if this appears likely (or such provisions make it a near certainty) and should ensure that the process to respond to market inaction minimizes the likelihood of this result.

- So that consumers in the United States and bordering nations receive reliable, secure transmission service, FERC and appropriate state utility regulators should explore a cross-border cooperative approach to evaluate the need for investment in transmission enhancements required for reliability, and where cost-effective, economic purposes, and where a need is identified, encourage such investment. Such cooperation could include assuring effective participation of Canadian and/or Mexican entities in regional transmission planning processes and streamlining or otherwise improving the efficiency and timeliness of the siting process for the construction of cross-border transmission facilities.

### *Recommendations for Public/Private Funding of Advanced Technologies*

- Congress should make a long term commitment to adequately fund RDD&D of advanced transmission and related technologies, which complements private sector initiatives (by the electric utility and related industries) a key element of any national energy legislation, in order to explore and develop the potential of advanced technologies that enhance the operations of the transmission grid, improve the reliability, security, and safety of the grid, and reduce costs, thus providing benefits to consumers both during this period of transition and in the long term.

- If Congress is going to continue to influence energy policy through tax credits and subsidies for various technologies, it should clarify the policies related to transmission- and electricity-producing technologies so that investors can make rational resource decisions, and provide consumers with the benefits of implementation of advanced technologies that result in increased efficiency of the grid. Any such credits and subsidies should be made available to all for-profit and not-for-profit entities on a comparable basis.

- FERC and state utility regulators should encourage the wider deployment of existing cost-effective advanced transmission technologies that will enhance the reliability and reduce the costs of the transmission system for consumers' benefit over the long term.

- FERC and state energy policymakers should explore opportunities for cooperation with bordering nations for both investment in advanced transmission technologies and transmission RDD&D – either through government programs, industry support, or government-industry partnerships – to provide consumers with the benefits of the efficiencies that would result from such cooperation.

## Conclusion

Reliable electricity service is a necessity of modern life. Recent events, including the August 2003 Blackout, have demonstrated the potential costs to consumers of a transmission system that may not be strong enough, resilient enough, or operated well enough to provide them with reliable electricity supplies at reasonable costs. The CECA Transmission Infrastructure Forum concludes that uncertainties with respect to electricity market structures, industry organization, and cost recovery and allocation policies are hindering investment in transmission to support demands on the system and to ensure the system's ability to respond flexibly to future demands. Unless action is taken now, the quality of electricity service to consumers is likely to decline, undermining reliability and increasing costs to the detriment of consumers' well-being.

# PART ONE: SETTING THE STAGE

Chapter 1

# U.S. Consumers Depend Upon a Reliable and Robust Electric Transmission System

## An Overview of the Current Transmission System

Consumers in the U.S. depend upon having access to a reliable and reasonably priced supply of electricity. The Northeast Blackout of August 14, 2003[1] acutely demonstrated the devastating effects that such transmission disruptions can have on consumers, whether due to operational problems as was the case in this event, or inadequate transmission infrastructure. The August 2003 Blackout, caused by a sequence of events affecting the transmission systems serving a substantial portion of the U.S., disrupted power to homes, manufacturers, urban centers, transportation, communication networks, and other network industries such as water and banking, all of which require reliable power. The cost of the August 2003 Blackout has been estimated to be between $4 and $10 billion.[2]

Fortunately, blackouts on the scale of the August 2003 Blackout event are rare. More typically, there are subtle but important stresses on the transmission grid and its users. Many electricity consumers pay the price of increasingly congested transmission systems on a daily basis. In some cases, aging infrastructure designed for yesterday's power requirements, combined with growing user demands and other stresses on the distribution system, contribute to power disruptions and power quality problems on the distribution system, whose costs to the U.S. economy are estimated to be $120 billion a year and growing.[3] In others, constraints on the transmission system mean that it is relatively costly to serve local consumers, because their power supplier cannot get access to lower cost, but more remote, generation. Over time the "costs of congestion" resulting from such transmission system constraints can add up to billions of dollars.[4] In particular cases, expensive power can cause energy-intensive industrial operations to relocate abroad.[5] Relieving these constraints requires investment in the transmission system, which could be critically important when benefits for consumers outweigh the costs of such investments.

Increasing stress and demands on the transmission system are not likely to change any time soon without action by policymakers, regulators, transmission owners, and power system operators.

Nationwide, electricity demand continues to grow at a rate of approximately two percent per year.[6] Over the next decade, the ratio of transmission capacity to peak demand is expected to continue to decline.[7] Until the problems associated with financing, licensing, and adequate cost recovery of new transmission grid improvements are satisfactorily addressed and resolved, increasing demands on the transmission system will potentially threaten reliability, reduce the security of the system, and increase costs to consumers.

Policy changes are needed in parts of the country to encourage a wide variety of transmission improvements. According to the U.S. Department of Energy's *National Transmission Grid Study ("DOE Grid Study")*,[8] uncertainty over control and ownership of transmission facilities is

tending to chill innovation and investment, resulting in poor operations, reduced reliability and higher electricity costs for consumers.

Taking action today does not only mean constructing new transmission lines where they are needed.[9] Actions to create conditions that will encourage investment in transmission where it is needed are necessary, where such investment improves reliability and reduces power costs. Also, actions are needed to support effective regional transmission planning that addresses the needs of consumers and to ensure compliance of transmission system operations with reliability standards. Such actions should include review of the overall grid design, recognition of environmental and national security concerns, and consideration of efficiency measures and technology advances that improve the capability of the existing system. Such a comprehensive approach to transmission system enhancement will ensure that the transmission system works to the benefit of consumers.

*Given that consumers will ultimately pay transmission costs in one form or another, consumers' interests must be given priority consideration in any process to determine whether the transmission system needs to be enhanced.*

Specifically, new investment in transmission may involve, in some instances, construction of new lines to move power over longer distances. In other instances, it may support new technologies that enhance the efficiencies and capabilities of the existing grid infrastructure. Additionally, transmission owners and operators must undertake enhanced planning which considers regional power flows and power market opportunities in neighboring regions. Transmission operators must comply with clear and enforceable reliability standards.

To create conditions conducive to transmission investment, reliable operations, and efficient use of the grid, policymakers and regulators, including Congress, the Federal Energy Regulatory Commission ("FERC") and state public utility regulators, must resolve policy and jurisdictional uncertainties so that the rules under which they will make decisions about transmission investment, planning and operations are clear. These rules not only influence actions of transmission companies but also those of other power companies and users as well.

Who will pay the costs for these transmission upgrades? Uncertainty regarding who will pay for the upgrades to the system is, according to the Secretary of Energy's Electricity Advisory Board ("EAB"),[10] one of the central challenges that undermine transmission infrastructure development. This question, however, is only part of the "who pays" inquiry. The August 2003 Blackout made it clear that the "cost of transmission" also encompasses the impacts of a failure to invest – that is, the outages or other power reliability problems that result from inadequate transmission investment or lack of planning and operations that lead to lost productivity, loss of public services, negative impacts on health and public safety, and severe lifestyle disruption.

Tough questions face policymakers and other parties in the electric industry in determining whether and when to make investments. One key question involves determining whether a particular investment is cost-effective: that is, do its benefits to consumers exceed its costs? An increasingly difficult additional question focuses on which consumers pay what costs: is it possible to identify those consumers who benefit from a particular transmission upgrade and assign its costs to them?[11] Will these same consumers remain the beneficiaries over time, or are other consumers affected as well? Are there reliability advantages from an upgrade such that all consumers in a region benefit from the investment – and therefore all consumers should pay for it (i.e., should the costs be "socialized")? As long as questions like these remain unanswered or

unclear, even cost-effective transmission investments may not be made, due to these uncertainties over "who pays."[12]

Given that consumers will ultimately pay transmission costs in one form or another, consumers' interests must be given priority consideration in any process to determine whether the transmission system needs to be enhanced. Consumers bear the consequences of the lack of reliability and the costs of power associated with an inadequate transmission system. They also eventually pay the price for transmission enhancements. Therefore, consumer benefits and costs, and the distribution of costs and benefits among different sets of consumers, should be central to any assessment of transmission needs.

## The Purpose of the CECA Transmission Infrastructure Forum

With the August 2003 Blackout as a backdrop, there is a continuing urgency to address transmission grid enhancements and develop solutions for meeting the needs of the system. The issue was on the radar screen of the Consumer Energy Council of America ("CECA") well before August 2003. In 2002, CECA launched the Electric Industry Restructuring Forum, a public policy forum that addressed ways to achieve an optimal electric power delivery system that meets consumers' needs. The Forum produced its final report in April 2003, entitled, *Positioning the Consumer for the Future: A Roadmap to an Optimal Electric Power System.*[13] The report concluded that the lack of investment in the transmission system in some instances in some regions will result in an inability to meet the growing requirements of electricity consumers. As a result of that finding, policymakers asked CECA to address the fragility of the aging transmission infrastructure and recommend solutions that could gain broad support and provide public benefits.

As the nation's senior public interest energy policy organization with a 30-year history of bringing stakeholders together to find solutions to contentious energy policy issues, CECA is uniquely qualified to develop and make recommendations to policymakers on transmission investment solutions in the best interest of consumers. CECA launched its Transmission Infrastructure Forum ("CECA Forum") in early 2004. CECA invited the nation's preeminent electricity and transmission experts, practitioners and policymakers to serve as members of the CECA Forum.

This report is a direct result of the expert analysis and input supplied by that expert group of participants and provides policymakers with important tools for making policy decisions that will support the provision of adequate transmission services to meet current and future consumer needs.

## The Goal of the CECA Transmission Infrastructure Forum

The goal of CECA Transmission Infrastructure Forum was to assess what could – and should – be done to ensure that the electric transmission system serves as a reliable backbone supporting the delivery of electricity services for consumers. In particular, the CECA Forum focused on a series of transmission-related issues: (1) the need for future transmission system enhancements to ensure a robust system capable of responding to changing consumer demands, due to a variety of underlying factors including fuel prices; (2) the impact on consumers of the continuation of current trends in transmission investment; (3) the role of planning in ensuring an appropriate transmission system to meet consumers needs; and (4) how consumers might be affected in the near term by such developments as the deployment of advanced transmission technologies.

After nearly a year of analysis and deliberation, led by John Derrick, Chair of the CECA Forum and former Chairman of the Board of PEPCO Holdings, Inc., the Forum resulted in a series of public policy recommendations that are intended to help to guide decision makers at both the federal and state level about how to structure and operate the grid. The CECA Forum focused its attention on relatively near term issues that could

be addressed in the next decade. Specifically, the CECA Forum explored options to enhance the transmission system that could be implemented in the next five to 10 years and would have a 10 to 20 year impact, recognizing that efforts over the longer term will also benefit consumers. While the CECA Forum considered transmission siting issues to be important, siting was considered to be outside the scope of this particular Forum.

This report presents the CECA Forum's recommendations along with a thorough examination of transmission system needs. It also provides background on the evolution of the U.S. transmission system to assist the reader in understanding the context for the CECA Forum's analyses and recommendations.

In developing the recommendations in this report, members of the CECA Forum recognized that jurisdictional tensions between state and federal authorities over transmission issues will continue for the foreseeable future. Complex and important transmission policy issues rest at the intersection of state and federal responsibilities, with different state and the federal policymakers having different perspectives on what should be done to resolve transmission problems.

Resolution of these federal/state jurisdictional tensions is unlikely to be found in the near term. Nonetheless, the CECA Forum believes that such resolution of these conflicting jurisdictional issues should – and must – be achieved. The nation's electricity consumers need to be able to rely on a transmission system that meets their needs – reliably, safely and economically. The CECA Forum resolved that this objective must be met, and can be met in ways that reflect the differences among the various regions of the United States. Consistent with this, the CECA Forum did not attempt to prescribe a single plan or model for the electric power transmission system that should be applied in all parts of the country. Rather, the CECA Forum recognized that the differences among states and regions of the nation warrant different approaches to solving the nation's important transmission challenges.

To guide policymakers, the CECA Forum identified key consumer priorities that must be considered in any effort to transform the U.S. transmission system to meet the needs of consumers in the 21st Century. No matter what changes occur in industry structure over the next decade in various parts of the country, the CECA Forum believes that such transitions must not threaten the long standing electric reliability and economic benefits of the electric power system to which consumers are entitled.

## The CECA Forum's Consensus Process

The CECA Transmission Infrastructure Forum convened its blue-ribbon panel of the nation's leaders representing such diverse constituencies as investor owned utilities, rural electric cooperatives, municipal power systems, federal power systems, independent power producers, equipment manufacturers, Congress, FERC, the U.S. Department of Energy ("DOE"), state legislatures, state public utility commissions, state energy offices and consumer advocates, consumer and environmental organizations, independent consultants, and academic institutions.

The CECA Forum conducted its year-long examination of these issues in an off-the-record setting in which the broad spectrum of stakeholder views could be candidly expressed and where partisan and ideological conflicts were minimized. Using analysis, information-sharing, and deliberation, the CECA Forum's objectives were to:

- Facilitate an environment that spawned new ideas, approaches and solutions to the issues;
- Reach consensus where possible, and an understanding of alternative perspectives when consensus was not possible; and
- Create a report with a broad set of findings and policy recommendations that is widely circulated to stakeholders and to policymakers at all levels of government.

To accomplish those objectives, the CECA Forum organized its work into three broad parallel

efforts through the establishment of Working Groups. Each of the Working Groups developed draft findings and public policy recommendations which were considered in Plenary Sessions of the CECA Forum. The Working Groups were the following:

**System Planning and Operations Working Group:** The System Planning and Operations Working Group created an inventory of current practices for regional transmission planning and grid operations, and then evaluated those practices against a set of consumer priorities developed in Plenary Sessions of the CECA Forum. The Working Group's analysis considered issues such as coordination of regional transmission planning, effects of multi-state regulation, consumer input into the transmission planning process, cost allocation and cost recovery issues, and operations issues. The System Planning and Operations Working Group was co-chaired by Charles D. Gray, Executive Director of the National Association of Regulatory Utility Commissioners ("NARUC"), and Roberta S. Brown, Vice President of Transmission, PEPCO Holdings, Inc.

**System of the Future Working Group:** The System of the Future Working Group examined the current trends in U.S. transmission system investment and considered whether the system meets forecasted consumer needs for the future. The analysis was conducted through a scenarios process in which a "business as usual" case was developed and then compared against an alternative case, with different assumptions about consumer demand, deployment of advanced transmission technologies and other key variables. The scenarios approach was based on a series of assumptions about factors affecting the transmission system and the analysis addressed the impacts on the system and the consequent implications for consumers. The System of the Future Working Group was co-chaired by Commissioner Laura Chappelle of the Michigan Public Service Commission and Garry Brown, Vice President of Strategic Planning for the New York Independent System Operator.

**Options Working Group:** The Options Working Group, in tandem with the other two Working Groups, undertook a review of the current barriers and potential solutions to encouraging investment in the transmission system. In doing so, the Options Working Group analyzed the institutional, structural/functional and pricing/cost recovery barriers to investment in the system. The Options Working Group was co-chaired by Commissioner Constance White of the Utah Public Service Commission and John Anderson, Executive Director of the Electricity Consumers Resource Council ("ELCON").

## Structure of the Report

This report is organized into three parts:

***Part One*** sets the stage for why CECA undertook this intensive examination of transmission issues. Chapter One outlines the purposes and the goals of the CECA Forum, the process utilized in the CECA Forum, and summarizes the recommendations put forward. Chapter Two further frames the issues by defining a set of national consumer priorities that formed the basis of the deliberations of the CECA Forum. Chapter Two also describes the historical background of the U.S. bulk power system and discusses economic and policy changes that have affected the grid.

***Part Two*** analyzes the current state of the U.S. transmission system and the implications for consumers if changes are or are not made to upgrade and modernize the grid. Chapter Three addresses both the underlying assumptions and whether the continuation of current transmission investment trends will lead to a grid infrastructure that will be adequate to ensure a reliable and economic transmission system. In particular, Chapter Three looks at the reliability, economic, environmental and national security impacts on consumers if adequate investment fails to take place. Chapter Four examines current transmission planning and operations practices and procedures on a regional basis and looks at how coordination of transmission planning, cost issues and regulatory structure affect consumers. Chapter Five

examines the impacts on consumers of changes to the grid, including the deployment of advanced technologies.

***Part Three*** offers the CECA Forum's public policy recommendations. Chapter Six lays out recommendations intended to assist policymakers in the task of how best to move forward to ensure that the electric power transmission system meets consumers' needs for high quality, affordable, and reliable power.

## CECA Recommendations

The CECA Forum expended great effort investigating and deliberating on transmission issues that affect consumers. The results of the CECA Forum's efforts indicate that action must be taken now to ensure that the transmission system will be robust enough to respond flexibly to changes and continue to provide consumers with the reliable, secure, and reasonably priced electricity services necessary to support their social and economic well-being.

Guided by the consumer priorities established by consensus of members of the CECA Forum, the Forum analyzed current trends in transmission investment, as well as planning and operations policies and practices. This analysis included an assessment of the current transmission system and its ability to respond to changes and to continue to provide consumers with the level of electric service they have come to expect.

Through its analysis and deliberations, the CECA Forum developed a series of recommendations directed to policymakers, regulators, and transmission owners and operators that identify and address the barriers to transmission enhancements that could benefit consumers. These recommendations call for the need for immediate or near term action in some instances and articulate principles to guide future policy development in others. Together they constitute an action plan that CECA believes will result in cost-effective operation and maintenance of, and enhancements to, the transmission system to meet increasing end-use consumers' demands on the system. The recommendations also address steps to ensure that the physical transmission infrastructure is maintained – with attention to critical infrastructure and security needs – in a way that will assure reliability and support economic transactions, whether in a traditionally regulated or a competitive market framework.

The CECA Forum recommendations described in detail in Chapter Six address seven areas that are key to the development of a robust transmission system that can respond flexibly to current and future consumer needs in a cost-effective manner, and that will produce benefits for consumers over the long term.[14] These seven key areas are summarized below:

- ☑ **Consumer Input** to transmission policy development is critical to ensure that consumer needs are taken into account in transmission planning and operations. Consumer representatives bring an important perspective to the transmission debate, and planning processes should provide the opportunity and means for consumers to weigh in effectively on important transmission issues such as the need, location and cost of new facilities that will affect their well-being.

- ☑ Consumers want **Reliable Electricity** at stable and affordable prices. Transmission owners and operators must be held accountable for compliance with established reliability standards and best transmission planning and operations practices. These standards should be clear and enforceable. The authorities responsible for enforcement should also have clear rules under which to operate.

- ☑ A clear, consistent and durable **Regulatory Framework** is needed to provide transmission owners and investors with the guidance they need to make investment decisions that will benefit consumers. This regulatory framework must resolve uncertainties with respect to jurisdiction and

electricity policy direction in order to remove existing barriers to investment that are threatening reliability and increasing costs for consumers in some regions of the country.

- ☑ **Institutional and Structural Options,** such as Independent System Operators ("ISOs") or Regional Transmission Organizations ("RTOs"), should be explored and, where such institutions are appropriate, they should be implemented to improve planning and operations and reduce long-term costs to consumers. Transmission planning processes should be developed that clarify responsibility for investment and planning and mechanisms to ensure compliance with sound operations practices should be implemented. The institutional, structural and organizational form(s) that utilities and other entities responsible for transmission should adopt will appropriately vary by region given their different histories, industry structures, and regulatory policy preferences.

- ☑ **Cost Recovery and Allocation** mechanisms for transmission-owning utilities and other transmission providers must be developed to remove disincentives for investment in transmission to ensure that timely and cost-effective investments in both reliability and economic upgrades will be made – and made efficiently. These regulatory mechanisms should recognize that market-based incentives for transmission investment may be insufficient to result in transmission construction in the time frame that it is needed. The question of which sets of consumers benefit from transmission investments and consequently who should pay for them must be resolved in a way that ensures consumers are fairly and equitably treated now and over time. Policymakers and regulators should recognize that existing cost recovery and allocation mechanisms influence the behavior of transmission owners and operators. Consideration of the benefits and costs of moving toward performance-based regulation, with explicit rewards and penalties for transmission owners and operators, must take into account the effects on consumers and ensure that they benefit from any such change.

- ☑ **Regional Transmission Planning** is needed to ensure the development of a robust transmission system capable of responding flexibly to changes (e.g., in fuel prices and availability) to meet consumer needs reliably and at reasonable cost over time. Transmission planning processes must be comprehensive, taking into account the interconnected nature of the grid and factors affecting transmission system utilization such as generation additions and retirements, new types and locations of generation resources (including distributed generation), energy efficiency and demand response, fuel prices and availability and delivery systems, and environmental impacts. Transmission planning should include interregional coordination, particularly with respect to key technical factors such as voltage levels and system protection mechanisms. Regional transmission planning must address inter-regional coordination, the need for both reliability and economic upgrades to the system, as well as critical infrastructure to support national security and environmental concerns, in addition to system-related needs.

- ☑ Finally, policymakers, regulators, transmission owners and the electric industry must look to the future and provide **Public/Private Funding for Advanced Technologies** that can enhance transmission system performance in the near term and provide value-added services and benefits for consumers in the long term.

## Notes

1 Hereinafter, "the August 2003 Blackout."

2 U.S.-Canada Power System Outage Task Force, *Final Report of the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* April 2004, p. 1. Hereinafter, "U.S.-Canada Blackout Report, 2004."

3 Electric Power Research Institute ("EPRI"), *Electricity System Improvements Needed to Prevent Losses,* July 31, 2001.

4 See ISO-NE, *Regional Transmission Expansion Plan 2003,* Table 3.8, p. 42. PJM identified $499 million in congestion costs in 1999 alone for the 25 million people in the PJM market area (all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia). See PJM, *State of the Market 2003,* March 4, 2004, pp. 15, 157. However, this congestion was offset by lower purchased power costs as a result of the increase in size of PJM's footprint and the availability of lower cost generation. Thus, any review of congestion in the PJM system needs to consider the lower purchased power costs that customers realize from being able to purchase from additional lower cost resources.

5 For example, Alcoa recently announced plans to relocate smelters from Texas and Oregon to Canada and Iceland, where electricity is less expensive (Bloomberg News, 5 April 2003 - See http://www.pittsburghlive.com/x/kqvradio/print_127616.html).

6 North American Reliability Council ("NERC"), *2004 Long Term Reliability Assessment,* September 2004, p. 12. Hereinafter, *"NERC, Long Term Reliability Assessment 2004."*

7 "Over the next 10 years, normalized transmission capacity is expected to vary from +2percent (NPCC [Northeast Power Coordinating Council]) to -18 percent (FRCC [Florida Regional Coordinating Council]) across the [NERC] regions. All but one region (NPCC) projects declines in normalized capacity, with the largest drops (more than 15 percent) expected in MAAC [Mid Atlantic Area Coordinating Council], MAPP [Mid-Continent Area Power Pool], and FRCC." Eric Hirst, *U.S. Transmission Capacity: Present Status and Future Prospects,* June 2004, p. 11. Hereinafter "Hirst, June 2004."

8 U. S. Department of Energy ("DOE"), *National Transmission Grid Study,* May 2002, p. 33. Hereinafter, *"DOE, National Transmission Grid Study, 2002."*

9 One such example is Path 15 in California, where CAISO (California Independent System Operator) estimated that congestion from September 1999 to December 2000 cost electricity customers $222 million (Swidler Berlin Shereff Friedman, LLP, "Re: California Independent System Operator Corporation/Amendment No. 63 to the ISO Tariff," September 7, 2004. Hereinafter, Swidler et al., 2004.)

10 DOE Secretary's Electricity Advisory Board, *Transmission Grid Solutions Report,* September 2002, p. 15. Hereinafter, *"DOE, Transmission Grid Solutions Report, 2002."*

11 One cost recovery approach is known as "beneficiaries pay." This approach is sometimes also referred to as "participant funding" when entities that directly benefit from an upgrade agree to pay its costs up front.

12 This report discusses various aspects of funding transmission investment and the implications of different methods in terms of the support they provide for investment and their impacts on consumers, but does not choose any one method in recognition of the different approaches that are being taken in different regions.

13 Consumer Energy Council of America, *Positioning the Consumer for the Future: A Roadmap to an Optimal Electric Power System,* April 2003.

14 This brief overview of these recommendations is intended to provide the reader with some context and guidance for reviewing the discussions of current trends in transmission investment and their implications for consumers (in Chapter Three), transmission planning and operations practices and what they mean for consumers (in Chapter Four), and the potential implications of inevitable changes in demands on the transmission system (in Chapter Five).

Chapter 2

# Why a Robust Transmission System Is Important for Consumers

Reliable and reasonably priced electricity is a necessity of modern life, and a robust transmission system is critical to providing it for consumers. The August 2003 Blackout illustrated the consequences for consumers when the transmission system shuts down. Widespread outages are extremely unusual, however. More typical for consumers are the many ways in which the electric transmission system can prove insufficient on a smaller scale, due to prolonged periods of transmission system congestion that can increase electricity costs, or transmission system constraints that necessitate operation of specific power plants, thus possibly raising power costs and exposing consumers to the price risks associated with the exercise of market power. Even when action is taken to address the need for reliability and economic upgrades, delays in putting needed solutions in place, due to such factors as siting, permitting, and construction, can also impose costs on consumers in terms of reliability risks, higher prices and environmental impacts.

*What distinguishes the CECA Forum and this report from many other studies of transmission issues is the focus on the interests of and impacts on consumers and on what consumers need from the transmission system.*

## Consumer Priorities

What distinguishes the CECA Forum and this report from many other studies of transmission issues is the focus on the interests of and impacts on consumers and on what consumers need from the transmission system. Reliable and reasonably priced electricity can:

- help ensure that consumers receive the power they need for their homes, businesses and factories in a safe and affordable manner;
- assist in reducing the environmental impacts of electricity production and use;
- ensure economic development;
- support national security; and
- help support the power quality and reliability needed to support an increasingly digital economy.

To evaluate the need for transmission enhancements from a consumer perspective, the CECA Forum identified a series of "consumer priorities" to guide the analysis of issues relating to transmission investment, planning and operations policies and practices. A robust transmission system (i.e., one that is most importantly, reliable, but also strong and flexible enough to respond to changing demands) is vitally important for consumers and the CECA Forum's "consumer priorities" serve to make the consumer interests transparent. These priorities were used by CECA Forum members as criteria against which the performance of the transmission system was measured and as a framework for developing CECA's public policy recommendations. The priorities described below are the following:

- Reliability/Adequacy/Security;
- Cost of Power;
- Safety;
- Timeliness, and
- Transparent Planning Processes.

### *Reliability/Adequacy/Security*

The reliability, adequacy and security of electric power service are essential elements in meeting consumer needs. Since the August 2003 Blackout, consumers have experienced a heightened awareness of the vulnerability of the electric power delivery system to widespread failure due to faulty operations. The tragic events of September 11, 2001, also raised awareness of the vulnerabilities of the system to potential terrorist attacks. Both of these events have demonstrated how the reliability of the transmission system can be affected by both internal and external factors. With the proliferation of new electricity-dependent technologies such as computers and increased requirements for high quality power by manufacturers, consumers have placed a higher priority on reliable electricity in their daily lives. Consumers require a transmission system and electricity supplies that are adequate to meet their changing demands. One of the most important aspects of adequate transmission investment is the ability to deliver affordable power under a number of different scenarios, including different fuel price and availability conditions. On a broader scale, the national economy depends on plentiful, reliable and affordable electricity. Electric industry restructuring,[1] with the addition of new institutions such as ISOs/RTOs, and new types of demands placed on the transmissions system (e.g., multiple, complex interregional transactions), have brought attention to the complex challenges faced by the transmission grid in providing reliable, adequate and secure service to consumers. Where the system is not meeting consumers' needs in these areas, enhancements to the system must be made.

### *Cost of Delivering Power: Assuring Adequate Transmission Investment and Equitable and Fair Recovery of Transmission Costs*

At the same time that consumers require reliable, adequate and secure electricity service, they also should be provided electricity at stable and affordable prices. While affordable power is a priority to consumers, consumers are generally not aware of whether such low-cost power is produced locally or delivered from distant locations via power lines. The environmental impacts of electricity production, delivery and use, and the impacts of electric facilities on the aesthetics of their surroundings and on their property are also consumer concerns. While some consumers may be willing to pay more for electricity from "green" resources which positively impact the environment, most consumers do not draw direct connections between the environment and their electricity use. Because consumers do not make these connections between local environmental conditions, the presence or absence of local power facilities, and the price of electricity as reflected in their electricity bills, it is generally understood that consumers influence infrastructure investments by virtue of their pressure to keep electric rates affordable. Therefore, from a consumer point of view, investments in transmission enhancements must be viewed in terms of weighing overall benefits versus overall costs to consumers.

There are several dimensions to the cost of power for consumers. One aspect is assuring that cost recovery and the pricing structure for transmission provide correct signals to investors to make timely cost-effective transmission investments when needed, and when the benefits of such investments can be clearly proven. Where such investment is warranted, timely investment recovery and pricing policy is in consumers' interests. Consumers will be affected if transmission prices and the revenues they generate fail to attract adequate investment for reliability and economic upgrades. Moreover, poorly considered transmission pricing may result in higher costs for consumers.

One of the most important aspects of transmission costs is the question of who pays. While transmission investment in response to demonstrated reliability and economic needs can lower the cost of delivered power to consumers in general over the long term, it may raise costs for certain groups of consumers in the short term. This can occur due to the timing of the investment, the costs and benefits of such investment, as well as the fact that there is not perfect alignment between those who benefit from an investment and those who end up paying for its costs. In utility regulation, there are many bases on which investment costs and benefits may be allocated to different groups of consumers. A long-held regulatory and economic principle is that those who benefit from or cause costs should bear them. With transmission, though, the application of this principle is complicated. The beneficiaries of a transmission investment today may not be the beneficiaries in the future, or more likely, they will be joined by other beneficiaries as time goes by. Similarly, some transmission enhancements may provide specific benefits to some consumers, and indirect benefits, in the form of enhanced system reliability, to all consumers.

Given that the costs of transmission typically end up being charged to consumers through utility rates that cannot be avoided or bypassed (e.g., by disconnecting from the grid), it is particularly important that these distributional impacts – i.e., the fact that individual or groups of transmission consumers may not share equally in the benefits and costs of transmission enhancements over time – be recognized and addressed so that regulatory policies create appropriate investment incentives. Consumers should only pay for transmission investment where the benefits they receive from investment have been demonstrated to exceed the costs. However, the process of identifying the precise beneficiaries should not become a barrier to timely and cost-effective investment.

### *Safety*

The safety of the electricity system is of paramount importance to consumers. Consumers want to be assured that nearby high voltage transmission facilities are located, designed, operated, and maintained in a manner to ensure public safety. Their concerns and interests in the safe operation of the electric grid range from any potential effects of electromagnetic fields to safe operations and maintenance practices. Transmission owners must follow relevant codes and standards during the siting and construction process. These safety standards are fairly consistent across regions. Transmission owners and investors must understand and respond to consumers' safety concerns, particularly when they are seeking to construct new or enhance existing transmission lines.

### *Timeliness*

Timely action to address transmission needs is implicitly important to consumers. For example, the failure to act in a timely manner by parties responsible for upgrading existing transmission lines or building new ones or for approving proposals for such facilities can add costs that are likely to be passed on to the consumer.

The need for timely action to facilitate transmission enhancements must take into consideration the importance for all participants in the regulatory process to have a reasonable opportunity to be heard. Some argue that interveners can cause unnecessary delays by abusing the regulatory and legal process, adding costs to transmission upgrades that will eventually be borne by consumers. Others contend that participation by all interested parties in these processes is critical to ensuring that the benefits of transmission investments exceed the costs and that abuse of the legal process is rare. The CECA Forum's view is that consumers will ultimately benefit if they or their representatives have meaningful input into the process. More importantly, transmission facilities are most likely to be funded and built in a timely fashion where there is regulatory certainty with respect to cost recovery, e.g., clear cost allocation and recovery rules that provide assurance that investors will have a fair opportunity to recover

their prudently incurred costs[2] and efficient regulatory processes for determining these costs and their allocation.[3] These regulatory processes must also provide assurance that overall consumers will receive benefits commensurate with any costs they are asked to pay. Regulatory certainty will require streamlining and/or efficient and timely coordination of approvals among the local, state and federal authorities. Provisions to guard against abuse of the process should be adopted.

### *Processes for Transmission Planning and Determining Need for New Transmission*

Consumers are entitled to a process that plans for and determines the need for transmission system upgrades that is transparent, conducted by individuals with high-level expertise, and ensures the delivery of reliable, safe and affordable power.

The process for determining the need for new transmission should always include an analysis of benefits and costs to consumers to determine the economic advantages of various additions and/or upgrades compared with the costs to achieve them. Consumer input is critical to this process. Consumers must have the information and analytic capabilities to participate effectively in regulatory review, as well as planning processes.

To benefit consumers, regional transmission planning must also be done in a transparent manner, assisted by experts who take not only technical considerations into account but also consumer preferences and needs into consideration. Consumers should be able to participate in and influence the processes that determine the principles and priorities for transmission planning and investment. They should also have the ability to see that transmission operations are being conducted in compliance with established reliability standards. There are opportunities for consumer input through federal, state and local regulatory processes, though these opportunities vary substantially among states and regions. They should be accompanied by the opportunity to represent the consumer perspective in the earliest stages of transmission planning as well. Again, consumers' ability to affect transmission planning processes depends on their being adequately informed and having sufficient analytic tools to provide meaningful input into the process.

## History of the U.S. Bulk Power System

Most consumers tend not to be aware of the critical role played by transmission in assuring reliable and reasonably priced electricity. Yet, for most of the past century, transmission systems have been an essential component of such electric service. Transmission *lines* in the U.S. were originally built to interconnect electric generating stations with the local wires that distributed power to consumers so that power from distant power plants could serve the customers.

Transmission *systems* took on significance when Samuel Insull, the founder of the modern electric utility and head of Commonwealth Edison Company in Chicago, undertook an experiment in 1911 to link several small power systems in Lake County, Illinois with a high voltage transmission network.[4] Insull found that by building and operating transmission facilities to link small systems, thus making a more diverse set of power plants available to a larger set of consumer loads, the savings in power production costs (e.g., fuel, operations and maintenance) more than paid for the capital investment in transmission.[5]

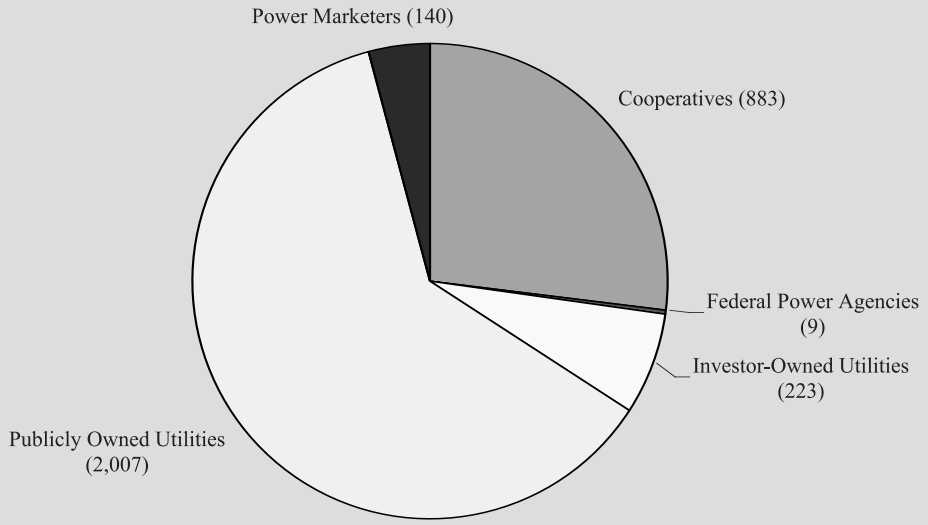
Transmission also made other savings possible: larger and more efficient power plants could be built to supply power to a larger aggregation of consumers; and their patterns of usage – steadier demand for electricity over the hours of a day, days of a week, weeks of a year (i.e., higher load factors) – reduced the amount of reserve generating capacity needed because the demands of individual consumers complemented others. That is, "[t]he diversity between the times at which peak loads occurred on different systems…allowed the same generating equipment, and sometimes the same transmission equip-

ment, to supply more than one load."[6] This reduced overall costs to produce power to consumers. Profits increased to the utility owners and prices for consumers decreased. Transmission provided reliability benefits in the form of access for consumers to more interconnected generators so that the impact of the loss of any one of the generators was reduced. It also provided the benefits of economy transactions by connecting consumers to more remote, but lower cost, power plants. The networking and aggregation of small systems and the resulting reductions in costs continued through the first decades of the 20th Century.

The variety of electricity providers and transmission owners is illustrated in Figure 1.

Along with cost savings, advances in transmission technology shaped and drove changes in the system.[7] The first transmission lines were direct current ("DC") but these were soon overtaken by the use of alternating current ("AC") because of its ability to change voltage to match consumer end-use needs. AC technology continues to dominate the U.S. electricity grid today (although DC interconnections between AC systems are receiving increasing attention as a means of controlling power flows and potentially isolating systems). As transmission systems grew, the emphasis turned to developing higher voltage transmission that could efficiently carry the increasing loads placed on it. Higher transmission voltages required additional measures to separate lines on poles and to provide clearances from the ground. Technology advances in conductors supported this development. With growth in the electricity grid, transmission and distribution lines proliferated and the installation of overhead lines became problematic in certain locations. The development of technologies to permit the "undergrounding" of transmission enabled transmission installation in these areas. The increasing complexity of the transmission system and growth in bulk transfers of power required additional technical support that was provided through the commitment of utility companies and utility equipment providers to ongoing research and development.

**Figure 1**
**Number of Electricity Providers, By Type of Ownership**




Source: Form EIA-861, Preliminary 2003

From its inception until the mid 1960s, the electric utility business was what economists call a "declining cost" industry – the cost of each new increment of capacity was less than the average cost of the system so that its addition to the system reduced overall costs. Because of the opportunities presented by the declining cost nature of the industry, the economies of scale of aggregation, the advantages of integrating transmission and generation through coordinated planning and operation (i.e., attributes that led to the characterization of the electric industry as a "natural monopoly"[8]), utilities grew and complex holding company structures were created. Pricing abuses from some holding companies and the financial collapse of others during the Depression led to increased state and local regulatory oversight as well as the passage of the Federal Power Act[9] and the Public Utility Holding Company Act[10] in the 1930s to regulate price and industry structure.

Under the emerging regulatory framework, utility rates were based on costs to serve consumers, with an allowed return on investment. The rate of return was determined by regulators to be sufficient to attract investment given the lower risk associated with the exclusive service franchise of a regulated monopoly with an exclusive service franchise, i.e., the right to be the only utility entitled to serve consumers in a defined geographic area. This regulatory scheme came to be known as Rate-Base Rate-of-Return Cost-of-Service regulation.

This industrial model worked well for utilities, regulators and consumers as long as electric utilities were a declining cost industry. Utilities made investments in increasingly large power plants and transmission facilities to meet growing consumer demands; utilities continued to earn stable profits even when increasing sales relative to costs meant that rate reductions occurred as a result of periodic rate cases; and consumers experienced the benefits of the declining cost features of the industry.

Over time, things began to change. The Great Northeast Blackout of 1965 revealed weaknesses in the design of the interconnected transmission system. As a result of the 1965 Blackout, the North American Electric Reliability Council ('NERC") was established as a voluntary organization of electric utilities to improve, coordinate and set standards for the planning and operation of regional power grids.

Also, by the mid 1960s through late 1970s, the underlying economics of the electric power business were changing, at least for some parts of the industry. With respect to generation, utility system costs were no longer declining due, in part, to a number of trends: the greater amount of capital required for larger coal and nuclear power plants; the capital investment required for additional transmission to interconnect these larger central station generators to distant loads; the large generating capacity additions, which led to large surpluses for a number of years until demand growth met up with those capacity additions; and the slowing of demand growth due to higher rate increases, in part from the recovery of these large capital additions as well as fuel price increases following the 1973 OPEC oil embargo and the 1978/79 Iranian Revolution; and, as the decades progressed, increasing environmental and power plant safety regulations (in the period following the Three Mile Island nuclear accident) that imposed costs on the utility industry.

Rate cases in some states no longer led to reductions in electricity prices to consumers; in fact, it was just the opposite. Rate cases became increasingly contentious with consumer advocates arguing that utility costs should not be passed on to customers because of the utility's imprudent management. State public utility commissions disallowed the costs of many large power plant additions – notably nuclear investments – in many states. Over time, there was a wide diversity of rates among high and low cost states. In this context, high electricity rates and the effects of oil and other perceived fossil fuel shortages drove Congress to pass the Public Utility Regulatory Policies Act of 1978 ("PURPA")[11] and the Power Plant and Industrial Fuel Use Act.[12] Among other things, PURPA was intended to counter rising utility costs and reduce U.S. reliance on expensive and, it was believed at the

time, increasingly scarce fossil fuels (oil and natural gas). PURPA encouraged cogeneration, due to its efficiency of fuel use, and renewable sources of electricity. Pursuant to PURPA, electric utilities were required to purchase the output of qualifying cogenerators and small renewable power producers, known as Qualifying Facilities ("QFs"), at prices that were based on the utility's "avoided costs," or the costs that the utility would otherwise have had to incur to serve consumers. In the alternative, utilities were required to transmit such power to alternative purchasers; very few utilities chose to transmit the electricity.

PURPA, and the regulations implementing the statute by FERC and state public utility commissions, led to the growth of non-utility generation suppliers (i.e., power plants developed by non-utilities), eventually including not only QFs but also "independent power producers" (now commonly known as "competitive power producers"). QFs proliferated, especially in states that established relatively high avoided cost rates (i.e., where the prices paid for QF power were high enough to attract investment, in many cases because of the high "avoided costs" which the utility would otherwise pay for its own generation) and that required utilities to enter into long-term contracts for QF power.

At the same time, advances in power combustion technology from military research and development ("R&D") were made available to the power industry, leading to the advent of gas-fired combined cycle power plants. These new power plants were modular units and smaller in size, used more efficient technology, had relatively low environmental impacts, fewer siting challenges, and capital costs significantly less than recent utility additions to capacity (which were primarily large, central station base load plants, including nuclear plants). They were also built at a time when natural gas prices were low and expected to remain so. Given these characteristics, combined cycle power plants could be located relatively close to loads, offered the opportunity for relatively efficient dispatch at intermediate load conditions, and could be financed through innovative non-utility investment and debt arrangements that depended upon long term contracts with utility buyers of power. In some states, utilities that might otherwise not have sought to add new generation because of then-existing surplus power conditions were required by regulators to sign long term power contracts with QFs and, in time, with independent power producers. Some of the states with highest costs began to require their utilities to undertake "least cost planning" processes, to assure that the incremental resource additions – whether utility plant, or non-utility-owned power, or even demand-side measures – provided power to consumers at lowest cost.

These conditions created substantial economic, policy and political pressure on the then-existing structure of the industry, in which traditional vertically-integrated utility companies owned generation, transmission and distribution facilities to serve consumers. First, these conditions undermined the then universal premise that electric power generation was a natural monopoly and that the only way to build power plants efficiently and at low cost for consumers was to have utilities build them as part of a vertically-integrated organizational structure. States with high power costs turned to market forces as a way to control the costs of power plants, with the expectation that competitive pressures and innovative models for power plant development, financing, construction, and operations would spur more efficient power production over the long run as compared to the traditional cost-plus utility framework. These changes laid the foundation for policy changes that led to the current and still evolving industry structure.

The development of QFs and competitive power producers also had implications for the operation and use of the transmission system as well as for transmission policy. While these policy and technological innovations led to the opportunity for competition in the generation of electricity, in order for these non-utility power plants to be competitive they nonetheless depended upon access to and use of still-monopoly transmission facilities owned, controlled and operated by utility companies.

Competitive power producers had to be able to interconnect with and use the transmission grid in order to deliver power to their customers. This was the case whether the independent power plant was selling its output to the utility in whose service territory it was located, or it was selling its output to consumers of another, more distant utility system. Such competitive power producers tended to locate their facilities relatively close to fuel delivery systems and transmission lines, but not necessarily close to the loads they ultimately sought to serve. They sought to serve those utilities which had relatively high costs, whether close to or distant from the plant. Either way, the competitive power producers had to use transmission facilities owned by others in order to get access to their customers – and consumers. These complex wholesale power market conditions created pressure for regulators to address the terms and conditions of access to and use of transmission facilities that had been built and regulated for other purposes in the past.

## Structural, Economic, Institutional and Policy Changes Affecting the Transmission System

Increasing pressure to add non-utility power plants reinforced the recognition that generation was not a natural monopoly, but that transmission was likely to continue to remain a regulated monopoly for most system applications. In 1992, Congress passed the Energy Policy Act ("EPAct"),[13] making it possible for not just QFs but also competitive power producers to be entitled to access and use of utilities' transmission systems. These requirements in turn put new demands on utilities' transmission planning and operations. Where transmission was once built to interconnect small systems to enhance reliability and to move power from large, central-station power plants owned by the transmission owning utilities to their own load, now increasing amounts of generation output and wholesale power transactions were seeking access to and use of others' transmission systems to deliver power to their own consumers. But significant questions remained to be answered with regard to the terms and conditions of such access. For example, should competitive power producers and wholesale transactions get access to transmission capacity built to serve the needs of a host utility's own customers on the same basis as those customers, or should they be at the margin? Should a utility's own customers have to pay a share of the costs of new facilities that might be required by competitive power producers who might be using the facilities to serve other loads, and where such costs included the incremental costs of both interconnecting to and using the transmission system? How should utilities plan for the transmission service needs of new non-utility generators? Should third-party use of transmission be afforded the same usage rights to transmission as the needs of the native load of the transmission-owning utility?

In 1996, FERC, following on the implementation of EPAct, issued Orders 888 and 889, taking another step toward the development of a competitive wholesale market policy.[14] In Order 888, FERC formally required transmission owners to provide open and non-discriminatory access to the competitive wholesale generation market on terms and conditions similar to those afforded to the use of their transmission systems to serve their own customer requirements. FERC required all transmission providers to provide such transmission through a functional separation of their transmission and generation operations, and further encouraged but did not require transmission providers to establish a new regional organizational structure for the management of regional transmission operations – the ISO – as the means to accomplish this transmission objective. Over the next several years ISOs were formed in California, and different parts of the Northeast (PJM [Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia], New York and New England). California built its ISO largely from scratch, while the Northeast ISOs built on existing power pools where generation was already centrally dispatched and transmission planning and operations were coordinated to a large degree. The planning and development of ISOs in Texas, the Midwest and the Southwest, with

varying degrees of centralized coordination of transmission operations and planning, and control of operations, followed these ISOs.

At the same time, many state regulators and legislatures began to examine retail competition – allowing end-use consumers to choose their electricity suppliers directly – as a way to further extend benefits from competitive wholesale markets to retail consumers and to provide value-added electricity and energy services and products to consumers. The move by state regulators and legislatures toward such retail access or consumer choice generally occurred in the same high-electricity-cost regions of the country as the formation of ISOs, but by no means was universally adopted by every state in those regions.

There were also further refinements to transmission policy. While retail access offered the potential for additional benefits for consumers, it also introduced the possibility of new demands on the transmission system. Competitive power producers interested in serving retail consumers, in addition to an increasing number of generation-only companies selling at wholesale, wanted to use the transmission system to reach their customers. These suppliers sometimes owned or contracted for generation located remotely from their customers. Additionally, many electric utilities and other non-utility wholesale power companies obtained authority from FERC to sell power in wholesale markets at market-based rates rather than traditional cost-of-service rates – i.e., utility rates were based on prices in the market instead of the utility's own cost. These arrangements increased the complexity and the levels of demands on transmission system planning and operations (i.e., with respect to interregional interactions, power flows, and relationships among different but interconnected transmission systems), as well as exacerbated pressures to clarify and modify the terms under which different parties paid for and had the right to use existing and new transmission capacity. In addition, problems with nascent ISO operations and governance began to emerge under the strain of actual market operations, particularly in the area of interregional coordination (i.e., so-called "seams" problems).

In December 1999, FERC issued Order No. 2000,[15] taking ISOs a step further and encouraging transmission owners to turn over the operation of their transmission assets to independent regional transmission organizations, or RTOs, which would operate not only the transmission system but would perform other related services as well. Order 2000 specified four characteristics and eight functions of an RTO. The four characteristics are: independence, sufficient regional scope, operational authority over transmission, and authority to maintain short-term reliability within its footprint. The eight functions are: tariff administration and design, congestion management, managing parallel path flow, serving as a supplier of last resort for ancillary services, operating an Open Access Same-time Information System ("OASIS") to provide public information on total and available transmission capability, market monitoring, transmission planning, and interregional coordination.

In FERC's view, an RTO with these capabilities would be better able to support competitive wholesale electricity markets and respond to emerging concerns about the adequacy of the transmission system. However, this view was not shared by a number of state policymakers and utilities – especially policymakers and utilities located in states with low electricity costs and where traditional vertical integration remained the dominant organizational form in the electric industry – which resisted the transfer of transmission operations from a state-regulated utility company to a regional organization subject to FERC jurisdiction. State policymakers and many utilities in regions with ISOs, relatively high electricity costs, major electric industry restructuring and retail open access, generally began to move toward RTOs while others maintained their traditional organizational structures to serve their consumers. Consequently, different states and regions sometimes moved in different directions, not all of which were in line with FERC's stated objectives for transmission providers and wholesale markets. The continuation of this trend enhanced concerns about seams between regions

and electricity markets, as well as about the adequacy of transmission investment to support transactions both within and between markets and regions.

During the same time period (2000-2001), the California electricity market experienced its failure, the Enron scandals came to light, and some policymakers, regulators, consumers, and market participants lost faith in the ability of competition in the electric industry to deliver benefits to consumers. These events halted any further movement toward retail access (consumer choice) in the states that had not by then adopted it, and led many states and regions to revisit and adjust their plans for progress toward wholesale competition.[16] Part of FERC's response was the July 2002 issuance of its Standard Market Design ("SMD") notice of proposed rulemaking.[17] FERC's SMD proposal would have the RTO administering not only transmission service but also managing centrally organized wholesale energy and ancillary service markets. According to FERC, SMD was designed to standardize markets across the country thereby ending discrimination in transmission access and the practice of different rules in different jurisdictions.

Many states and utilities, particularly those located in the South and West, expressed strong opposition to FERC's vision of a national standardized market. In the West, many were skeptical of what they saw as "more of the same" in the SMD given their experience with California's electric market restructuring and its effects on many other parts of the Western electric regions. In the South, policymakers made it clear that they did not want to cede jurisdiction of what was a more traditionally organized and operated electric system that they believed worked for consumers in terms of providing reliable electricity services at low prices. In the face of this opposition, FERC clarified the SMD vision in a white paper issued in April 2003.[18] In that white paper, FERC indicated that individual regions could follow their own paths to competitive wholesale electricity markets.

Throughout this period, various policymakers, legislators and regulators have called for comprehensive federal energy legislation to address a host of energy issues including those associated with electricity. The 108th Congress failed to pass comprehensive energy legislation and did not consider stand-alone reliability legislation which was supported by many in the wake of the August 2003 Blackout.

Since the expansion of competition in wholesale electricity markets over the last decade, there has been growing concern about the adequacy of the transmission infrastructure to meet new demands placed on it by new uses of the transmission system – expanded bilateral contracts, interconnection of new types of generators with different ownership structures, increased power flows across regions, coordinated operations across interconnected regions, and trading or exchanges of power between parties. These changes have raised a number of questions:

- Who is responsible for planning and building transmission?
- Who provides capital?
- Who determines what upgrades are needed for reliability?
- Who should pay for them?
- Who determines what upgrades are economic and how?
- How can it be assured that additions or rearrangements are best from a long term viewpoint?
- Who invests in and who pays for them?
- How are investment and cost-recovery decisions determined for facilities that have both reliability and economic power benefits?
- How are non-wires options that affect the need for transmission taken into account?
- Who is in charge at the regulatory level? How will uncertainty between federal and state jurisdiction be resolved?
- How should "Not in My Back Yard" ("NIMBY") issues be addressed when they impede (or threaten to impede) siting of new transmission, particularly when it seems to be built to serve the needs of others rather than local consumers?
- How should the implications for the transmission system of various public

policies, such as renewable portfolio standards (RPS) and other policies to promote renewable energy be addressed?

- Finally, how can the reliability of the interconnected transmission system be ensured in a context in which on the one hand, regulatory and public policies and industry organizational models vary by state within and across regions, while on the other hand the transmission network remains largely integrated with systems being affected by actions taken in neighboring and even distantly located systems?

*. . . recent downward trends in transmission investments . . . make it clear that the ability of the transmission system to meet increasing consumer demand will be at risk unless policymakers and transmission system owners and operators act to address the new complexities and challenges facing the system.*

Concerns about the adequacy of the transmission system came to a head with the August 2003 Blackout. Some blamed the restructuring of the electric industry as the cause of the Blackout. Others suggested that restructuring had not yet gone far enough in the region. There were renewed calls for a return to a traditional utility model and regulation. The Final Report of the U.S.-Canada Power System Outage Task Force identified the principal initial causes of the August 2003 Blackout as the traditional ones – inadequate training of personnel, inadequate maintenance (tree trimming) of rights of way, and inadequate monitoring of system conditions.[19] However, the report also recommended that an independent study be commissioned to examine the relationship among industry restructuring, competition and reliability to determine how they might have contributed to the conditions that led to the Blackout.[20]

While traditional operational issues were the primary causes of the August 2003 Blackout, this does not mean that policymakers and those responsible for the reliable operation of the electricity system can be complacent simply to improve traditional operations on the system given new non-traditional uses and demands on it. Rather, recent downward trends in transmission investment, in addition to regional transmission planning and operations policies and practices, make it clear that the ability of the transmission system to meet increasing consumer demand will be at risk unless policymakers and transmission system owners and operators act to address the new complexities and challenges facing the system. Without this action, the reliability of the transmission system and bulk power grid may be threatened and costs to consumers of electricity service are likely to increase.

### Notes

1 Eighteen states have restructured their electric industries to allow for retail choice; the remaining states have either suspended or delayed or have not proceeded to restructure their retail electric industries. See EIA, *Status of State Electric Industry Restructuring Activity as of February 2003,* at http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html. Hereinafter, "EIA, *Status of State Electric Industry Restructuring Activity, 2003.*"

2 A recent study prepared for the Edison Electric Institute ("EEI") and DOE demonstrates that transmission investment in the U.S. has consistently lagged demand growth for over two decades. See Hirst, June 2004, pp. 6-7.

3 In addition, an efficient and streamlined process for siting transmission is also critical in ensuring the timeliness of transmission enhancements, though not the focus of this CECA Forum.

4 Edward Kahn, *Electric Utility Planning and Regulation* (1988), pp. 3-4. Hereinafter, "Kahn, 1988."

5 "On the whole, investment requirements are proportionally (per peak kilowatt) greater for larger system. This relationship will turn out to be an invariant feature of growing systems, since growth is capital intensive. The increased capital expenditures are offset by gains in efficiency and market increases." Kahn, 1988, pp. 5-6.

6 Casazza, John A., *The Development of Electric Power Transmission* (1993). Hereinafter, "Casazza, 1993."

7 See Casazza, 1993, "Chapter 3: The Evolution of Technology and Institutional Arrangements" for a detailed discussion of technology development effects on the transmission system. This paragraph is based on that source.

8 In economics, a natural monopoly is a situation where a single company tends to become the only supplier of a product or service over time because the nature of that product or service makes a single supplier more efficient than multiple, competing ones. For example, it is inefficient to have several electric distribution systems covering the same area. Sometimes the natural monopoly characteristics of an industry change over time, as a result of changes in the fundamental economics of that industry. One such example is the development of wireless telecommunications technologies (e.g., cell phones), which undermined the natural monopoly characteristics of landline telephones companies.

9 *Federal Power Act,* U.S. Code 16 (1920), § 791-828c, (current version 1994).

10 *Public Utility Holding Company Act, U.S. Code* 15 (1935), § 79b

11 *Public Utility Regulatory Policies Act, U.S. Code* 16 (1978), § 2601

12 *Power Plant and Industrial Fuel Use Act, U.S. Code* 42 (1978), § 8301

13 *Energy Policy Act of 1992,* U.S. Code 42 (1992), § 13385.

14 "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," FERC Order No. 888, 18 CFR § 35 and 385 (April 24, 1996); "Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct," FERC Order No. 889, 18 CFR § 37 (April 24, 1996).

15 "Regional Transmission Organizations," FERC Order No. 2000, 18 CFR § 35 (December 20, 1999).

16 EIA, *Status of State Electric Industry Restructuring Activity,* 2003.

17 FERC, Notice of Proposed Rulemaking, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Docket No. RM01-12-000, July 31, 2002.

18 FERC, "Wholesale Power Market Platform White Paper," April 28, 2003 (see http://www.ferc.gov/industries/electric/indus-act/smd/white_paper.pdf).

19 See U.S.-Canada Blackout Report, 2004, pp. 18-19.

20 See U.S.-Canada Blackout Report, 2004.

# PART TWO: ANALYSIS OF THE CURRENT TRANSMISSION SYSTEM

Chapter 3

# The Current Transmission System and Its Implications for Consumers

## Current Trends in Transmission

An overview of the current state of the U.S. transmission system reveals increasing stresses, which vary by region. Transmission congestion in the Northeast is raising costs for consumers in certain locations and may threaten reliability under certain load and system conditions. Transmission capacity in the South in some cases is insufficient to allow lower cost generation in some regions to reach markets for power in other regions where costs are higher. Similarly, transmission capacity from the Middle U.S. to the South and East is insufficient to allow low cost coal generation to reach higher cost markets for power. In Texas and some parts of the West, the configuration of the transmission system affects opportunities for the dispatch of existing, and the location of new, renewable generation resources.

To begin the analysis of ways in which the U.S. transmission system can be improved to meet increasing demands of end-use consumers, the CECA Forum reviewed current trends in transmission investment that have led to the present status of the transmission system. The CECA Forum then considered the effects on consumers of the continuation of these trends over the next decade, looking at both the impacts of the trends on the transmission system and the implications of these trends for consumers. The focus of this Chapter is to address the effects of transmission investment trends on consumers. Transmission planning and operations are briefly referenced with respect to how they affect investment. Transmission planning and operations policies and practices are discussed in detail in Chapter Four.

### *Current Transmission Functions, Organizational Structure and Technology*

The transmission system will continue to serve multiple, simultaneous functions in the electric power system, in addition to its traditional reliability functions. These functions include:

- meeting North American Electric Reliability Council and regional reliability council reliability requirements;
- providing voltage support and other attributes to assure that the electric system functions reliably in real time;
- ensuring that the outputs from a utility's generation can be transported to its own customers;
- reducing the required investment in generation by allowing the industry to capture economies of scale through larger generating plants providing service to a broader geographic area;
- reducing generating capacity reserve margins required to reliably serve consumer load; and
- supporting reliance on remote generation sources located closer to fuel sources (e.g., coal, hydro and renewable energy).

The transmission system makes possible significant reductions in the capital investment required for generation to supply consumers' needs by taking advantage of the diversity of loads between

areas (i.e., consumers' peak demands occur at different times in different regions and therefore are not additive; rather they complement each other) and the differences in availability and price of fuels in various locations, thereby lowering electricity costs for consumers. Transmission also reduces the amount of reserve generation needed to provide protection against unanticipated events (e.g., unexpected outages of generation) by enabling transfers of power between locations or regions.

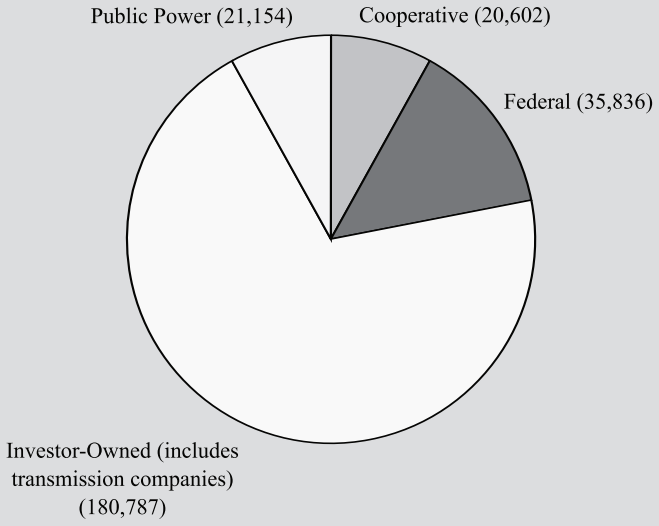
In addition to these traditional functions, the transmission system is increasingly being asked to perform new commercial functions. These new functions have developed in response to and to accommodate new participants in the electric industry, adding to the complexity of utility system planning and operations. These functions include:

- providing competitive power producers with equal access to the grid;
- facilitating the entry of new power producers into the market;
- providing generators and suppliers with access to multiple markets;
- enabling mechanisms for reliably and economically handling of congestion in administrative and market-based ways; and
- reducing problems associated with the potential exercise of local market power held by generation facilities that must run to ensure reliable service to consumers in that area.[1]

Equal and non-discriminatory access to the transmission system is critical for enabling the development of competitive wholesale markets, which is the intent of law as expressed in EPAct and has been the thrust of FERC policy (and the policy of many states) over the last decade. Transmission also plays a role in relieving congestion on the grid, enabling power to flow freely and reliably between generators and load.

Transmission facilities have historically been built predominantly by vertically-integrated investor-owned electric utilities, but are also owned by public power organizations. Figure 2 illustrates structure miles of transmission by form of ownership.

**Figure 2**
**Estimate of Structure Miles of 138 kV or Greater**
**(2002)**




Sources: FERC Form 1, Form EIA-412, RUS Form 7, and Platts "2004 Directory of Electric Power Producers and Distributors"

In recent years, regulated utilities in many states have divested or spun off ownership of some or all their generating assets (e.g., New York, Massachusetts, Maine, Connecticut, Illinois), with the remaining parts of the utility companies continuing to provide transmission, and in some cases, distribution service. Some companies (e.g., in Michigan) have spun off transmission ownership and operations to independent transmission companies ("ITCs"), while some others have established stand-alone transmission companies within a larger organization, and others have continued to own transmission but have ceded operations to ISOs, RTOs and other grid operators (e.g., companies in the PJM system). Many of these changes have taken place over the past five years.

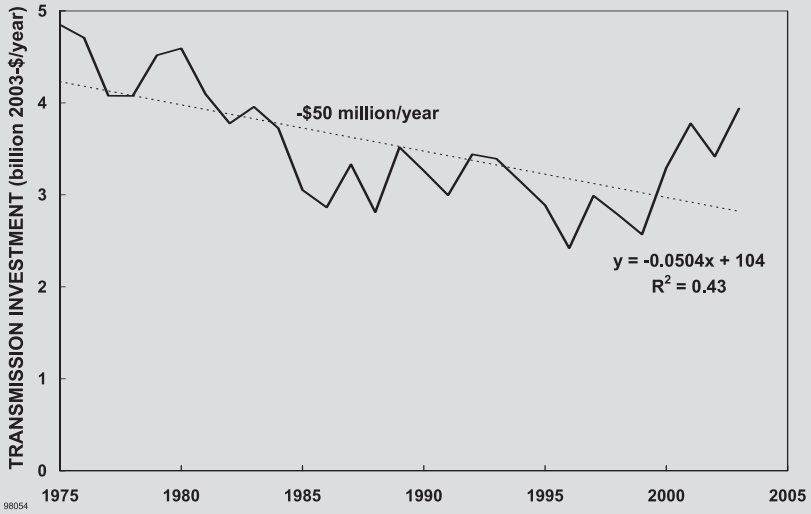
As the CECA Forum considered the future implications for consumers of current trends in transmission investment, no further changes in transmission ownership structure were assumed to take place over the next 10 years except for those that are already underway. Therefore, the two main business models for ownership of transmission in various parts of the nation were assumed to be: (1) separate ownership and control of transmission (where the control functions are handled by a system operator, and transmission assets are owned by other entities – this is basically the system that exists in the Northeast, in California and in Texas); and (2) joint ownership of transmission assets and control of the grid (where the functions of the transmission service provided are combined in a single vertically-integrated entity – such as principally exists for utilities located in the Pacific Northwest and the South). It is assumed that, in the Midwest, the gradual transition from the joint ownership model to the separate ownership and control model will continue.

It is assumed as well that the current transmission system will continue to perform its multiple functions using for the most part the same transmission technologies that have been used over the last 10 years, with the architecture of the transmission system also not expected to change. If available technologies continue to be used, there will be no significant changes in the cost of adding transmission capacity on the margin. That is, transmission investments will still tend to come in relatively large "lumps," based on substantial economies of scope and scale.[2] While a number of new advanced transmission technologies are under development and some are in the early stages of commercialization, unless there are significant factors to cause current trends to be modified in the future, these new advanced technologies will not be deployed to any significant degree during the next decade; nor will funding for research, development, demonstration and deployment ("RDD&D") increase substantially beyond present levels. Instead, incremental changes will be made in capacity additions and technology adoption, introducing some new devices and upgrading existing capacity. The current status of advanced transmission technologies, changes in their possible deployment, and the potential implications for consumers in terms of benefits and costs are discussed in greater detail in Chapter Five.

### *Transmission Investment, Maintenance and Employment Trends*

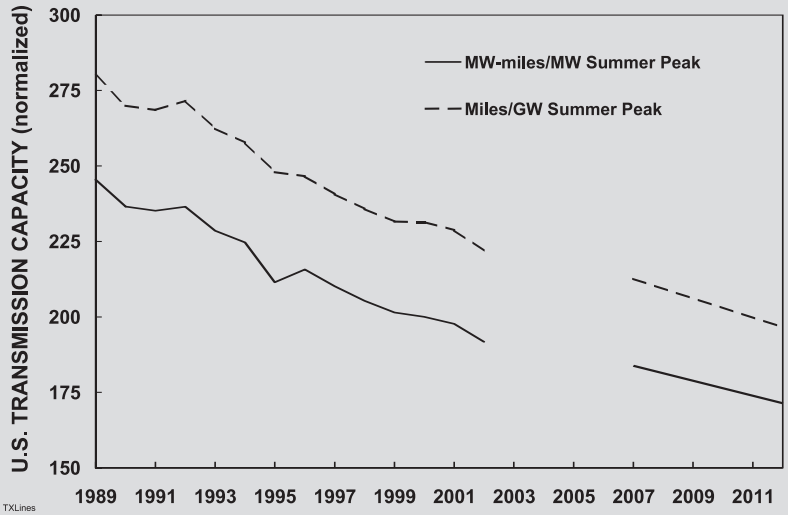
Transmission investment has declined steadily for approximately 25 years, increasing only over the last few. Figure 3 shows that "[b]etween 1975 and 1999, investment fell at an average rate of $83 million per year; from 1999 through 2003, transmission investment increased at an average annual rate of $286 million, a substantial reversal of trends."[3] On a normalized basis – i.e., adjusted for peak demand – transmission investment has declined over this entire time period, although the rate of decline has slowed. Figure 4 illustrates that "normalized transmission capacity declined by almost 19 percent between 1992 and 2002, [but] it is expected to drop by only 11 percent during the following decade (2002 to 2012)."[4] While the decline is projected to level off, with the number of line miles of high voltage transmission added each year expected to grow at one-third the rate of electricity demand over the next decade, investment is expected to remain at a historically low level of about $3 to $4 billion

**Figure 3**
**Historical Transmission Investment**
**(1975 through 2003)**




Source: Eric Hirst, "U.S. Transmission Capacity: Present Status and Future Prospects," Figure 3, August 2004

**Figure 4**
**Normalized Transmission Investment**
**(1989 Through 2002 Plus Projections for 2007 to 2012)**




The gap on the graph is due to the timing of availability of historic data and future forecasts.

Source: Eric Hirst, "U.S. Transmission Capacity: Present Status and Future Prospects," Figure 5, August 2004.

per year.[5] Some view this level of investment as adequate to meet reliability needs, but insufficient to meet economic needs. Opportunities to reduce consumer energy bills are being neglected because of lack of transmission investment.[6]

There are a number of reasons why transmission investment has declined over the last two decades. For example, transmission additions could have declined because

- major construction of large central station generation, such as nuclear plants, was completed, along with associated transmission facilities needed to integrate that generation into the grid;
- regional or interregional transmission had been built to meet long-range needs with the resulting savings;
- adding gas-fired generation closer to loads resulted in reduced need for transmission;
- projections of high rates of load growth were not realized; or
- investment declined as a result of changes in expectations by utility management about the rules governing cost recovery for investment in transmission enhancements.

If the decline in transmission investment is due to slower load growth or changes in the magnitude and location of generation investment, then the decline is likely to have few, if any, impacts on transmission reliability. However, if lower levels of transmission investment are in part the result of uncertainty about cost recovery, the implications for consumers are potentially negative. It is generally believed in the industry that if future transmission investment continues at this historically low level, it will not keep pace with the needs of industry or consumers' demands, and may not be sufficient to maintain reliability and service quality standards for consumers as their demands on the system change and increase in future years.

*Opportunities to reduce consumer energy bills are being neglected because of lack of transmission investment.*

Based on current data, construction of new transmission lines will account for approximately 1000 miles of new transmission per year, consistent with past trends.[7] Table 1 indicates plans for transmission construction from a regional point of view. The majority of transmission investment will be undertaken to meet the reliability needs of the system rather than for economic purposes. Economic purposes include relieving congestion that raises electricity costs for consumers in areas where the transmission grid is constrained when it is cost-effective to do so, i.e., when the benefits exceed the costs of relieving the constraint. Economic purposes also include enhancing wholesale competitive markets.

Because transmission investment is generally not expected to take place for purely economic purposes, transmission congestion could continue to increase in certain geographic areas, depending on a variety of factors related to the location of future generation and the pattern of transactions using existing transmission lines. It should be noted that congestion on the transmission system can change from day to day, and even hour to hour, as conditions, such as weather, change. Building new lines just to relieve congestion is generally economic only when congestion is persistent and where the costs to alleviate the constraints are lower than the benefits of doing so.

Many regions of the U.S. face transmission constraints and bottlenecks which often involve a combination of conditions with both reliability and economic impacts. Transmission congestion typically has localized economic effects and can, depending on an analysis of individual facts and circumstances, result in: reduced choices in supplies and higher costs for end-use consumers and the distribution companies that serve them; requirements to operate power plants out of "economic merit order" and to keep such plants available via expensive "reliability must run" contracts[8] in order to assure reliability locally;

**Table 1**
**Planned Transmission**
**Transmission Circuit Miles – 230 kV and Above**

| | 2003 Existing | 2004–2008 Additions | 2009–2013 Additions | 2013 Total Installed |
|---|---|---|---|---|
| ECAR | 16,439 | 156 | 17 | 16,612 |
| FRCC | 6,894 | 360 | 81 | 7,335 |
| MAAC | 7,057 | 134 | 0 | 7,191 |
| MAIN | 6,195 | 374 | 260 | 6,829 |
| MAPP-U.S. | 14,705 | 228 | 246 | 15,179 |
| MAPP-Canada | 6,660 | 94 | 963 | 7,717 |
| NPCC-U.S. | 6,406 | 376 | 0 | 6,782 |
| NPCC-Canada | 28,961 | 258 | 38 | 29,257 |
| SERC | 28,868 | 1,349 | 1,085 | 31,302 |
| SPP | 7,659 | 191 | 17 | 7,867 |
| **Eastern Interconnection** | 129,844 | 3,520 | 2,707 | 136,071 |
| WECC-U.S. | 58,400 | 1,573 | 1,582 | 61,555 |
| WECC-Canada | 10,969 | 270 | 252 | 11,491 |
| WECC-Mexico | 563 | 24 | 0 | 587 |
| **Western Interconnection** | 69,932 | 1,867 | 1,834 | 73,633 |
| **ERCOT Interconnection** | 8,081 | 290 | 110 | 8,481 |
| U.S. | 160,704 | 5,031 | 3,398 | 169,133 |
| Canada | 46,590 | 622 | 1,253 | 48,465 |
| Mexico | 563 | 24 | 0 | 587 |
| NERC | 207,857 | 5,677 | 4,651 | 218,185 |

Source: NERC, "2004 Long Term Reliability Assessment," Table 3

high price differentials between neighboring regions; restrictions on the entry of new generation; and increased opportunities for the exercise of market power.

Congestion can also lead to grid reliability problems. Figure 5 presents an explanation of the difference between, and the different cost recovery treatment of, transmission investments for reliability and economic purposes.

Transmission maintenance expenditures and employment levels have also declined over the same time period as transmission investment has declined. Expenditures for transmission maintenance have declined at a rate of one percent per year since the passage of the EPAct in 1992, as illustrated in Figure 6. Declining transmission maintenance can affect reliability and the ability of the transmission system to serve consumers. Similarly, employment in various categories of electric utility workers, which is shown in Table 2, is projected to decline over the 2002 to 2012 time period as well. While some of these decreases may relate to improved efficiencies in transmission system operations and maintenance, nonetheless if these trends continue (or even stabilize at current levels), they reduce the personnel available for emergencies or to enable the scheduling of training, leading to a situation where the transmission system may have greater difficulty meeting consumer needs in the future.

### *Planning Impacts on Transmission Investment*

Transmission planning takes place on a varied institutional landscape in different parts of the country. In most regions, transmission utilities undertake their own planning studies and may coordinate with one another through a regional reliability council. In a vertically-integrated utility setting, utility planning usually determines the need for specific facilities – including both transmission and generation – to be built. In regions with ISOs and RTOs, the regional transmission provider also carries out transmission planning and analysis. This type of transmission planning typically involves analyses of generation and transmission facilities proposed by others, and can include proposals from vertically-integrated utilities, transmission utilities, other transmission providers, and generators. The analyses focus on the reliability – and in some cases economic – impacts of particular proposals. All of these efforts are subject to a mixed set of highly-varied sources of pressure and influence: At the federal level, FERC directives require open and non-discriminatory access (Order 888), and FERC policies encourage *regional* transmission organization formation. RTOs are encouraged under both Order 2000 and the proposed Standard Market Design. Within individual states, a variety of state statutes and regulatory policies may exist and govern such factors as transmission facility siting practices; the issuance of certificates of public convenience and necessity as the means to confirm that new transmission facilities are needed; a state's requirement that, in order to be approved for construction, a new facility must benefit the state and not just be proposed to meet the needs of the region or neighboring states' consumers; "portfolio management" requirements imposed on retail electric companies in some states (e.g., integrated resource or other planning requirements on utilities to consider alternatives to the option proposed, such as California's requirement that utilities examine transmission along with generation options for solving particular electric resource needs); cultural norms (e.g., highly collaborative transmission planning processes in the Pacific Northwest); legislative moratoria prohibiting certain types of new transmission facilities; and established but still evolving structures such as Regional State Committees.[9]

With these varied and sometimes conflicting policy directives affecting individual transmission providers, tension among them and between providers and regulators and the uncertainty that results with respect to how transmission planning should occur often create a disincentive to transmission investment. Nonetheless, transmission

**Figure 5**
**Economic v. Reliability Upgrades**

Transmission congestion - operational or physical limits on the ability of a transmission network to move power into or out of an area - leads to power production cost differences between locations. As congestion into one area increases, the costs of energy will similarly increase because lower cost generation from outside that area will not be able to be dispatched and transmitted to serve consumers within the congested area. Consequently, those purchasers will have to rely on local sources of supply, including generation or demand-side management or distributed generation that would not otherwise be relied upon because of having higher costs than the more remote generation. Where costs of these local resources are lower than remote resources, use of the local ones will not adversely affect costs to consumers. However, where these costs are higher, consumers will be disadvantaged. Further, if local resources are not sufficient, consumers in the constrained areas could face reduced reliability which could result in service interruptions in extreme cases.

***Economic transmission upgrades*** bring additional energy from locations with low cost electricity resources to locations with high electricity costs by adding new transmission capacity and expanding congested interfaces. Likewise, economic upgrades can also broaden the market for "locked in" generation that, due to transmission constraints, cannot get out of a low cost region to serve consumers in a higher cost region. (Consumers in low cost areas are sometimes concerned that increasing the transmission system's ability to move power out of that area could increase their costs.)

As congestion on the system increases, power production costs on the constrained side of the transmission interface will increase (assuming no new or only higher cost, generation is, or can be, added on the constrained side of the interface). In addition, the need for operational adjustments to address the congestion (such as dispatch of generation or other resources within the congested area) will increase. While it is possible to operate a system with congestion in a reliable fashion, it may be more difficult because transmission constraints limit the tools the operator has to deal with reliability problems.

If the price signals that result from congestion are not sufficient to cause changes in customer use or generation, then reliability problems can arise. Either consumers, in the form of load shedding, or generators, in the form of cutting or increasing production, will be required to react to protect the system. If this happens with sufficient regularity, then ***reliability transmission upgrades*** will be needed to relieve the congestion to the degree necessary to maintain reliable operations. Reliability upgrades are needed for locations and conditions where reliability standards cannot otherwise be met and are essential for maintenance of system reliability.

Typically, there is not a bright line distinguishing between economic and reliability upgrades. Congestion that initially raises costs can grow to jeopardize reliability. Sometimes, upgrades that at first appear to be economic later become reliability assets. This significantly complicates the designation of a specific upgrade as either economic or reliability. Similarly, any form of congestion that leads to reliability problems will have economic impacts - i.e., it will increase costs.*

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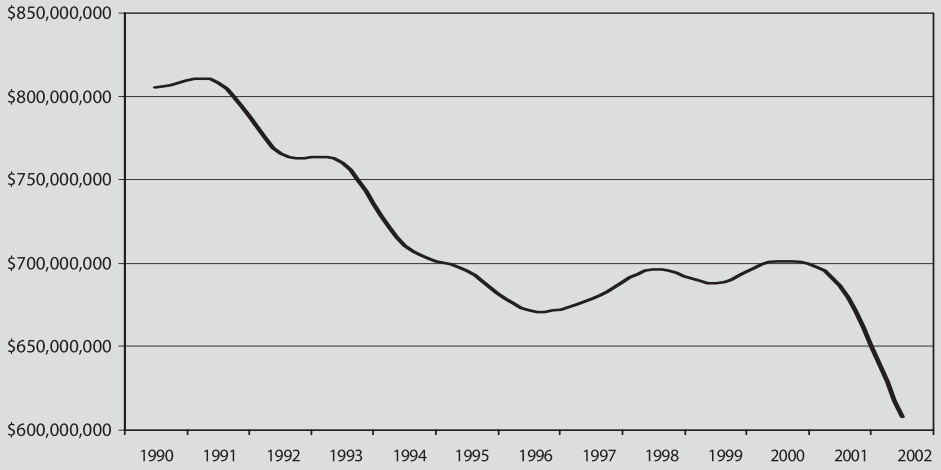
* There is a third category of transmission upgrades, or "enhancements," which has received formal consideration in New England in recent months. These are enhancements that provide entirely local benefits. Examples include burying a transmission facility in order to provide aesthetic advantages relative to an existing (or even planned) transmission line, or re-routing lines to minimize tourism impacts. Additionally, investments in new lines to interconnect generation units fall into neither the "economic" nor "reliability" category yet are necessary facilities to integrate a generator into the grid.

Source: Consumer Energy Council of America

**Figure 6**
**Total Expenditures on Transmission Maintenance**
**(2002 dollars)**




Source: FERC Form 1 aggregate data (RDI/Platts); adjusted for inflation using Bureau of Labor Statistics Consumer Price Index.

**Table 2**
**Industry Employment by Occupation**
**(2002 and Projected 2012)**

| Job Classification | 2002 | 2012 | Job Loss Change | Job Loss Percentage |
|---|---|---|---|---|
| Lineman & Repairers | 52,172 | 49,473 | -2,698 | -5.2% |
| Power Plan Operators | 28,026 | 26,577 | -1,449 | -5.2% |
| Utility Meter Readers | 14,405 | 10,928 | -3,476 | -24.1% |
| Tree Trimmers | 919 | 850 | -68 | -7.4% |
| Nuclear Technicians | 2,637 | 2,250 | -387 | -14.7% |
| Warehousemen | 617 | 516 | -101 | -16.4% |
| Customer Service Reps | 24,645 | 23,371 | -1,275 | -5.2% |
| Office Clerks | 9,068 | 7,489 | -1,579 | -17.4% |

Source: U.S. Department of Labor, Bureau of Labor Statistics, Industry-Occupation Employment Matrix; 2004

planning must continue to accommodate these multiple parties, as well as consider the reliability and economic requirements of the transmission system. These dual requirements include improving reliability to meet industry reliability standards; providing sufficient margins to permit transmission elements to be taken out of service temporarily for maintenance; accommodating load growth and generation development without delay; enabling transfer (i.e., import and export) capability from different directions; reducing service denials and interruptions due to transmission constraints (equivalent to reducing congestion costs); and providing flexibility to transmission customers to modify their transactions as market conditions change.[10]

In the future, transmission planning will also need to explicitly take into account national security requirements to a greater extent than it has in the past. In the wake of the September 11, 2001 terrorist attacks on the World Trade Center, the Pentagon and in Pennsylvania and the August 2003 Blackout, the Department of Homeland Security and DOE are analyzing what measures may need to be taken to enhance grid security and ensure that critical utility infrastructure, including the transmission system, will be able to withstand terrorist attacks. Transmission planning policies and practices are discussed in greater detail in Chapter Four. The implications for consumers of current trends in planning and their effect on transmission investment are discussed later in this Chapter.

*Uncertainty about the terms and conditions under which transmission investment may be recovered . . . is considered one of the major barriers to new transmission investment.*

### *Impacts of Cost Recovery Policy on Transmission Investment*

Uncertainty about the terms and conditions under which transmission investment may be recovered – not only timing and amount of investment recovery, but also the allocation of costs among affected parties – is considered one of the major barriers to new transmission investment. Such uncertainty over investment recovery is particularly a barrier in cases where transmission enhancements are needed for economic purposes. Where transmission investment is tied to improvements that address reliability issues, it is expected that end-use consumers served by the affected utility will benefit broadly from the upgrades and therefore should pay for them. In some instances, ratepayers of other transmission owners may benefit but may not be charged for the upgrades except when the transmission provider undertaking the upgrade is part of a regional organization with cost recovery policies that allow for the investment recovery to be "socialized" more broadly by consumers in the region.

For certain economic upgrades, such as those needed to meet the needs of generators seeking to sell into wholesale markets benefiting consumers in a different region, at times much larger than the area affected by the transmission upgrade, it is sometimes argued that the specific beneficiaries of the upgrade must pay. When specific beneficiaries, such as the generators seeking interconnection, pay up for the costs of an upgrade, this is known as "participant funding." These "participants" receive no payment or credit in return; rather all they receive are what are called "Financial Transmission Rights ("FTRs") associated with the line they funded. (FTRs entitle their holders to the difference in energy prices (i.e., congestion "rents") between two different locations.) When the beneficiaries of an investment are viewed more broadly – for example, as all consumers in a particular location – this funding method is referred to as "beneficiaries pay." Even where there is general agreement regarding "beneficiaries pay," disputes remain about the allocation of costs to local reliability beneficiaries versus distant users who may receive economic benefits from lower generation costs. It is important to note that changes in policies with respect to who pays for transmission investment are being considered

and debated in a number of regions, as is discussed in greater detail in Chapter Four. The reluctance in some regions to invest in transmission, for either reliability or demonstrated cost-effective economic upgrades, potentially threatens reliability and could lead to increased prices for consumers in congested areas. This congestion and its concomitant costs to consumers are likely to increase over time.

## Other Factors

There are a variety of factors influencing demand for transmission and how the transmission system will respond to this demand. The primary influence, of course, is consumer demand for electricity services, which is driven largely by economic growth and the pattern of increased use of existing and new electricity-using technologies. In addition, other influences include fuel price levels and volatility, fuel availability, the location and type of generation additions and retirements and changes in other infrastructure systems, such as fuel delivery systems.

How transmission investors, owners and operators respond to these demands is also affected by public policy and regulatory guidelines and requirements. The CECA Forum reviewed the assumptions underlying current trends influencing transmission demand, and the implications of changes in these factors. Understanding the effect of these underlying factors on the transmission system is important for informing policymakers and consumers about the implications of the policy and other choices they are making. These factors are discussed in detail in Chapter Five.

## Impacts and Implications for Consumers

Assuming the continuation of current trends over the next decade in transmission investment, transmission planning and operations, consumers will be impacted by a variety of benefits and costs. The CECA Forum examined these impacts and implications along four dimensions:

- **Reliability:** Impacts of these trends on system reliability (e.g., frequency of actions to avoid lines being overloaded, increased risk of blackouts);
- **Economics:** Impacts on power system economics (e.g., overall electricity price impacts, price volatility, congestion, exposure to the price effects of the exercise of market power, greater access of purchasers of power to a larger set of suppliers);
- **Environment:** Impacts on environmental issues (e.g., siting impacts, air emissions impacts from power plants given a certain configuration of transmission and generation assumptions); and
- **Security:** Impacts on national security risks (e.g., exposure of the critical infrastructure to terrorist attack).

This section addresses these four areas of impact and their implications for consumers, beginning with a description of how the transmission system can be expected to perform in each area (e.g., from a reliability or economic perspective) given current trends. The discussion then focuses on what this means for end-use consumers during the 10-year time frame addressed by the CECA Forum. CECA notes that there is significant regional variation in the implications for consumers in each of these four impact areas, due to differences in industry organization and regulatory policy, as well as differences in geography and resource availability. The sections below focus on average impacts across the country. Key regional variations are highlighted.[11]

### *Reliability Impacts*

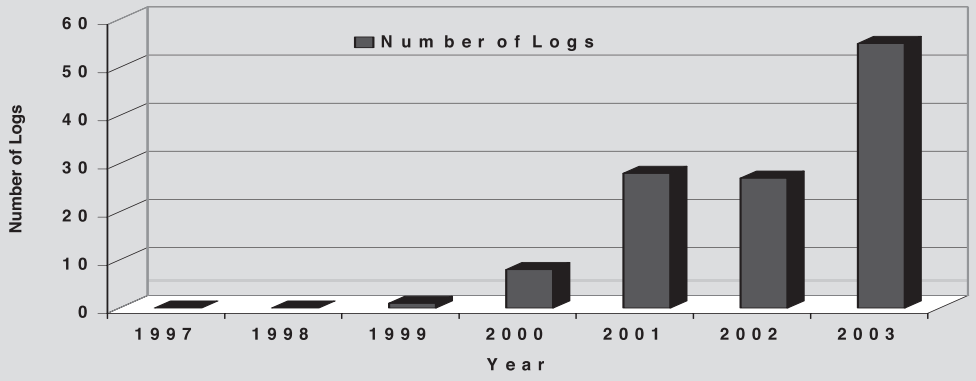
Over the next 10 years, the nation's grid is expected to have the same mixed set of organizations that provide transmission service today. As discussed previously, these entities are assumed to make incremental additions to the transmission system based more on local reliability requirements than on economic reasons alone. Following the trend of the past decade, electricity demand is expected to continue to increase (espe-

cially in Texas and parts of the Southwest and the South), with the grid continuing to be heavily loaded, over more hours of the day and year.[12] In many geographic areas, the number of single or multiple operating contingencies that could create serious problems has increased and is expected to continue to do so into the next decade. Operating the grid at higher loadings will continue to mean greater stress on equipment, a smaller range of options, and a shorter period of time for dealing with unexpected problems.[13]

The bulk power transmission system, which was already stressed (even before the August 2003 Blackout), can be expected to continue to face further stresses and challenges. For example, transmission loading relief measures[14] ("TLRs") – measures implemented by system operators to avoid unacceptable system operating conditions – have increased and can be expected to continue to do so over the 10-year period of this study. As Figure 7 illustrates, TLRs have increased dramatically over the last seven years, from a few per year in 1997 through 1999, approaching 10 per year in 2000, doubling to over 20 per year in 2001 and 2002 and doubling yet again in 2003 to over 50 per year. Increased TLRs are not necessarily an indication of a reliability problem, but they do indicate congestion, which can increase costs to consumers and cause operating pressure on the grid. It is generally understood in the industry that for any given level of utilization of the grid, more competent management and operators will improve reliability; conversely, the greater the utilization of the grid and the less coordination that occurs, the greater the chance of a mishap. TLRs can be viewed as one measure indicating increasing grid utilization or congestion.[15] Further analysis is needed however, of the duration and cost effects of these TLRs. TLRs may be subject to great variation for reasons unrelated to congestion, e.g., utility practices with respect to reporting of available transmission capacity, and are therefore sometimes considered inappropriate as a measure of reliability. Other transmission reliability and/or performance measures used in some rate plans focus on congestion as revealed in the differences in electricity prices between locations.

With incremental additions to transmission assumed to be approximately $3 billion per year,[16] the system may lag behind forecasted reli-

**Figure 7**
**Number of Level Five and Higher TLRs per Year**
**(January 1997-November 2003)**




Source: NERC, "2003 Long-Term Reliability Assessment," Figure 9

ability requirements for transmission investment. According to one recent electric industry reliability report, maintaining transmission adequacy at its year-2000 level would require a quadrupling of transmission investments over the next decade (adding almost 27,000 GW miles vs. the 6,000 GW miles planned). The cost of the new transmission capacity and replacing retired capacity would be about $56 billion this decade (or $5.6 billion per year).[17] This trend has significant implications and creates a serious concern for consumers. If the status quo continues and overall transmission investment for the next decade does not increase, the system in some parts of the country cannot be assumed to be able to meet growing consumer demands. Degradation of reliability and service quality, with increased risk of system outages will result.

In addition to reliability concerns, congestion impacts can be expected to increase. They will vary by location, by season, and/or by time of day – with persistent problems occurring in localized areas. As DOE's Electric Advisory Board noted in 2002, "Most transmission bottlenecks are only of local concern. Some, however, may affect large areas of the country or have national significance."[18] Congestion in certain regions can, based on an analysis of individual facts and circumstances have adverse implications for both the operations and economics of the system, resulting in higher costs to consumers. Operational impacts include increased application of TLRs and other techniques to maintain reliable operations, which can lead to higher power supply costs and/or service interruptions. Economic impacts can include higher costs due to the need to:

(1) Dispatch more expensive local generation because more distant, lower-cost generation cannot reach load;
(2) Make payments to keep otherwise uneconomic generators operating to maintain reliability; or
(3) Counter the price risk associated with the potential or actual exercise of market power in such places.

However, even with projected increased congestion occurrences, it is not always economical to "solve" the congestion problem. In general, the "economic" test is whether the incremental cost of transmission or other investments is less than the benefits to consumers in the form of reduced power costs. Where this is not the case, then allowing congestion to remain can be considered the economically efficient choice.

### *Reliability Implications for Consumers*

For consumers, the reliability implications of the continuation of current trends in transmission investment are significant, though they may not be immediately evident. Most of the effects described above relate to the stress and strain on the system as grid operators conduct their business under tightened operating conditions, rather than, for example, direct impacts on power supply costs or changes in service interruptions. While such operational pressure may tend to be the immediate symptom of any reliability problems resulting from the downward trend in investment in the system, there is serious concern that consumers in many regions will be negatively affected in terms of increased occurrence of involuntary outages, power quality problems,[19] and increasing costs in some areas affected by congestion. While the number of outages may not increase greatly, these conditions mean that the system has to operate flexibly and dynamically in ever more complicated conditions in order to avoid them. The increasing reliance on operator actions to manage a heavily loaded grid through an assessment of potential contingencies means that there is a diminished ability to respond to system emergencies. Therefore, consumers in certain regions will be exposed to greater risk of involuntary supply disruptions for reasons other than weather.

As Table 3 shows, residential consumers represent 87 percent of all electricity consumers nationwide,[20] but only 37 percent of energy consumption. For some residential consumers in some regions, exposure to reduced reliability will only be considered annoying or inconvenient. In other regions, where congestion at times is high

**Table 3**
**Energy Customers and Consumption by Sector**
**(2002)**

| | Customers | Energy Consumption |
|---|---|---|
| Residential | 87.32% | 36.59% |
| Commercial | 11.46% | 32.24% |
| Industrial | 0.45% | 28.08% |
| Others | 0.78% | 3.09% |

Source: EIA, *Electric Power Annual: 2002,* Tables 7.1 and 7.2, December 2003.

and overall system reliability is tenuous, residential consumers may be severely affected due to poor power quality and/or exposure to outages of short duration. While power quality and such outages are normally distribution problems, to the extent that the transmission system is under stress, these problems may be exacerbated. For a small portion of residential consumers – such as those with health concerns requiring equipment run on electricity or living in marginal economic conditions such that blackouts increase potential harm to them – a blackout could be life-threatening. In the event that system-related outages increase in frequency in the future, all residential consumers will be adversely affected.

For the remaining 13 percent of consumers that are not residential users, as indicated in Table 3, and whose electricity consumption represents approximately two thirds of total electricity use,[21] degradation in reliability will have severe consequences in terms of reliability and availability of power and exposure to direct outages. Because commercial and industrial customers make up the majority of total electricity consumption, reliability problems have a significant effect on the nation's economic productivity. In turn, given the service nature of the U.S. economy, increased risks to businesses that provide services upon which consumers rely, from telecommunications, to banking, to medical care, mean reliability problems for all consumers.

### *Economic Impacts*

While parts of the country can be expected to experience reserve levels consistent with reliability requirements, other regions will struggle with continued congestion and increasingly inadequate reserve levels. One can expect to see many signs of continuing reliability concerns in grid operations and long-term resource adequacy. Reliability and economic impacts of inadequate transmission are closely intertwined. The continuation of current low levels of transmission investment exacerbates the likely economic consequences of this situation for the long term, resulting in potentially severe consequences for consumers.

There are short-run surpluses of generation resources (primarily gas-fired generation) in many regions of the country, which, at least in the near term, put downward pressure on power production prices. However, these same surpluses lead to lower market prices for power producers and put financial pressure on owners of

resources such that they are unable to finance additional investments or maintain credit for ongoing operations, with potentially negative long-term consequences. This continued financial pressure – along with regulatory, political and institutional uncertainty over investment recovery prospects in both transmission and in generation markets – increases the concern that generation and transmission investment will not be made at levels necessary to meet future load growth. Nor will it accommodate replacement or upgrades of equipment that is increasingly stressed and aging. Today's financial and credit problems in the electric industry could also present problems in the long term with respect to fuel and power supply contracting, project financing, equipment and inventory maintenance, performance of routine tree trimming, and other operations and maintenance activities.

Investment financing may be available for utilities' "essential," reliability-related investments because regulatory treatment for recovery of the costs of reliability upgrades is more certain than cost recovery treatment for "discretionary" upgrades made primarily for economic savings alone. However, continued uncertainty about cost recovery and regulatory rules can lead to a lag in needed investment in the system for these economic purposes, raising congestion costs to consumers during a period when such upgrades would otherwise be economically efficient. These increased costs will put pressure on consumer rates. While rate caps and freezes may limit the degree to which consumers will see these costs in the near term, and rate case decisions and mechanisms will determine how market prices and investment costs are passed through to consumers, eventually they will pay the price in higher electricity costs for insufficient investment in economic transmission upgrades – i.e., those where the benefits of the upgrade in terms of reduced energy costs exceed the cost of the transmission investment itself.

In addition, the electric industry's increasing reliance on natural gas, which has demonstrated high price volatility and significant overall price increases, affects the level and direction of the trading of power within and across regions, and places increased demands on the grid. Together, these natural gas supply conditions contribute to higher and more volatile electricity costs to ultimate consumers, (as well as adding to the financial pressure on owners) and places further stresses on the bulk power system. The transmission system must be operated (and may have to be enhanced in the future) so that it can respond adequately to variations in fuel prices and availability. The impact of fuel price swings on consumers can be mitigated through access to a broad portfolio of fuels used for generation. Extreme weather conditions in recent years in many parts of the country – including the drought in the West and the "cold snap" in the Northeast – have led to dramatic changes in transmission flows due to reliance on volatile fuel supplies (e.g., hydro power) and on fuels with volatile prices (e.g., natural gas). Variations in transmission flows are also likely to increase in the future as more wind generation connects to the grid. There is evidence that increasing reliance on natural gas-fired generation, and the potential for the continuation of high prices, or future price increases and disruptions in availability, can have a tremendous impact on transmission flows and a negative impact on consumers.[22]

New uses of the transmission system, such as increased trading of power between regions, can also be expected to increase stresses on the grid. Short-term electricity trading can affect flows of power across the grid, in some cases creating or worsening transmission congestion or otherwise putting pressure on the transmission grid to perform in ways for which it was not originally designed.[23]

These reliability problems have consequences for overall national economic productivity, with considerable anecdotal evidence of the kinds of problems that can be and often are caused by outages, transmission bottlenecks, and poor power quality. The August 2003 Blackout and the outages during California's 2000-2001 electricity crisis are two examples of those costs. According to the study by the U.S.-Canada Power System Outage Task Force Report, over 50 million people were

out of power in the Northeast U.S. and Ontario, Canada as a result of the August 2003 Blackout. Lost customer load amounted to 61,800 MW of electricity and millions of work hours and billions of dollars in economic costs.[24] While the August 2003 Blackout was due to operational problems and not inadequate transmission investment, it provides an example of the consequences for consumers of any power disruption. Because of the interdependent nature of the gas, water, waste water, banking, and telecommunications systems that all depend on the electric power delivery system, stresses on the electric power system can have serious overall impacts on the nation's economy.

### *Economic Implications for Consumers*

There can be economic consequences of transmission congestion for consumers, in the form of higher cost power and possibly reduced reliability. Some of these consumer costs come in the form of "congestion costs" (i.e., costs related to power generation dispatched out of economic merit order as a result of the inability to access lower-cost power reliably due to transmission constraints, along with additional costs due to congestion such as the RMR contracts, referenced earlier, to keep uneconomic generation in operation). For example, FERC's Electric Transmission Constraint Study of December 19, 2001 calculated estimates of the consumer cost impacts of certain transmission-related constraints during the summers of 2000 and 2001. As seen in Table 4, these costs vary considerably among regions and across years. In some regions, congestion costs are minimal or non-existent, while in others, such costs are estimated to amount to tens of millions of dollars. The costs in the eastern parts of New York appear to be even higher.

While these congestion costs have been described here as consumer costs, in some cases, consumers do not feel the direct effects of such costs – at least in the short run. In many parts of the country that adopted retail customer choice (e.g., the Northeast and Mid-Atlantic States and California), policymakers accompanied retail choice with the imposition of rate caps, rate freezes, and "transition-period" rates, which have shielded many retail consumers for years from the effects of these real-time congestion costs and market inefficiencies. For several years in the past, and potentially continuing into the future, many residential and small business consumers may see no or only moderate electricity bill increases tied to operating inefficiencies or congestion costs in load pockets. As transition rate freezes and rate caps begin to expire in coming years, consumers may directly face more of these costs. Even rate caps, however, cannot protect consumers from the direct implications of an increasingly less reliable transmission grid and operating system in terms of exposure to unplanned outages of sometimes unknown and long duration.

As discussed previously, projections of planned future transmission investment are estimated to be approximately $3-$4 billion per year across the nation. This investment is primarily for what have been identified as needed reliability-related transmission upgrades. Assuming investment at this level for the nation as a whole, it is nonetheless likely to be the case that for some companies, their portion of this reliability investment may not be sufficient in size to trigger a rate case application and regulatory review. For example, for an electric company that invests in transmission at levels approximately equivalent to the transmission-related rates for the company's last rate case, the company's transmission-related rates may not change even with major new transmission investments; the company may be able to finance new transmission investment through the depreciation-related revenues in rates. In such an instance, consumers' rates would not change; even as their utility's out-of-pocket investment (and financing) in transmission occurs.

Given the small percentage of the total consumer electric bill that is attributable to transmission functions (e.g., recovery of return of and on investment in transmission) compared to the energy costs (i.e., costs of supply), consumers in some regions may face greater costs as a result of

**Table 4**
**Cost to Consumers of Transmission Constraints**
**(Million $)**

| Constraint | Summer '00 Cost | Summer '01 Cost |
|---|---|---|
| Southeast PA (PJM) | $10.8 | $16.0 |
| East NY (NYISO) | 724.7 | 64.6 |
| SW CT Interface (ISO-NE) | 8.4 | 4.0 |
| Northeast of Boston (ISO-NE) | 16.1 | 16.0 |
| Southwest MI (ECAR) | 0.0 | 0.3 |
| West VA/PJM Interface (ECAR) | 0.0 | 20.0 |
| Southeast West VA (ECAR) | 1 .5 | 3.0 |
| Central MO (MAIN) | 1 .2 | 0.6 |
| Central IA (MAPP) | 0.0 | 0.5 |
| East KS/MO Interface (SPP) | 0.0 | 1.7 |
| Central CA (CAI SO) | 20.0 | 0.6 |
| Southern CA (CAISO) | 77.6 | 0.3 |
| WY/ID Interface (WSCC) | 17.3 | 18.0 |
| Northeast AZ (WSCC) | 2.4 | 0.8 |
| Pacific DC Intertie (WSCC) | 7.5 | 0.0 |
| CA/OR Interface (WSCC) | 11 .0 | 0.0 |

Source: FERC, "Electric Transmission Constraint Study," December 19, 2001

a lower level of investment in transmission than they would from a higher level. This is due to the role that additional transmission capacity could play in reducing reliability problems, reducing congestion costs, enabling power trades among more market participants in a larger region. In such circumstances, additional transmission investment is clearly warranted. The Path 15 transmission line in California offers one such example. Estimates of its $306 million cost indicate that this investment will be recouped in annual energy savings in about four years.[25]

### *Environmental Impacts*

Environmental impacts are directly and indirectly tied to electricity generation and transmission.

Environmental impacts of power generation fall into two principal categories: emissions (most notably air emissions) and localized siting. Air emissions reductions from power plants stem largely from compliance with existing environmental regulations and policies.[26] According to the U.S. Energy Information Administration's ("EIA") current and near-term projections, major air emissions of sulfur dioxide ("$SO_2$") and nitrogen oxide ("$NO_x$") have decreased over the past decade. Figures 8 and 9 indicate that $SO_2$ emissions have declined significantly over the last 10 years and are expected to continue to decline slightly through 2025. $NO_x$ emissions have similarly declined over the last 10 years, but are expected to increase slightly through 2025. Carbon dioxide ("$CO_2$") emissions are also expected to rise gradually in the coming years. If the U.S. Environmental Protection Agency ("EPA") adopts its new proposed rule (the Clean Air Interstate Rule) that would require states in the eastern half of the U.S. to revise their state implementation plans so as to reduce emissions of $NO_x$ and $SO_2$, emissions will further decline beyond those shown in Figures 8 and 9.[27] $CO_2$ emissions, however, are expected to increase due to increasing generation output with emissions that are not subject to caps.

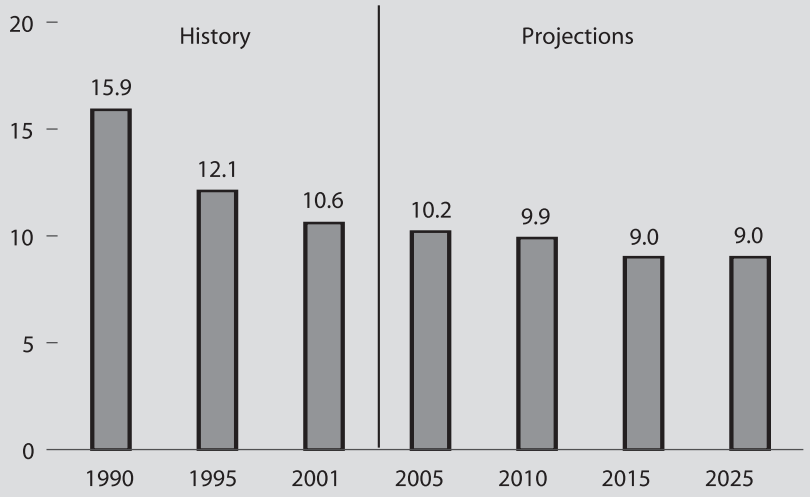
As noted earlier, the CECA Forum did not focus on the myriad of complex energy siting issues in this study. However, siting-related environmental impacts can be expected to occur from the fleet of new power plants and transmission lines in the permitting or licensing stage or under construction. Siting politics are likely to continue to be difficult, time-consuming and controversial – whether for new transmission facilities, new gas pipelines to meet demands of new power plants for gas, new combined-cycle or peaking projects, or wind turbines in offshore waters.

### *Environmental Implications for Consumers*

Particularly if emissions reduction programs are not implemented, consumers in those regions of the country that are not in attainment with EPA air emissions limits will face increasing exposure to the public health effects of air pollution (in the form of ozone and particulates) as $NO_x$ and particulate emissions from the electric power sector are increasing under current trends.[28] Coal-fired generation, in particular, is expected to remain high and to contribute to emissions of particulates, $NO_x$ and greenhouse gases related to global warming.[29] While the effects of carbon and other greenhouse gas emissions are global in their impact, to the extent that climate change is already causing more severe weather conditions, consumers in the U.S. are adversely affected. Moreover, given current trends that lead to increasing emissions, consumers will be adversely affected in the long term unless measures are taken to reverse these trends. Therefore, while the direct impacts of climate change are subtle and not readily visible in the short term, the implications for consumers are negative over time. The implications will especially be felt by those who live near areas adversely affected by sea level rise, or those who live in regions becoming more arid or wetter than normal, or in areas subjected to extreme weather conditions in a particular year.

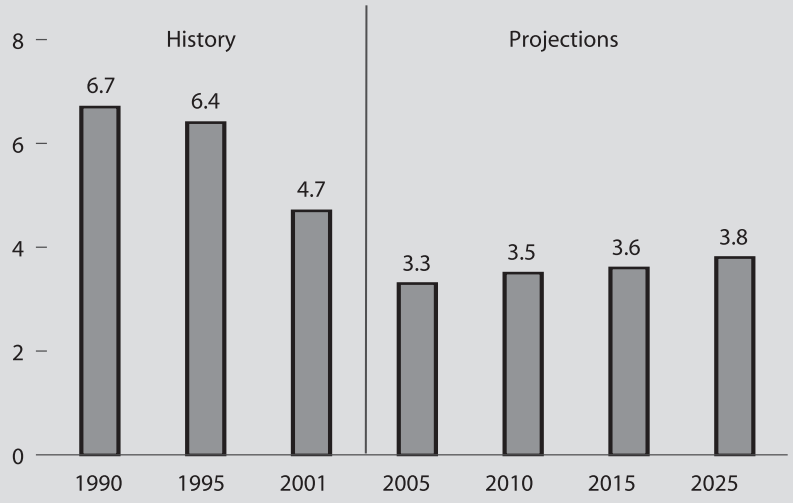
The implications of siting issues for consumers vary by location. Consumers who live near proposed transmission and generating facilities will perceive or experience impacts (such as visibility impacts, noise, traffic congestion, and so forth). Neighbors of proposed facilities generally oppose them and typically succeed in challenging or at least delaying such facilities. Without a process for fair consumer input into siting decisions, facilities, such as wind power, that could improve reliability and/or reduce costs and specific environmental impacts may not be built in a timely manner, therefore increasing reliability risks, economic costs, and in some cases environmental impacts on the whole. Siting controversies can also discourage investment, which can delay construction of needed and cost-effective transmission infrastructure and thereby adversely impact consumers.

**Figure 8**
**Sulfur Dioxide Emissions from Electricity Generation**
**(1990-2025, million tons)**




Source: EIA, *Annual Energy Outlook 2004,* Figure 119, p. 105.

**Figure 9**
**Nitrogen Oxide Emissions from Electricity Generation**
**(1990-2025, million tons)**




Source: EIA, *Annual Energy Outlook 2004,* Figure 120, p. 105.

### *National Security Impacts*

To the extent that the transmission system is operating closer to its technical limits than it has done historically, it may be less able to respond in the event of a national security threat today than in the past. If current trends continue, demands on operators to manage constraints will increase. The need to be able to manage the consequences of a possible security threat adds to these demands. Current transmission investment trends do not always accommodate a significant amount of new investment in areas such as improving inventories of transformers and other critical equipment or in adopting technologies such as system monitoring (e.g., SCADA system elements) that could improve system security, whether on a routine round-the-clock basis or in response to an actual security threat. Therefore, with increasing stress on the system and without sufficient new investment being made in security-related measures, technologies, or practices, the ability of utility system operators to respond to an increased level of national security risk may be reduced over the 10-year period addressed by the CECA Forum's study.

### *National Security Implications for Consumers*

Consumers rely on electricity for virtually all underlying functions of the economy – from telecommunications, to banking, to traffic systems, to air traffic control systems, to medical systems. Consumers' quality of life would be severely disrupted if their electricity service, and the basic services that depend on electricity, were unavailable for an extended period of time due to terrorist-caused outages.

The August 2003 Blackout (and the 2004 hurricane season) clearly demonstrated the consequences for consumers of a widespread disruption of electricity service. In the instance of the August 2003 Blackout – which affected 50 million consumers – electricity service was disrupted for fairly short periods of time, in part because the causes were related to operations. While system operators anticipate that generation and transmission equipment may be damaged following a blackout event, even when it is due to operational factors, actions that destroy a large amount of significant physical infrastructure could disrupt service for considerably longer periods of time, with correspondingly greater consequences for consumers. Even a cyber attack could require substantially more recovery time than the August 2003 Blackout. Changes in practices with respect to the availability of system data may be required to help protect against this latter type of event and most regions are in the process of updating their practices in these areas in response to future security concerns.

One can imagine the array of basic services that could be disrupted for short as well as extended periods of time as the industry repaired the equipment on the grid. For example, ATM machines, telecommunications systems, traffic signals, and basic electricity supply to homes and businesses not served by back-up generation, might not be available for extended periods of time. There would be severe hardships for consumers and for the economy as a whole as a result of such circumstances.

Protecting against the consequences of widespread and prolonged disruptions of service will require investment in enhancements to the transmission system and changes in practices for purchasing and maintaining inventories of critical components. The tradeoff for consumers involves balancing the cost of these investments against the likelihood and consequences of a security threat. Costs to upgrade the system (e.g., maintaining adequate inventories of transformer equipment at readily available locations, making system monitoring improvements, adding technologies that enable the grid to be operated reliably closer to its technical limits – for example, by increasing system transfer capability) represent an insurance policy against the harm from such unlikely events. Certainly some of these vulnerabilities can be reduced if additional transmission investment is made to improve the reliability and economics of the system. Since the terrorist attacks of September 11,

2001, consumers have been more focused on the need for enhanced national security. One means of meeting this need is by investing in "insurance" upgrades to the transmission system. In some cases, these investments could benefit consumers by enabling more efficient utilization of the grid even under normal conditions.

## CECA FINDINGS

The implications for consumers of a continuation of current trends in transmission investment could include threatened reliability and increased costs. Consumers will be ill-served if steps are not taken to remove disincentives to transmission investment that can bring benefits to consumers. The system is stretched to its capacity in many parts of the country due to a declining trend in transmission investment coupled with an upward trend in consumer demand over the last decade.

In some regions of the country, transmission owners have taken measures to alleviate this problem by investing in new wires and efficiency improvements. Notwithstanding these actions, the result of the overall downward trend in investment is that in many regions the system is operating under increasing stress. Unless significant changes are made that increase investment in the transmission grid so that reliability is maintained at the level of accepted standards and congestion is reduced where the benefits exceed the costs, consumers will be adversely affected by further degradation of service in terms of increased likelihood of system outages and higher costs.

Specifically, the CECA Forum makes these findings with respect to the implications for consumers of the continuation of current trends in transmission investment. These findings support the conclusion that policymakers, regulators, and transmission owners and operators must act now to ensure that the transmission system will be maintained and, where necessary, enhanced in a manner that will make it robust enough to continue to meet reliability standards, changing consumer demands, continuing operational challenges and to respond to national security threats. A strong transmission system is a key link in the critical infrastructure system of the nation. The CECA Forum offers the following findings:

### *Findings on Reliability Impacts*

In some regions, consumers will have reliable electricity supplies, consistent with the levels experienced in the past. However, during high demand periods and in some geographic regions, the risk of involuntary disruptions as the system is operated closer to the margins of reliable and safe operations will increase. In those regions and in load pockets where the system is operating close to its reliability margins, these conditions may not typically be visible to consumers, but uses of electricity at certain times (e.g., hours, seasons) may be more vulnerable to disruption, power quality problems and higher costs in light of these conditions on the grid.

### *Findings on Economic Impacts*

There may be adverse productivity impacts from reduced reliability resulting in increased costs, but electricity rates may be capped or consumers may be otherwise protected from higher electrici-

ty prices in the short run. These costs may be experienced by consumers in terms of reduced reliability and fewer options for supplies in competitive markets. In the long run, there will be pressure to increase rates to cover these costs.

### *Findings on Transmission Effects on Electricity Costs*

Costs of electricity service will continue to differ regionally. In general, consumers in the areas that now enjoy relatively low electricity prices (e.g., parts of the South, parts of the Pacific Northwest, the Midwest and Rockies) will continue to do so compared to other areas (e.g., the Northeast and California) that do not have access to low cost supplies. This price differential is due in part to such factors as inter-regional differences in generation and fuel resource availability (e.g., the age of power plants, the type and availability of fuel), as well as transmission-related barriers.

In regions with higher prices resulting directly and indirectly from transmission-related bottlenecks or constraints, consumers (through their load-serving entity) may have less access to economical sources of power on the constrained side of transmission boundaries. These consumers may not be paying for new transmission investment but they are paying higher prices for electricity supplies. In these instances it may be less costly to relieve the transmission bottleneck. The economic attractiveness of relieving the constraints will vary by local circumstances.[30]

### *Findings on Cost Allocation*

Even in some instances where there may be a net gain to society associated with new transmission investment; there can be winners and losers as a result of such investment, in terms of impacts on electricity costs, siting-related impacts, and impacts on electricity rates. Where there is a misalignment between the real or perceived beneficiaries of new investments in transmission and those who pay the direct or indirect costs of these investments, there will continue to be resistance to making and/or allowing cost recovery for such investments.

### *Findings on Need for Further Coordination of Gas, Coal and Other Generating Fuels with the Electricity Systems*

Overall coordination of information about gas resources and supply delivery systems with electricity system operations, including understanding the impacts of fuel prices and availability, is essential in order to avoid risks of major electric power interruptions, and must be taken into account in transmission system planning. The impacts for generation availability that might result from the interruption of a gas transmission line need to be analyzed and taken into consideration in planning for electric system reliability, including transmission needs. Coordination is more critical in regions that rely more heavily on gas-fired generation than others. Similarly, systems that rely heavily on other sources of generation must plan for possible disruptions in those supplies, e.g., systems reliant on hydroelectric generation must plan for the consequences of drought.

## Notes

1 DOE, *National Transmission Grid Study,* 2002, p. D-18.
2 DOE, *National Transmission Grid Study,* 2002, p. C-10.
3 Eric Hirst, *U.S. Transmission Capacity: Present Status and Future Prospects,* August 2004, p. 7. Hereinafter, "Hirst, August 2004." This Hirst report notes that there are data inconsistencies and quality issues over this time period which may account for some of the variations seen, p. 5.
4 Hirst, August 2004, p. 9.
5 DOE, *National Transmission Grid Study,* 2002, p. C-2, cites a figure of $3 billion and the Hirst report cites a figure of $3.6 billion.
6 Hirst, August 2004, p. vi.
7 NERC, *Long Term Reliability Assessment 2004,* p. 33.
8 "Reliability Must Run" or "RMR" contracts refer to contracts with uneconomic generators that are needed for reliability purposes. These contracts are intended to provide their owners with sufficient revenue to keep them in operation where market prices are too low to do so.
9 "Each RTO would be required to provide a forum for the participation of state representatives in its decision making process. We refer to this forum as a regional state committee. And we do not envision these committees as mere debating societies. Instead, the regional state committees would actually determine the regional proposal for a number of critical implementation issues" (FERC, "Remarks by William L. Massey, Commissioner," May 1, 2003). See also, FERC, Notice of Proposed Rulemaking, 100 FERC ¶ 61,138 (July 31, 2002) p. 115.
10 DOE, *National Transmission Grid Study,* 2002, p. D-2.
11 For more detail on differences by region, see NERC's long run, national and regional reliability assessments: NERC, *Long Term Reliability Assessment 2004.*
12 See NERC, *Long Term Reliability Assessment 2004,* for region by region information and greater detail.
13 DOE, *National Transmission Grid Study,* 2002, Papers A and B.
14 NERC Policy 9, Reliability Coordinator Procedures, June 15, 2004 (see http://www.nerc.com/~oc/pds.html).
15 There are 6 levels of TLRs: Level 1 involves notifying reliability coordinators of potential security limit violations; Level 2 involves holding interchange transactions at current levels to prevent violations; Level 3 involves reallocating and curtailing transactions to allow higher priority transactions or to mitigate violations; Level 4 involves reconfiguring the transmission system to allow certain transactions to continue; Level 5 involves reallocating or curtailing transactions to allow higher priority transactions to begin or to mitigate security violations; and Level 6 is Emergency Action. NERC, "Transmission Loading Relief (TLR) Procedure Logs" (see http://www.nerc.com/~filez/Logs/tlrlevels.html).
16 DOE, *National Transmission Grid Study,* 2002, p. C-2.
17 Hirst, Eric and Kirby, Brendan, *Transmission Planning for a Restructuring US Electricity Industry,* June 2001.
18 DOE, *Transmission Grid Solutions Report,* 2002, p. 5.
19 While power quality problems are generally regarded as a distribution system more than a transmissions system issue, the degradation of the transmission system would likely exacerbate them.
20 EIA, *Electric Power Annual: 2002,* December 2003, Tables 7.1 and 7.2. Hereinafter, "EIA, *Electric Power Annual: 2002.*"
21 EIA, *Electric Power Annual: 2002,* Tables 7.1 and 7.2.
22 ISO-NE, *Interim Report on Electricity Supply Conditions in New England during the January 14-16, 2004,* May 10, 2004. Hereinafter, "ISO-NE Cold Snap Report, 2004."
23 U.S.-Canada Blackout Report, 2004.
24 U.S.-Canada Blackout Report, 2004.
25 Swidler *et al.,* 2004; "ISO Board of Governor's Approves Path 15 Upgrade," (press release) June 25, 2002. Another example is NStar's proposed 345 kV line into Boston (See Commonwealth of Massachusetts, Environmental Notification Form, "NSTAR Electric 345 kV Transmission Reliability Project.").
26 Redispatch of generation because of transmission constraints also affects air emissions and may cause them to increase or decrease. The overall impact over the study period is not expected to be significant.
27 See EPA proposed Clean Air Interstate Rule (http://www.epa.gov/interstateairquality/rule.html), December 2003.
28 Though there are other sources (such as transportation sources) of emissions of particulates and NOx and causes of high ozone levels and other poor air quality, the electric power sector remains a significant source of emissions.

29 EIA, *Annual Energy Outlook 2004 with Projections to 2025,* p 103. Hereinafter, "EIA, *Annual Energy Outlook 2004*."

30 Relieving transmission bottlenecks can also have the effect of reducing other energy prices, especially natural gas, by allowing generation from other fuel sources to displace natural gas generation, which will reduce natural gas prices for all consumers.

Chapter 4

# Current Transmission Planning and Operations Practices and What They Mean for Consumers

## Current Transmission System Planning and Operations

The CECA Forum analyzed current practices and policies for regional transmission planning and operations. The Forum focused its analysis on how these practices and policies affect consumers. CECA's review in Chapter Three of current trends in transmission investment revealed that uncertainty about transmission planning requirements and responsibilities is a deterrent to investment. As the analysis in this Chapter will show, effective regional transmission planning is critical to the maintenance of a robust transmission system. As part of its investigation, the CECA Forum also reviewed transmission operations requirements and practices in various regions of the country. The review of operations was more cursory than the review of planning, in part because of the larger role played by consumers in the planning process as compared to transmission system operations. As discussed here in greater detail, consumer input early in the transmission planning process is important to ensure that consumer needs are met. Consumer participation will also increase the likelihood that transmission projects that provide benefits to consumers will enjoy local support. Consumers' interest in transmission operations is less about participation than it is about having a system that assures reliable operations. The August 2003 Blackout shows the importance to consumers of such operational assurances, since the examination of the Blackout conducted by the U.S.-Canada Power System Outage Task Force concluded that the blackout was due to operations and maintenance issues.

The CECA Forum conducted its review of transmission planning and operations on a regional basis, recognizing that regulatory frameworks (e.g., restructured or organized markets v. traditional regulated markets), institutional structures (e.g., RTOs, ISOs) and industry organizations (i.e., vertically-integrated utilities v. transmission and distribution companies v. independent transmission companies ["ITCs"]), and consequently planning policies and practices differ by region. The variety of market frameworks, institutional structures and organizations make coordinated regional transmission planning essential to ensure that the transmission system is adequate to meet consumer needs.

Recognizing that the borders of centrally organized wholesale power markets[1] may not coincide with the borders of NERC's reliability regions, the CECA Forum's analysis of planning and operations practices examined most of the principal, centrally-organized markets – ISO-New England ("ISO-NE"), the New York ISO ("NYISO"), PJM Interconnection ("PJM"), the Texas wholesale market operated by the Electric Reliability Council of Texas ("ERCOT"), and the Midwest ISO ("MISO"). The existing and proposed ISOs and RTOs are shown in the map in Figure 10.

The CECA Forum's review also examined the NERC regions that do not contain centrally organized markets, which include the Florida Reliability Coordinating Council ("FRCC"), the Southwest Power Pool ("SPP"), the Southeastern Electric Reliability Council ("SERC"), and the Western Electricity Coordinating Council

("WECC").[2] The CECA Forum used its review to identify key elements of planning and operations processes, across regions, that most effectively enable consumer needs and views to be taken into account. The boundaries of the NERC regions are shown in Figure 11.

### *Scope of Analysis*

The CECA Forum conducted research and analysis of transmission planning practices in the organized markets and NERC regions.[3] The results of this research are summarized in Table 5. Based on this analysis, the CECA Forum identified common themes important to consumers and attempted to identify both best practices and deficiencies in current approaches to transmission planning. It also examined operational rules and practices. There are considerable regional differences, more so with respect to planning than operations. In particular, the transmission planning process differs from regions with centrally organized wholesale markets, to regions in which the vertically-integrated utility model has persisted, to regions where hybrid markets[4] are developing.

Generally, the transmission planning process tends to be more transparent and allow for more consumer input at an earlier stage in the centrally organized markets; however, even across the regions with centrally organized markets, there are significant differences in planning practices. The biggest differences relate to the extent to which, and how, the planning process considers upgrades for economic as well as reliability reasons.[5] Regions also vary according to the manner in which transmission planners, providers, and owners take into account "non-wires" options[6] – recognizing that these options are complements to and not substitutes for transmission in many instances. Likewise, cost recovery and allocation practices and policies differ by region.

This Chapter includes a discussion of how cost recovery and allocation practices affect the speed and effectiveness of the transmission planning process and investment. Notably, and not surprisingly, where the rules for transmission planning are unclear, transmission planning proceeds more slowly and investment may be delayed. Further, cost allocation and cost recovery issues can be significantly more complicated when regulators in multiple states are involved. Common themes and differences in transmission planning and operations are described in greater detail in the following section.

## Analysis of Regional Transmission Planning and Operations

### *Planning*

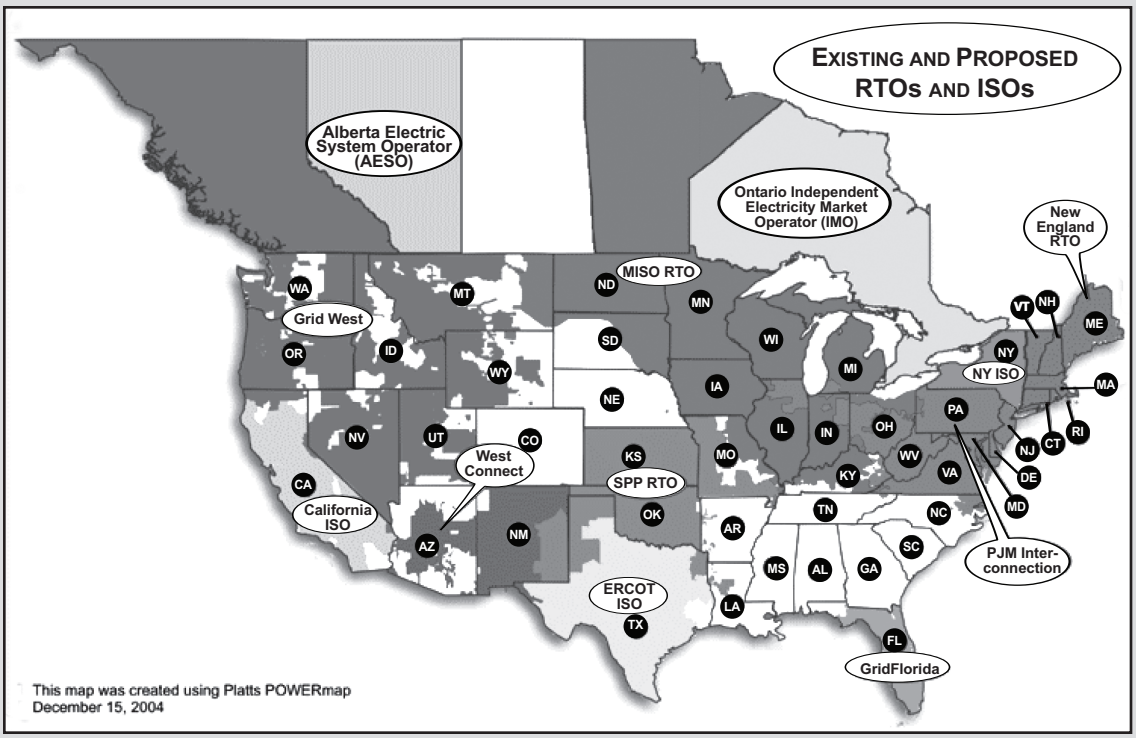
The most salient regional differences in transmission planning practices pertain to coordination and responsibility for transmission planning, treatment of reliability versus economic upgrades, regulatory roles, consumer input, and cost recovery and allocation.

#### *The Regulatory Role in a Multi-State Context*

State and federal regulatory policies and frameworks, including planning requirements, cost recovery and siting authority, affect transmission planning and investment, and uncertainty about their respective jurisdictions can hinder timely action on transmission enhancements that benefit consumers. Interstate coordination of transmission planning is a challenge for every region, with the possible exception of ERCOT, which is electrically isolated from the rest of the grid and lies completely within the borders of one state.

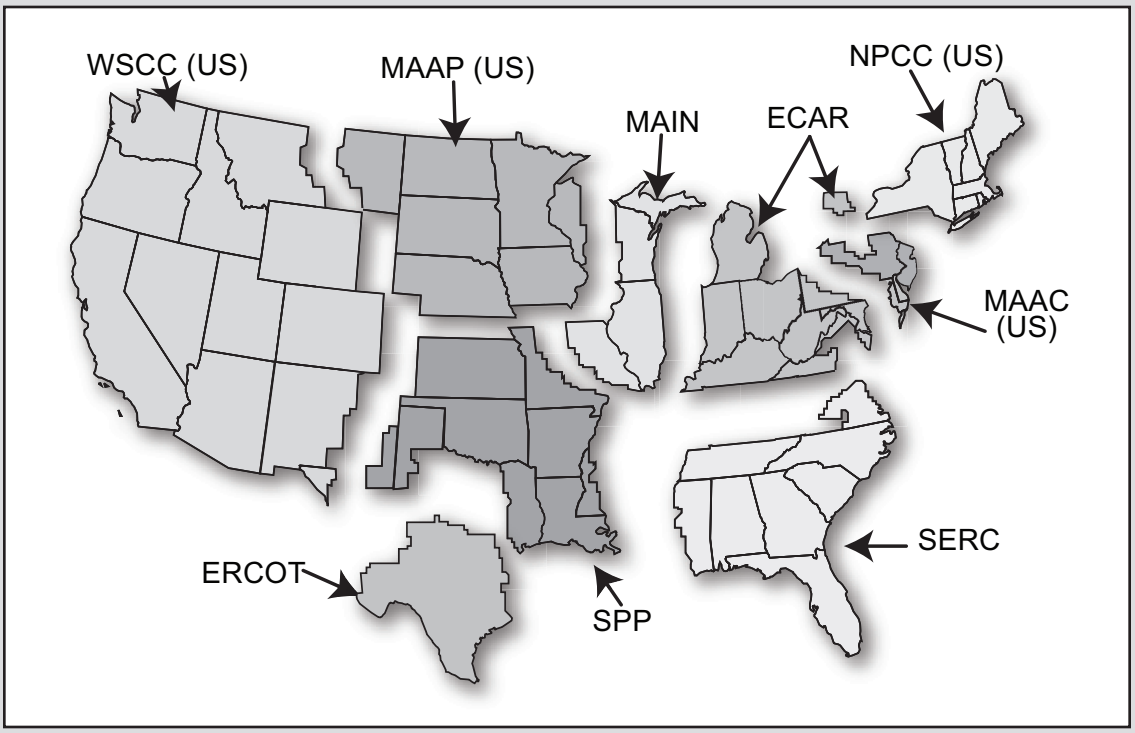
Interregional coordination is an even larger concern. In general, state public utility commissions are responsible for advancing the interests of their states and not of the region. Consequently, individual state public utility commissions have the ability, and understandably may have the incentive, to question the necessity for or delay approval of transmission expansion projects

**Figure 10**
**Existing and Proposed ISO/RTO Configurations**




Source: FERC at http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp

**Figure 11**
**North American Electric Reliability Council Regions**




Source: http://www.bydesign.com/fossilfuels/crisis/html/NERC_regions_map.html

**Table 5**
**Transmission System Planning: Review of Regional Transmission Planning by Region**
**(As of July 19, 2004)**

| | RESPONSIBILITY FOR REGIONAL PLANNING | | | Consumer Input | Cost Allocation/ Recovery |
|---|---|---|---|---|---|
| | Coordination | "Economic" v. "Reliability" Upgrades | Multi-State Regulatory Role | | |
| **ERCOT** | Contains an organized market. Planning is done through the ERCOT ISO, which is regulated by the Texas PUC (outside of the control of FERC). Regional Planning Groups (RPG) are responsible for reviewing proposals. | ERCOT does not consider economic upgrades in planning process. | ERCOT, located entirely within Texas, is electrically isolated from the rest of the country. Texas state regulators participate in Mid-America Regulatory Conference (MARC). | Consumers are represented through the Regional Planning Groups, and during the Certificate of Conveniences and Necessity process. All projects must be approved by the PUC. Consumers can only appeal through the courts. | Costs of transmission projects are recovered by rates determined by the PUC. |
| **FRCC** | No centralized planning process, with each individual utility responsible for planning. FRCC consolidates plans and does assessments analysis. FRCC has no RTO or RPG. | FRCC does not consider economic upgrades in planning process. | FRCC coordinates some cross-regional planning with utilities in Southeastern Association of Regulatory Utility Commissioners (SEARUC). | Consumers have input only through individual utilities. | No uniform methodology. Each utility provides tariff provisions, with judgments made on a case-by-case basis. |
| **ISO-NE** | ISO-NE is responsible for regional planning. ISO-NE gathers information from the Technical Advisory Committee to compose the regional transmission expansion process (RTEP). The RTEP takes into account multi-regional considerations. Region has RPG. | ISO-NE does not distinguish between economic and reliability upgrades in cost allocation. However, does classify projects as being for economic or reliability purposes, also has an "other" category. | State regulators participate in New England Conference of Public Utility Commissioners (NECPUC). | Consumers have input through the Transmission Expansion Advisory Committee (TEAC). | For reliability and economic upgrades, cost allocation is pool-wide for regional projects and local for local projects. Upgrades due to generator interconnections are funded through participant funding. |
| **MISO** | MISO is an RTO. MISO relies on the planning process of its members, but is developing its own planning capability through the Regional Expansion Criteria and Benefits Task Force (RECB). The region has an RPG. | The RECB is developing the planning process for both reliability and economic upgrades. MISO evaluates "projects of commercial interest" to take advantage of the natural resources of the region. | Region has formal Regional State Committee (RSC), the Organization of MISO States (OMS). | Consumers can participate in regional planning through the Planning Advisory Committee (PAC). The PAC has no formal approval of projects. Consumers can provide further input at the utility/TO level. | The RECB is responsible for developing cost allocation proposals. FERC adopted MISO cost allocation measures in its pro forma generator interconnection rulemaking. |

**Table 5, continued**

| | RESPONSIBILITY FOR REGIONAL PLANNING | | | Consumer Input | Cost Allocation/ Recovery |
|---|---|---|---|---|---|
| | Coordination | "Economic" v. "Reliability" Upgrades | Multi-State Regulatory Role | | |
| **NYISO** | NYISO has developed a comprehensive planning process for reliability upgrades that will determine system reliability deficiencies and assess the ability of proposed projects of merchant generators and transmission entities to meet identified reliability needs. | NYISO is developing a formal plan for determining economic upgrades. NYISO sees economic upgrades as reducing wholesale prices or expanding the generator market. | Not applicable. | Consumers are able to provide input through open committee meetings. There is a NYISO Board appeal process in the NYISO Agreement. The proposed planning process includes additional dispute resolution procedures with certain issues to be decided by the NYPSC and other issues to be decided by FERC. | The NYISO's comprehensive planning process for reliability includes a beneficiaries pay approach to cost allocation, though the details are still to be determined. |
| **PJM** | PJM is responsible for planning in its footprint which spans the MAAC region and parts of the ECAR and VACAR regions. PJM prepares the RETP for the region, which is subject to broad stakeholder input. | Traditionally, PJM has had a "market first" approach to economic upgrades. PJM recently initiated a backstop process to identify and fund economic upgrades. | Regulators in the PJM footprint are discussing formation of an RSC. | Consumers give input into the planning process through the Transmission Expansion Advisory Committee. PJM meets with TEAC to present an updated RTEP and provide time for input. | The full cost of reliability upgrades are rolled into the transmission rates of TOs on a license plate basis, subject to any alternative rate proposals filed and adopted by FERC. Costs of economic upgrades are assigned to the cost causer with appropriate credits provided for any reliability upgrades that would have otherwise occurred. |
| **SERC** | SERC has no centralized planning process. SERC does reliability assessments of the region. Each state within the SERC region undertakes different planning and siting responsibilities. | SERC does not consider economic upgrades in its planning process. | SERC has no RSC. State regulators in region participate in SEARUC. | Consumers provide input through individual utilities. | Cost allocation/recovery is handled differently state by state. |

**Table 5, continued**

| | RESPONSIBILITY FOR REGIONAL PLANNING | | | Consumer Input | Cost Allocation/ Recovery |
|---|---|---|---|---|---|
| | Coordination | "Economic" v. "Reliability" Upgrades | Multi-State Regulatory Role | | |
| **SPP** | SPP is an RTO, responsible for regional planning. Region does do some coordination with MISO and Entergy. | SPP has two phase planning process: phase one requires reliability upgrades; phase two RTO recommends economic upgrades. | SPP has formal RSC. | Consumers can provide input through a regional planning summit that is held periodically. Consumers can also participate in SPP working groups, task forces and committees. | SPP is in the process of establishing an RTO region-wide rate of 33% for all approved upgrades. |
| **WECC** | WECC does not have ISO or RTO functions. WECC has Regional Planning Guidelines for project sponsors to meet while planning projects and has a rating process to provide protection for rating project capability. | CAISO is considering economic upgrades in its planning process. Rocky Mountain Area Transmission Study (RMATS) considers economic upgrades as all investments that have net economic benefits to the region and do not serve adequacy purposes. | WECC has no formal RSC, but region does have state-to-state coordination, particularly with CREPC (Committee on Regional Electric Power Cooperation) and the Seams Steering Group – Western Interconnection Planning Working Group (SSG-WI PWG). Some state regulators within WECC participate in Western Conference of Public Service Commissioners. | Consumers can provide input within WECC Regional Planning Process. | Project sponsors are responsible for cost recovery |

Source: Consumer Energy Council of America

needed to serve a larger area when these projects appear to impose disproportionate costs or other impacts on a more limited area under that state commission's regulatory jurisdiction.[7] To ensure that the integrated transmission grid is planned and built in a manner that advances consumer interests overall, policies that establish an appropriate balance between local and larger interests need to be developed and clearly articulated and adopted by all states involved.

Multi-state regulatory coordination varies by regions. To address interstate coordination issues, New England and the Mid Atlantic Area Council ("MAAC"), a NERC region covered by PJM, have long-established organizations of state regulators[8] that deal with issues of regional interest or impact. Their roles vary, ranging from providing a "sense of the region" on an issue to more formal intervention in federal regulatory proceedings. These regional regulatory organizations have worked most effectively in the past where the individual member states can agree on a course of action; they are likely to be less effective at resolving interstate disputes within a region.[9]

Regional State Committees ("RSCs") offer a great potential benefit if they provide an avenue for moving forward with a multitude of transmission issues. To do so, RSCs must develop and continue efficient processes for resolving interstate differences, and not simply add a layer of required intervention that makes consumer participation more difficult.[10] Early in 2004, state regulators in states covered by MISO established one of the first RSCs, the Organization of MISO States ("OMS").[11] New England filed for approval of a more formal RSC in the summer of 2004.[12] FERC also approved an RTO plan, including an RSC, for SPP.[13]

### *Consumer Input to the Transmission Planning Process*

Consumers' ability to have meaningful input into the transmission planning process is critical for ensuring that their point of view is taken into account in decision making about the need for and benefits of transmission enhancements. The ability of consumers to participate in the transmission planning process varies by region. In some cases, consumers can join other market participants on advisory committees early in the planning process; in others, consumer input can be provided only at later stages of siting or certification of need for transmission facilities. In this latter situation, not only do consumers have no opportunity to comment early on transmission owners' plans for upgrades, but there is no means by which they can raise the need for new investment themselves.

*Consumers' ability to have meaningful input into the transmission planning process is critical for ensuring that their point of view is taken into account in decision making about the need for and benefits of transmission enhancements.*

Consumers may be represented in these transmission planning processes in a variety of ways: as individuals (e.g., certain large customers); through representation by consumer advocates; or indirectly by entities such as transmission dependent utilities ("TDUs") which, like individuals, are also consumers of transmission services. TDUs are predominantly municipal or cooperative utilities in which consumers play a large governance role – either through their elected officials in the municipality or as members of electric cooperatives. As noted, an opportunity for consumers to participate in planning processes does not guarantee their ability to participate effectively in these processes.

For instance, the effectiveness of consumer participation can be diminished or eliminated altogether if numerous meetings, calling for regular attendance, are required. Such provisions strain the limited resources of consumer groups.

Similarly, effectiveness of participating in the planning process could be hampered if rules for expressing opinions or conveying positions on issues operate to limit the voice of stakeholders such as consumer groups.[14] To be effective participants in the transmission planning process, consumers must not only have access to the process but also need to have adequate information at their disposal and the analytic capabilities to use this information. The opportunity to participate on advisory committees may be rendered meaningless unless these provisions are also in place.

The CECA Forum found that consumers generally have more frequent and earlier opportunities to provide input in the regions with centrally organized markets. The transmission planning processes in these regions are also more transparent. For example, ISO-NE, PJM, and NYISO all have Transmission Expansion Advisory Committees ("TEAC") or their equivalent, which include consumer representatives as members of the TEAC. ERCOT has consumer representatives on its Board and Technical Advisory Committee.[15] MISO affords consumers a number of ways to participate in the planning process, including formal representation on its Planning Advisory Committee and the opportunity to participate in meetings of its Planning Support Group and Expansion Planning Group.[16] However, even though consumers are granted some input, the consumer representation constitutes only a small fraction of the total membership of these committees.

There are fewer formal opportunities for consumers to participate in the transmission planning processes in regions outside of organized markets. The opportunity for consumer participation begins in such processes with submission of expansion plans by the vertically-integrated utility to state regulatory authorities for certification of need and siting approvals. These expansion plans may or may not provide for consumer input or address consumer needs explicitly.

### *Regional Coordination*

Regional coordination refers to the degree to which transmission planning is undertaken on a regional versus a utility-by-utility basis. Coordinated regional planning is important for meeting consumers' needs given the integrated nature of the transmission grid. The state of the system on one part of the grid will affect other parts. Discontinuities or seams within and between regions can make planning to ensure reliability more difficult and can increase the costs of transactions across these seams, resulting in potential reduced reliability and higher costs to consumers.

The CECA Forum's examination of transmission regions found that the current or newly emerging organized markets, including ISO-NE, PJM, ERCOT, and, to a lesser extent, NYISO and MISO, have the most coordinated planning processes, although their levels of coordination vary. For example, MISO has a process that leans heavily on the planning processes of its members. In contrast, planning in SERC, SPP, and FRCC takes place mostly inside of vertically-integrated utilities with varying degrees of coordination between adjacent control areas and transmission systems.[17] With some notable exceptions, such as the Southern Company and Entergy Corporation systems in SERC, the geographic footprints of the vertically-integrated utilities tend to be smaller than those of the organized markets. Because of their size, very large, vertically-integrated utilities are likely to be able to internalize some of the benefits of more coordinated regional planning.

There are some exceptions to the rule that more coordinated planning tends to be associated with organized markets. For example, in the WECC, the Southwest Transmission Expansion Plan ("STEP") process is contemplating upgrades to transmission between the Desert Southwest and California and involves representatives from the California ISO and adjacent control areas. In

addition, the new Seams Steering Group-Western Interconnection Planning Working Group ("SSG-WI PWG") has developed a process for identifying transmission projects with broad regional benefits and coordinating with other sub-regional planning efforts such as STEP.

### *Planning for Economic and Reliability Upgrades*

As described previously in Figure 5, the policy debate on transmission investment often distinguishes between economic and reliability upgrades. However, transmission improvements often have characteristics of both. Specific regional approaches to reliability and economic upgrades are summarized in Figure 12. As Figure 12 illustrates, most of the organized markets (i.e., those with ISOs/RTOs) make a distinction between reliability and economic upgrades and have developed separate planning processes to address the need for such upgrades. ISO-NE appears to be the exception; in New England the regional transmission planning process addresses both reliability and economic upgrades.

Strictly speaking, economic upgrades are transmission improvements made primarily to reduce costs that may be caused by congestion, without necessarily being required to maintain reliability standards. Economic upgrades are generally undertaken when the projected costs of congestion exceed, in some cases by a pre-determined amount, the costs of relieving that congestion through either investment in additional transmission capacity or, in some cases, the implementation of what are often called non-wires options such as demand-side management or distributed generation ("DG").

By contrast, reliability upgrades are investments in the transmission system required to ensure that reliability standards are met or that quality service to customers can continue uninterrupted. Congestion or constraints on the transmission system may initially reveal themselves through a need for operational adjustments that lead to higher costs for consumers (e.g., as a result of dispatch of a higher cost generating unit within a constrained area rather than dispatch of a lower cost unit whose power cannot be delivered to the load in that area). As load grows and the system changes (e.g., generating units are retired or added), the constraint may grow to the point where operational adjustments are no longer adequate to ensure reliability, resulting in the need for a reliability upgrade. A typical example is that initially an aging, inefficient and expensive generator is required to be paid to stay in operation in a congested area to serve consumer load, so a transmission upgrade would provide an economic benefit. However, at some point the generator may reach the end of its technical life and be forced to be retired, in which case the upgrade becomes needed for reliability purposes. Consequently, in some instances, the difference between economic and reliability upgrades may be primarily one of timing – today's economic project becomes tomorrow's reliability project.

In the transmission planning process, distinctions between reliability and economic upgrades tend to be less notable where utilities remain vertically integrated and traditionally regulated with planning processes that address both types of upgrades. Transmission planning processes in organized markets tend to distinguish between economic and reliability upgrades and address them in separate analyses and processes. All of the regional planning processes examined in this study identify reliability upgrades, but they differ in terms of whether they specifically act so as to identify upgrades primarily for economic purposes.

One strand of the policy debate[18] suggests that "the market" will supply economic upgrades. In this perspective, when the projected costs of transmission constraints exceed the cost of relieving them, a market participant will step in to make the needed investment. This market-based approach depends on consumers, as well as potential transmission investors receiving accurate price signals (e.g., through locational marginal pricing[19]) about the real-time, location-specific costs of congestion. For multiple reasons, price signals, however accurate, may not provide sufficient incentive for the market to respond. A

**Figure 12**
**Specific Regional Approaches to Reliability v. Economic Upgrades**
**(As of November, 2004)**

**ISO-NE:** ISO-NE does not distinguish between economic and reliability upgrades. Any necessary upgrade costs are pooled through transmission rates or paid by generation owners. For the purpose of classifying projects, ISO-NE considers a reliability upgrade a planned project that maintains system reliability, while an economic upgrade is a planned project that reduces congestion costs or interconnection of new generation. Both kinds of upgrades projects are considered necessary projects, while elective projects are neither economic nor reliability upgrades.

**MISO:** MISO has defined reliability and economic upgrades more generally. Reliability upgrades are projects needed to provide and maintain transmission system performance within applicable reliability standards while meeting the ongoing service obligations to existing transmission customers. Economic upgrades are not considered necessary to maintain reliability of the system, and have a benefit of relieving congestion, potentially reducing cost of electricity to consumers. MISO is developing cost allocation mechanisms for the two types of upgrades.

**NYISO:** NYISO is in the process of developing a formal comprehensive planning process through its committee/governance process. NYISO has filed with FERC its initial planning process which considers reliability upgrades only, and has started work on developing an economic planning process. NYISO defines an economic upgrade as an upgrade made for economic purposes, such as to reduce the wholesale price of electricity on the receiving side of a congested transmission path, or to expand the market for generators located on the sending side of a congested transmission path, when such an upgrade would not be required to meet reliability criteria. Under the current NYISO Tariff Scheme, market participants can pursue economic upgrades in two ways: 1) a developer may propose and pursue a merchant transmission project under the NYISO interconnection process (i.e., NYISO treats a merchant transmission project the same as a generation project); or 2) one or more market participants may request NYISO to conduct studies to identify upgrades to increase the transfer capability of a congested transmission path at market participants' expense.

**PJM:** For reliability upgrades, PJM does a baseline reliability assessment taking into account proposed generation and transmission additions over the planning horizons, as well, as any generation retirement requests. If reliability criteria will be violated then transmission upgrades are proposed to restore reliability. Costs are allocated based on principle of cost causation. PJM initially proposed that economic upgrades (i.e., transmission upgrades not specifically needed to maintain compliance with MAAC Reliability Criteria) be market-driven - i.e., developed by market participants, such as merchant transmission developers or providers of load management services, in response to current and forecasted energy prices and price differences within the PJM region. FERC, however, determined that PJM should consider the need for economic upgrades in its planning process. As a result, PJM has developed a process to identify and evaluate the need for economic upgrades to comply with FERC's directive.

**WECC:** CAISO does not consider economic upgrades in its planning process, although it is developing a process to do so. The Rocky Mountain Areas Transmission Study ("RMATS") group considers economic upgrades to be transmission investments that provide net benefits to the region. These include facilities that do more than interconnect a generator, and that are designed to reduce bulk power cost in the Rocky Mountain States, and in the case of export paths, in West Coast markets.

Source: Consumer Energy Council of America

number of other economic and institutional factors may intervene. For example, the investor may not be able to capture the benefits of relieving the constraint for him/herself, because of market design or cost recovery rules, or more fundamentally, because of the fact that transmission investments reduce prices that were formerly high due to congestion and so the benefits are spread among all users. Sometimes less quantifiable costs, such as public opposition to siting, may deter investment. Consequently, many contend that market-based approaches are not likely to provide adequate incentives for investment in economic upgrades, and therefore may need to be supplemented with regulatory approaches.[20]

There is increasing recognition that the transmission provider's planning process may need to serve as a critical "backstop" when the market fails to produce needed investment, i.e., investment that is less costly than the congestion costs that it eliminates. For example, PJM has traditionally had a "market first" approach towards economic upgrades, but it has recently taken a more active approach. If market-based projects are not forthcoming to alleviate chronic congestion, there is now a backstop process in place to identify and fund such projects. ISO-NE's planning process identifies both reliability and economic upgrades, and while the NYISO planning process has focused exclusively on reliability upgrades, NYISO is now considering a new comprehensive planning process that may include economic upgrades. MISO relies largely on the local transmission plans of its member systems, but it also engages in some independent, longer-run planning which includes the evaluation of "Projects of Commercial Interest," that are purely economic (and regional) in nature. These projects take advantage of the natural resource endowment of the region, including coal and wind, and involve major changes to the configuration of the system. As an example, MISO is in the process of evaluating the kind of transmission expansion necessary to support major new wind farms in the Great Plains region.

Planning processes also vary in terms of how they take into account changes to the system and the range of options that can be considered to alleviate congestion. These processes tend to differ between regions with organized markets and those that have maintained the traditional, vertically-integrated utility model. In the latter circumstance where ownership of generation, transmission and distribution remains with a single utility and where planning takes place at the utility level, the effects of changes in generation (both retirements and additions) are explicitly addressed. Where vertically-integrated utilities continue to conduct integrated resource planning, "non-wires" options for relieving transmission constraints (e.g., demand-side resources and distributed generation) may also be directly considered in the transmission planning process. Both the decision making process with respect to new investment and the subsequent implementation process are simplified in the context of a single owner.

In regions with ISOs/RTOs with centrally organized markets, changes in the configuration of the electricity system also need to be addressed in the transmission planning process, but the process is more complex. Some of these RTO/ISOs have processes requiring generators that want to retire a specific power plant to notify the RTO/ISO, which has the authority to approve or deny the request for unit retirement depending on its impact on system reliability. This requirement provides the RTO/ISO as system planner with information it needs to conduct its transmission planning process, as well as the ability to ensure continued reliability by denying a request to retire a unit that is needed for reliability. These planning processes should also take into account the potential economic, as well as reliability, consequences for consumers of future generation retirements that can result in the need for expensive Reliability Must Run contracts to keep generators operating that are otherwise uneconomic to run.

Organized markets also have processes for identifying the need for new transmission investment. These processes take into account non-wires options that are being pursued by others (depending on the stage of development or cer-

tainty). For example, New England has been discussing the treatment in its transmission planning process of demand-side resources as a non-wires option that reduces congestion.

### *Transmission Cost Recovery and Cost Allocation*

#### Cost Recovery

Rules for cost recovery, including both federal and state regulations and the transmission pricing rules of specific organized markets, clearly affect the willingness of transmission investors to propose and build new projects. Cost recovery rules are important to consumers who want to be assured that the costs they are being asked to pay are warranted and reasonable. Consumers also benefit when cost recovery rules provide appropriate incentives to transmission owners and investors to plan for and build transmission facilities in a timely fashion for both reliability and economic purposes when the benefits exceed costs.

Where the traditional, vertically-integrated utility model predominates, the cost-of service model, with its comparative certainty of cost recovery, generally prevails. Under cost-of-service regulation, utilities are allowed to charge rates designed to provide them with the opportunity to recover their actual costs plus an administratively determined return on investment to compensate them for the risk of such investment. Depending on the individual utility's corporate structure, transmission investment costs may be recovered pursuant to federal or state ratemaking processes; companies with a separate transmission business unit have federal transmission tariffs; companies that provide transmission as part of bundled retail service (i.e., in combination with distribution and generation services) have transmission rates set by state regulators for such bundled service and by federal regulators for unbundled transmission service provided to others. Where a utility needs to demonstrate the reasonableness of an investment for its own customers, regulatory approval of cost recovery for transmission projects that provide benefits beyond the company's service territory may be problematic. Under cost-of-service regulation all ratepayers of a transmission owning utility pay the costs for that company's transmission investments.

*Cost recovery rules are important to consumers who want to be assured that the costs they are being asked to pay are warranted and reasonable.*

Transmission rates are also cost-based in regions with centrally organized markets, where costs may be recovered through what are known as postage stamp or license plate rates. Postage stamp rates recover embedded costs through a uniform charge applied to every unit of load served on a given system, with the tariff designed to cover the costs of all transmission assets of multiple owners. New transmission investment may be rolled in, with all consumers on that system paying the costs of transmission investments based on their levels of electricity usage, whether or not their particular usage may have triggered the need for a particular investment. License plate rates recover the costs of a given transmission owner through charges levied on the end users served by that transmission owner, rather than the system as a whole. ERCOT is unique among the organized markets in terms of the extent to which it relies on postage stamp rates; there, even generator interconnection costs are recovered through postage stamp rates.

In organized markets based on locational marginal pricing, entities which build transmission, including interconnecting generators, may recover some of their costs through rights associated with the financial benefits (or costs) associated with congestion rents. These transmission rights have different names and sometimes different particular attributes in different regions. In the market administered by the NYISO, these rights are called Transmission Congestion Contracts, or TCCs. In PJM and ISO-NE markets, these rights are called Financial Transmission Rights or FTRs.

(To simplify, these kinds of rights are referred to as FTRs in this discussion.) FTRs entitle their holders to the difference in energy prices (i.e., congestion "rents") between two different locations. (For example, a 1 MW FTR between location A and location B entitles the holder to the difference in the hourly locational prices at A and B in each hour (i.e., $Price_A - Price_B$). Transmission expansions typically lead to an increase in capacity, and by extension in the number of FTRs that can be supported by the transmission system. Transmission investors may be granted some share of these increased FTRs. Alternatively, the new FTRs may be auctioned, and transmission investors may share in the auction proceeds, i.e., the investors may be granted Auction Revenue Rights.

The value of FTRs fluctuates with transmission usage and relative energy prices between locations. Congestion between two locations may lead to large locational price differences and hence increases the value of FTRs between those locations. Locational marginal pricing or LMP can identify the potential ongoing costs of transmission-related congestion, a portion of which may be alleviated by installation of a given transmission project. Analysis of the impact on congestion costs of a particular new project can help enable load serving entities or others to determine whether they want to fund such a project, given its costs relative to its ability to reduce congestion-related costs. However, while transmission investment sometimes eliminates or significantly reduces the congestion at which it is aimed, it can also result in lowering the value of FTRs, because of the lower congestion rents in the future. In fact, locational marginal prices and congestion rents can change – up or down – significantly in the future for a variety of reasons. On the margin, therefore, locational electricity prices provide appropriate price signals about where new transmission investment is needed to reduce congestion, but relying upon FTRs is still not likely to create incentives for investments in transmission. Some argue that to better align incentives to reduce the cost of congestion, FTRs should be allocated to load serving entities. Other cost recovery and cost allocation principles may also be needed to ensure that the entities that benefit from an economic upgrade pay their fair share of its costs.[21]

### Cost Allocation

Cost allocation policies determine which consumers pay for transmission enhancements. The issue of cost allocation is one of the most hotly debated transmission topics in policy circles today. Funding mechanisms range from "participant funding" to "beneficiaries pay" to "socialization" of costs. Under participant funding, a group of market participants are directly assigned the cost of a transmission upgrade required for their requested transmission or interconnection service, and the upgrade only occurs if enough participants are willing to fund it. Participant funding says simply that whoever pays for new transmission gets the economic benefit created by that investment. Strictly speaking, costs are not "allocated;" instead they are in effect "directly assigned," because participants agree up front to fund a project. They do not receive any credits in exchange for the newly created transmission capacity. Instead, participants receive financial transmission rights to any incremental transmission capacity created by the investment. Participants' ability to recover their investment depends on the value, if any, of those financial rights.

Under the "beneficiaries pay" approach to cost allocation, an attempt is made to identify the direct beneficiaries of particular transmission upgrade and directly allocate and charge the costs of that upgrade to those consumers who benefit from the upgrade. In this model, the decision to build is made by a central authority (such as an ISO/RTO), and the costs are allocated between market participants and consumers, taking into account the likely broad benefits of the transmission upgrade over its life. Such a funding approach is also called "socialization" of costs. As mentioned earlier, the beneficiaries of a particular transmission investment may evolve over time and as system conditions vary with changes in load, generation dispatch, weather, transmission line additions and outages, and other factors.

The "beneficiaries pay" model recognizes that some portion of transmission investments will improve reliability and so that portion of the investment costs are charged to all customers, with the remaining costs directly assigned to the market participants who benefit from and/or seek these investments. While the regional debates over cost allocation have historically focused on participant funding versus socialization, costs can be more closely aligned with beneficiaries through a variety of rate design and cost allocation mechanisms. Some regions are looking at different ways to assign costs on a sub-regional level.

Socialization of costs means allocating them broadly over all consumers in a region, or on a system, or of a transmission-owning utility. Socialization of costs takes into account the benefits provided by a particular investment to the transmissions system and its users and consumers and assumes that they benefit as a whole. It does not attempt to identify and assign costs to a small set of consumers who may benefit more directly from a transmission enhancement.[22]

Clearly, consumers are affected by cost allocation policies and will be concerned about whether they are being treated fairly and equitably under any particular allocation method. Cost allocation policies – and clarity about them – also affect incentives for transmission investment, which in turn affect consumers in terms of the timeliness and need for enhancements that will provide them with benefits. When cost allocation policies are unclear, transmission owners and investors may be reluctant to commit funds for improvements that will provide economic benefits to consumers, and may even hesitate to make needed reliability upgrades. The type of cost allocation mechanisms will also affect transmission owners' willingness to invest in improvements. Generally, mechanisms that spread costs more broadly to consumer beneficiaries and are embraced as needed by the transmission provider and its regulators are typically viewed as providing transmission owners with greater assurance of cost recovery. By contrast, economic upgrades or other enhancements needed by a set of direct beneficiaries will tend to be financed and developed only when that particular set of beneficiaries agrees to support the costs of such improvements through a binding financial commitment.

The CECA Forum's review of cost recovery and allocation policies and methods revealed that many regions are in the process of developing default cost allocation mechanisms for transmission expenditures to provide clarity with respect to allocation policy. Default cost allocation mechanisms set out in advance the rules for recovery of costs and can be used in the absence of an agreement among parties on who benefits from and should pay for an upgrade. A default cost allocation mechanism can facilitate the transmission investment planning and implementation process when it is generally accepted by those who will be paying the costs. Regulatory certainty about the durability of default cost allocation mechanisms is also important for assuring their effectiveness.

The development of default cost allocation mechanisms is typically more controversial for economic than reliability upgrades, at least in part because economic upgrades are not necessary to meet reliability standards. As discussed above, the distinction between economic and reliability upgrades is one that tends to be required in regions with organized markets that treat cost recovery differently for each. To the extent that the planning rules of some organized markets express a preference for participant funding of economic upgrades (i.e., requiring the costs of an upgrade to be funded by the market participants who benefit from it), a critical question involves what happens when market participants are not willing to fund the project. Many organized markets are now considering planning for and allocating the cost of economic upgrades using a "beneficiaries pay" approach. However, this leads to the issue of what happens if the beneficiaries cannot agree on a cost allocation scheme. If there are not clear, algorithmic cost allocation methods that are broadly accepted, then disputes can delay needed upgrades that have clear benefits for consumers.

A second question is how cost allocation is affected when an economic upgrade becomes a reliability upgrade over time. The CECA Forum did not identify any default cost allocation mechanisms that provide for the beneficiaries of an upgrade paying for it only as long as they are the only beneficiaries. With any such mechanism, the process of determining who benefits and for how long is likely to be extremely contentious (and virtually impossible to do with any accuracy going forward), leading to delays in investment, which would work to the detriment of consumers when these investments are needed for reliability purposes or to relieve transmission congestion where cost-effective.

Default cost allocation mechanisms, such as rolled-in pricing (a form of socializing costs), which tend to spread costs over large groups of consumers, may encourage investment by making it less reliant on an individual participant's decision, but may also raise other issues. Mechanisms that allocate costs broadly across all consumers may mute price signals to some consumers – who might otherwise undertake energy efficiency or distributed energy investments or take other actions to obtain needed power – and market participants who might otherwise invest in generation in higher cost locations if the costs of upgrades to address constraints in these areas are allocated to a broader group of consumers. While these localized investments may not provide the broader reliability and economic benefits of transmission enhancements, they may prove to be more cost-effective in certain instances.

In those cases, broader allocation of costs may lead to cost shifting and cross-subsidization. For example, consumers in uncongested areas may end up sharing the costs to relieve congestion experienced by consumers in more congested areas when it might have been more cost-effective to take action at a more localized level. This cost shifting may be relatively minor given that transmission accounts for a small percentage of a consumer's electricity bill – although the secondary effect of new transmission investment on the locational prices in markets with locational pricing might be larger. Determining the benefits of rolled-in pricing will require evaluating the trade-offs between facilitating investment and the potential for cost shifting. To the extent that transmission investments to relieve congestion in one area also may resolve reliability problems overall, default cost allocation mechanisms, such as rolled-in pricing, may be more appropriate.

There is a range in the cost allocation treatment of economic upgrades in regions with organized markets. New England has what amounts to default rolled-in pricing of economic upgrades. PJM policy is based on the "beneficiaries pay" principle, with rolled-in pricing only as a last resort. The PJM process identifies the need for a project to reduce or eliminate congestion costs. Following the identification of the need, the process allows a one-year window for voluntary proposals to build a project. If proposals are not forthcoming and PJM determines that a regulated transmission project is cost-effective, PJM can direct construction of the project and can allocate its costs to the cost causer in accordance with its tariff. As of the fall 2004, the NYISO has undertaken stakeholder discussions to develop a planning and cost allocation process for economic upgrades.

Similarly, there is variation in the treatment of costs for reliability upgrades. In PJM, the full cost of a baseline reliability upgrade is recovered through rolled-in rates. PJM recommends a cost allocation for the baseline upgrades based on which "transmission zone" benefits from the upgrade, even if the upgrade is not physically located within that transmission zone. If an upgrade benefits more than one transmission zone, PJM recommends a cost allocation based on the estimated benefits to each of the transmission zones. In contrast, in August 2004, the NYISO filed a transmission reliability planning process with FERC that adopts the principle that beneficiaries pay for reliability upgrades rather than consumers where the upgrade is physically built (i.e., the customers of the transmission utility doing the construction). In New England, the costs of reliability upgrades of regional facilities are generally rolled-in, or shared, on a pool-wide or regional basis.[23]

MISO's Regional Expansion Criteria Benefits Task Force ("RECB") is developing default cost allocation criteria for all types of transmission expansions, including generator interconnections, reliability upgrades, and economic upgrades.

Even if clear cost allocation principles are developed in multiple regions, state and federal regulatory policy with respect to cost allocation and cost recovery will affect incentives for transmission investment. Regulators may be unwilling and/or unable to commit in advance to default cost allocation criteria, and state regulators in particular often perceive an obligation to review projects on a case-by-case basis.

## Operations

In its review of transmission operating standards and practices, the CECA Forum noted, among other things, that the August 2003 Blackout and its causes dramatically demonstrated the impact on consumers of utility system operations. As the transmission system is increasingly stressed, operators will face greater challenges as they work to ensure the reliability of the system. Recognizing that the CECA Forum principally focused on the need for transmission *enhancements* rather than *operations,* its review of transmission operations practices is less extensive than its consideration of transmission planning, and the findings address process issues rather than specific operational requirements.

NERC is the voluntary association of ten regional reliability councils, whose members in turn include investor-owned utilities, public power systems, rural electric cooperatives, independent power producers, marketers and end-use customers in the U.S., Canada and a portion of Northern Mexico. Transmission providers have committed to follow NERC's standards and, in some cases, even more rigorous regional reliability standards. The standards pertain to a variety of operations and maintenance practices encouraged by NERC through a combination of voluntary commitments, public disclosure, peer pressure, and auditing. NERC's standards relate to such functions as system balancing, operator training, the coordination of outages, and recovery from emergency conditions including blackouts. There is limited inter-regional variation in the standards themselves, but there is significant variation in the entities that are responsible for performing the various functions defined in the standards. Evolving industry and organizational structures have resulted in NERC adopting a Functional Model, described below, that allows the elements of its standards to be assigned to the appropriate entity while accommodating a wide variety of electricity market structures and industry organizational forms.

### *NERC Functional Model*

NERC's policies and standards have traditionally centered on the control area as the significant operating entity responsible for compliance. As the industry has evolved, the homogenous structure assumed in NERC policies is no longer applicable. NERC has adopted a "Functional Model" that identifies reliability and other functions performed by market participant regardless of the prevailing market structure or regional differences. The model is being used to develop standards that provide clear accountability for reliability responsibilities over a wide variety of market structures and industry organizational models with emphasis on performance. The model identifies 17 separate functions that are important to reliability, along with the entity that performs each individual function. Explicit transmission-related functions include transmission operations, transmission ownership, transmission services, and transmission planning. Other functions include operating reliability, planning reliability, balancing, interchange, resource planning, generation ownership, generation operations, distribution, load-serving, purchasing-selling, market operations, standards development and compliance monitoring. Individual organizations can perform a single function or can combine several functions into a single organization.

The report of the U.S.-Canada Power System Outage Task Force, which assessed the causes of

the August 2003 Blackout, identified a lack of clarity regarding the identification of responsible parties for operations in the NERC policies.[24] The CECA Forum's review of regional practices shows a wide variety of structures in the regions. The development of the NERC Functional Model is intended to provide the clarity needed to ensure reliability while accommodating this variety of organizational structures and practices.

### *NERC Standards*

#### Real-Time Operations

NERC promulgates standards for the reliable dispatch and real-time operations of the bulk power system. These standards are outlined in the NERC Operating Manual.[25] Each of the regional reliability councils, and/or corresponding RTO/ISOs, have either supplemented the NERC Operating Manual with their own regional protocols and/or developed their own manuals consistent with the NERC standards. NERC's basic reliability standard requires that the system be operated so that it can survive the single largest contingency – known as "N-1" – such as the failure of a major generating unit or transmission facility.[26] NERC also specifies standards for operating reserves, frequency, and other standards related to real-time operations. Control area operators are responsible for following NERC standards for real-time operations. As mentioned above, the entities responsible for control area operations vary across regions. In the regions with centrally organized markets, the control area operator is typically the RTO/ISO.[27] Outside of organized markets, control area operators generally manage the resources of individual, vertically-integrated utilities, including municipal, cooperative, and investor-owned utilities.

#### Real-Time Monitoring

Real-time monitoring involves using telemetry along with other data and analytic tools, such as state estimators, to evaluate system conditions on a continuing basis. These conditions include power flows, various physical limits on transmission and other facilities, interchange with adjacent regions, and demand drivers such as weather. By necessity, the entity responsible for real-time operations also performs some real-time monitoring. In some regions, entities other than those responsible for real-time operations (e.g., individual utilities) perform some additional real-time monitoring functions. For example, MISO and FRCC both perform real-time monitoring functions for the control areas in their regions. The reliability coordinator performs a real-time monitoring function over a wide area, which in many cases is broader than individual transmission operators' monitors.

The sophistication of real-time monitoring varies across regions. Because the calculations necessary to construct locational marginal prices require a sophisticated dispatch model and detailed operational data, PJM and the other organized markets, such as New York and New England, which have implemented some form of LMP, may have analytic and informational advantages with respect to monitoring capabilities. For example, PJM, NYISO and the New England ISO have very complete dispatch models, and their Energy Management Systems are used to monitor and anticipate system conditions.

#### Emergency Operations

Preparing for and managing a wide variety of emergency operations is a critical element of reliability. NERC policies clearly define the roles and responsibilities involved. Entities are required to maintain emergency response plans, train personnel on emergency operations using simulator-based training, and conduct regular, realistic drills of emergency procedures. During emergencies, transmission operators are required to take immediate action to return the system to a reliable state following any event.

Addressing a wide-area emergency, such as a blackout, requires coordination across multiple control areas. The entity responsible for this coordination is the reliability coordinator. In regions in which control area footprints are relatively small, the reliability coordinator is usually a regional entity that is not a control area operator,

such as the local NERC coordinating council. In control areas with large footprints, such as PJM, the reliability coordinator is also the control area operator.[28] The reliability coordinator's responsibility in emergency conditions includes directing system restoration.

### Operations Planning

NERC policies establish the roles and responsibilities for operational, near-term planning, i.e., for the day-ahead, week-ahead, month-ahead, and seasonal time frames. In these time frames, the key issue of reliability of the transmission system involves the coordination of outages of both generation and transmission facilities. While individual transmission operators are responsible for their operational planning, the reliability coordinator is responsible for coordination of those individual plans over its area. In this manner the reliability coordinator is able to ensure that the impacts of one transmission operator's plan on another's system is understood and planned for. Again, as discussed above, under NERC's Functional Model, different functions may be performed by different entities.

Because smaller control areas tend to be more interdependent, in regions in which the footprints of control areas are small, such as FRCC, the entity that coordinates outages must have access to and consider information from multiple control areas. In regions where control areas are broad, i.e., generally those with centrally organized markets, outage coordination and other medium-term operational functions can be performed by the ISO/RTO that is also responsible for real-time operations. Where the control area is covered by a large vertically-integrated utility, operations planning may be performed, along with real-time operations, by that utility. Where different functions are performed by different entities, coordination among them is critical to reliable system operation.

### Training and Certification

Training and certification are important elements of providing reliability, an area emphasized and cited for audit and corrective action in the recommendations of the U.S.-Canada Power System Outage Task Force report on the August 2003 Blackout.[29] Regions differ in the manner in which they formalize and promulgate their specific procedures for implementation of the NERC operating policies. Some regions, such as ISO-NE, NYISO, and PJM, have their own operating manuals. Other regions, such as ERCOT, codify each specific operating procedure in their own documents. Yet other regions, such as SERC and FRCC, rely on the NERC Operating Manual.

For NERC certification, transmission operators involved in real-time operations must be adequately trained, adhere to NERC policies, and pass specific tests of their knowledge and capability. Regions differ with respect to their training practices for operations and some require additional region-specific training and certification. The majority of control areas have plans to conduct emergency drills and establish new system operator training programs. Only the MAAC region has system operators that are region certified.

### Enforcement

NERC has a Compliance Enforcement Program ("CEP") for NERC standards and a Compliance Enforcement and Certification Program ("CECP") for organizations and personnel that are designed to measure and enforce compliance with NERC and regional reliability standards. The programs' objectives are to encourage all market participants to adhere to the standards necessary to preserve the reliability of the interconnected bulk power system. In conjunction with the CEP and CECP, each NERC region has implemented its own regional compliance enforcement program. These programs were developed to achieve compliance with NERC reliability standards in the absence of federal legislation that would authorize mandatory compliance with NERC rules. Under the existing system, compliance with NERC standards is voluntary, and as such the CEP relies on simulated enforcement action.[30]

In addition to the CEP, NERC has entered into a

contract-based compliance agreement with nine of its 10 regional reliability councils. The agreement addresses a small subset (three) of NERC Operating Policies that apply to control areas and is therefore much narrower than the compliance program as a whole. The contract is between NERC and its member regions. The regions in turn must implement similar agreements with their members for the contract-based program to work. The tenth region has a separate regional contract-based compliance agreement.

Implementation of the compliance agreement by the regions has been mixed. Some regions have a full program in place; other regions have not been able to gain the approval of a sufficient number of their members to start a program. Two regions, WECC[31] and SERC,[32] now use financial sanctions, and other regions have indicated plans to do so. Some regions believe that non-monetary sanctions are preferable (NPCC), while others are looking to develop market-oriented sanctions. One region, MAAC, has its own contract-based enforcement program and has not signed the NERC agreement. While there are differences of opinion about whether and how a contract-based compliance and enforcement program should be implemented, there is agreement that a contract-based approach is not an adequate substitute for mandatory and enforceable reliability standards.

System operations have received increased attention in the wake of the August 2003 Blackout, due in large part to NERC's findings that the Blackout was essentially due to operational failures related to both operations planning and system monitoring.[33] Specifically, there has been significant consideration of giving NERC more formal legal authority to enforce its standards or, alternatively, creating a new federal regulatory entity to oversee transmission. However, Congressional efforts to pass authorizing legislation failed in the 108th Congress.

While distribution reliability and operations are overseen by state regulators – frequently through regulatory mechanisms tied to explicit performance metrics such as the System Average Interruption Duration Index ("SAIDI") and the System Average Interruption Frequency Index ("SAIFI")[34] – to date, similar performance measurements for transmission have not been specifically incorporated into performance-based ratemaking formulas for transmission.

Performance-based regulation has been discussed at the transmission level, but it has not yet been implemented to any significant degree. Some of these performance-based regulatory models are structured so that the transmission owner or operator has the discretion to make trade-offs between investments and changes to or enhancements in operations and maintenance practices so long as certain performance thresholds are met. Under such systems, transmission owners or operators are penalized if performance standards are not met and have the ability to share in the benefits to consumers if standards are exceeded.

Some of the interest in performance-based regulation is driven by the belief that it will prove more effective at encouraging utilities and transmission owners and operators to improve transmission services in a manner that maximizes benefits to consumers. However, concerns have been expressed that performance-based or incentive regulation may unreasonably reward utilities for actions they are already obligated to take. Clearly, the design of any performance-based regulatory mechanism is critical to whether it will deliver benefits for consumers. FERC is the regulatory authority that would implement such regulation for transmission in organized markets. In regions where the traditional vertically-integrated utility model prevails, the role of state regulators will depend on the degree to which they continue to regulate various aspects of transmission, including cost recovery for investment.

### Coordination

The previous discussion makes it clear that coordinated operation of the transmission system is more difficult when control of the complex interconnected grids is fragmented, even as it is clear that reliability is enhanced when operators take a global view of the interconnected transmission

system. NERC Policy 9 sets forth the roles and responsibilities of the reliability coordinator. The reliability coordinators have the responsibility for ensuring reliability of the bulk electricity network. They are responsible for maintaining a broad view to ensure that, even in those areas where transmission operations are geographically fragmented, the operations remain coordinated and reliability is maintained.

The NERC regions differ significantly in terms of the fragmentation of operation of the transmission system. PJM maintains centralized control of a transmission system with a large and growing geographic footprint. Similarly, the NYISO is the reliability coordinator for only its own control area, as is ISO-NE, but they have limited geographic footprints, although there is a high degree of (and increasing) coordination between systems. There are numerous separately operated transmission systems within FRCC, each of which covers a relatively small geographic area. SERC contains a number of vertically-integrated utilities with large geographic footprints. At the opposite extreme, MISO is the reliability coordinator for 35 separate control areas covering a large footprint, but has limited, albeit, expanding operational control of the transmission facilities of its members. In the WECC, the operation of large segments of the grid is consolidated in a few large entities including the California ISO and BPA.

Clarity of roles and responsibilities and effective execution are the key elements of ensuring reliability, not any specific organizational structure or degree of geographic fragmentation. Roles and responsibilities of each entity must be clearly articulated, agreed upon and documented.

## CECA FINDINGS

The CECA Forum reached several findings related to transmission operations and planning. First, it is clear that to ensure adequate investment in the nation's transmission infrastructure, the entity ultimately responsible for transmission planning must be identified and held accountable. It must have the authority to mandate investment if necessary. Similarly, with respect to ensuring reliable transmission operations, the entity responsible for monitoring and enforcing compliance with reliability standards must be given clear authority to do so.

The following findings provide a foundation and context for the recommendations in Chapter Six for action and policy guidance with respect to transmission planning, operations and investment:

### *Findings on Consumer Participation in the Planning Process*

It is clear that consumers benefit from the opportunity to provide timely, meaningful input into the transmission planning process. In the absence of a formal planning process with an explicit provision for public participation, the opportunity for such public participation may be limited. Whether the planning process is formal or informal, consumers must be given an effective role in which their views are taken into account and whereby they can actually influence the planning process. This will require that consumers or their representatives be provided with adequate information and that they have the capability to analyze and use that information. At the same time, the planning process should be structured such that the good of the whole is properly weighed against individual costs and interests. Provisions must be adopted to ensure that individual stake-

holders, who oppose new transmission enhancement projects that benefit the system and consumers as a whole, cannot be allowed to unduly delay or exercise veto power over particular projects.

### *Findings on Compliance with NERC Standards*

Consumers and the overall economy of the nation benefit when the power stays on. NERC has been instrumental in developing protocols for the safe and reliable planning and operation of the bulk electric power system. As the events of the August 2003 Blackout demonstrate, reliable operations depend on operators complying with reliability standards, maintaining a global view of the interconnected transmission system, and having the authority to take remedial actions when problems develop. There are a variety of organizational configurations of reliability coordinators and control area operators within and across organized markets, traditional vertically-integrated utility frameworks, and hybrids of the two. However, whatever their organizational form, the management of transmission system planning, operations and maintenance must comply with national, regional and local reliability standards.

### *Findings on Coordination among State Regulators*

Many issues related to transmission planning, such as siting, resource adequacy, and cost allocation, cut across state lines. Coordination and consensus among state regulators, through properly structured Regional State Committees or other entities, may facilitate the resolution of these issues, contribute to regulatory certainty, and foster investment.

### *Findings on Regulatory Certainty with Respect to Cost Recovery and Allocation*

Consumers overall will benefit from additional cost-effective transmission investment. Transmission investment will not take place when the rules for cost recovery and allocation are unclear, when provisions for cost recovery are uncertain or inadequate, or when the process for determining cost allocation is unduly contentious. Clearly articulated and durable regulatory policies for cost recovery, which provide assurances that investors will have a reasonable opportunity to recoup their investment, will generate support for such investment. Similarly, clear rules, such as default cost allocation mechanisms, will serve to increase regulatory certainty, facilitate the planning process, and foster investment.

### *Findings on Regulatory Oversight of Transmission Operations, Maintenance and Investment*

Violations of NERC operating protocols are punished through the threat of legal liability, peer pressure and other non-monetary sanctions largely implemented at the regional level. As formal regulation of transmission operations is introduced, more innovative “carrots and sticks” regulatory mechanisms should be developed to encourage utilities and other transmission providers to

improve transmission operations and maintenance practices and to efficiently and cost-effectively expand the transmission grid where warranted. Under any such regulatory framework, policies should be adopted which clearly specify the goals to be met, the performance metrics to measure their achievement, and the method for allocating benefits actually achieved between consumers and transmission owners.

### *Findings on Strategic and Coordinated Regional Transmission Planning to Assure Reliability*

The interconnected nature of the transmission grid as evidenced by the August 2003 Blackout requires coordination of transmission planning and operations across regions. Transmission investment often benefits consumers far from the facility's physical location. Hence, it is critical that different interconnected entities and regions coordinate planning. The planning processes of organized markets, large vertically-integrated utilities, and federal entities such as BPA and TVA, have broad regional implications. It may be possible for smaller entities, such as many municipal utilities, to coordinate or participate in the planning of projects with broad regional benefits without sacrificing autonomy over transmission investment with purely local benefits. A "National Power Survey," similar to those conducted in the past, would facilitate regional planning and the broad perspective required to meet overall consumer needs.

In addition, because of the substantial lead times required for transmission investment and because transmission investment has the potential to affect future generation investment, transmission planning should be forward-looking and strategic. Transmission planning should take into account the different types of resources that are likely to be available including remote resources such as mine-mouth coal, wind power and other alternative energy resources, new transmission facilities, load-center generation, nuclear power, distributed generation, demand response, energy efficiency, and new advanced transmission-related technologies that can make the operation of the electricity system more efficient and facilitate new electricity products and services for consumers. Likewise, transmission planning must also consider other major changes to the electricity system, such as generation additions and retirements, and the impacts of fuel price levels, volatility and fuel availability, which will affect transmission plans and operations.

### *Findings on Regional Transmission Planning for Economic Upgrades*

The regional transmission planning process should address economic, in addition to reliability, upgrades. The entity responsible for regional transmission planning should identify the need for an economic upgrade using clearly defined criteria, including a comparison of projected benefits and costs. As with the reliability planning process, the planning process to identify the need for economic upgrades should take into account the different types of resources that are likely to be built by others, such as load-center generation, remote generation, distributed generation, demand response, energy efficiency, and other transmission projects, including merchant transmission.

### *Findings on Cost Allocation for Economic Upgrades Undertaken by Regulated Utilities*

Rules and procedures for determining who should pay for economic upgrades (e.g., default cost-allocation mechanisms) are also needed to ensure that investors are given appropriate incentives to make such upgrades, and the reasonable opportunity to recover costs that are prudently incurred. Transmission investment to reduce congestion costs for consumers in one area may need to be made in another area where the benefit to local consumers may not be evident. In organized markets with a process intended to elicit market-based investment, that process should include provisions for ensuring regulated economic upgrades if necessary – i.e., upgrades where the benefits of such investment are clearly demonstrated and exceed their costs and meet other previously defined criteria – in the event that market mechanisms are not adequate to provide assurance of sufficient investment to alleviate congestion where it is cost-effective to do so.

### *Notes*

1 "Centrally organized markets" refer to those markets with an ISO or RTO responsible for transmission system operations as well as centrally dispatched spot energy markets.

2 The analysis did not examine the transmission planning and operations practices of one large organized market, namely California's, which is inside the WECC.

3 In what follows, we use the generic term "region" to refer to geographic areas that may or may not coincide with the boundaries of NERC regions. Appendix A is a compilation of the summaries of regional transmission planning and operations practices prepared by members of the CECA Forum for this report.

4 Hybrid markets include elements of both the traditional markets dominated by vertically-integrated utilities and the more fully restructured markets such as PJM. For example, in a hybrid market, an RTO might operate the transmission system and balancing and ancillary services markets, but utilities would still build generation and sign long term contracts to meet most of their native load.

5 As indicated earlier, discussions about transmission investment often distinguish between "economic" and "reliability" upgrades. "Economic" upgrades address transmission constraints that cause congestion leading to high generation costs but that do not jeopardize reliability. It is generally recognized that the line between economic and reliability upgrades is not necessarily clear. Nor is the line separating economic upgrades from entirely localized projects easy to locate.

6 Non-wires options are non-transmission options that in some circumstances can be assembled to relieve congestion and help to solve reliability problems, for example, generation (both base load and peaking) built close to load centers, distributed generation, energy efficiency and strategic demand response.

7 One example of this dynamic is the Cross Sound Cable between Connecticut and Long Island. See summary of this example in Appendix B.

8 These regional organizations of states regulators are the New England Conference of Public Utility Commissioners ("NECPUC") and the Mid-Atlantic Conference of Regulatory Utility Commissioners ("MACRUC").

9 Again, the Cross Sound Cable project may be an example where the one host state objected to operation of the cable where other states supported its operation. However, in this instance, on June 27, 2004 the two states settled their differences and the Cross Sound Cable was reactivated on July 2, 2004.

10 NERC, *Maintaining Reliability in a Competitive U.S. Electricity Industry: The Final Report of the Task Force on Electric System Reliability* (September 29, 1998) includes Appendix G titled: Issues of Federalism in Transmission System Reliability. The report states that the Task Force supports the establishment of Regional Regulatory Agencies ("RRAs") under certain specified conditions, stating, "Where RRAs are created by the states, their proceedings should *replace* otherwise applicable state and local reviews." (emphasis in the original)

11 MISO, "Organization of MISO States, BYLAWS," June 11, 2003.

12 FERC, Joint Petition for Declaratory Order to Form a New England Regional State Committee, (Docket EL04-112-000) June 25, 2004.

13 Southwest Power Pool, 106 FERC ¶ 61,110, 2004 (February 10 Order).

14 Membership fees can pose another barrier to participation. To facilitate consumer participation, many regional and national organizations such NERC and ISO-NE waive membership dues altogether or reduce them substantially for consumer representatives.

15 The Technical Advisory Committee ("TAC") aids in the design of the ERCOT transmission plan. The TAC is composed of two representatives of industrial consumers, one representative of small commercial consumers, one representative of large commercial consumers, and one representative of residential consumers. Each member is entitled to one vote.

16 Consumers have opportunities for input into the MISO planning process through the MISO committee process (development of the "MTEP"), particularly through the Planning Support Group which meets every other month, in which there are no assigned members and all meetings are open to the public.

17 Some areas outside of organized markets contain entities that plan, own, and operate transmission, but do not necessarily serve retail customers, such as Tennessee Valley Authority ("TVA") and Bonneville Power Authority ("BPA").

18 For example, see William H. Hogan, "Transmission Market Design," 2003 (http://ksghome.harvard.edu/~.whogan.cbg.Ksg/trans_mkt_design_040403.pdf).

19 In its "Standard Market Design" proposal, FERC described locational marginal pricing or LMP in the following way: "LMP is the method that is used for managing congestion in the regional markets run by both PJM and New York ISO…. Marginal pricing is the idea that the market price should be the cost of bringing the last unit to market (the one that balances supply and demand). LMP in electricity recognizes that the marginal price may differ at different locations and times. Differences result from transmission congestion which limits the transfer of electricity between the different locations. [fn] The marginal price of energy at a particular location and time – that is, the energy LMP – is the additional cost of procuring the last unit of energy supply that buyers and sellers at that location willingly agree on to meet the demand for energy. That is, it is the price that "clears the market" for energy. [fn: Under LMP, all suppliers selling at a location receive the market clearing price, including those who offer in their bids to sell for less. Similarly, all buyers purchasing at the location pay the market clearing price, including those who offer in their bids to purchase at a higher price….] LMP is a market-based method for congestion management. ….When there is no congestion anywhere on the system (when there is enough transmission capacity to get power from the cheapest available generators to all potential buyers) there will be only one energy price in the transmission system, the price bid by the last, or marginal, generator that provides energy or load that offers to reduce its demand. [fn] When there is congestion, the cheapest generators may be unable to reach all their potential buyers. Consequently, when there is congestion there may be many different energy prices across the transmission system. [fn]." FERC, Standard Market Design Notice of Proposed Rulemaking, Docket No. RM01-12-000, paragraphs 204-205.

20 One example of market-based approaches providing inadequate incentives to invest in economic upgrades has been the NYISO's experience with Transmission Congestion Contracts ("TCCs"), in which those specific parties that invest in such new upgrades get the benefit of the capacity additions through assignment of TCCs and any rights, benefits and obligations that flow from them.

21 For a more detailed discussion of this issue, see James Bushnell and Steven Stoft, "Electric Grid Investment under a Contract Network Regime," *Journal of Regulatory Economics,* Vol. 10, No.1, 1996.

22 There are also certain transmission investments – such as interconnections to serve new generators – that are generally allocated directly to the entity (i.e., the generator) for which they are made, though there are exceptions to this practice. In some cases, additional costs incurred for aesthetic reasons, e.g., to locate a transmission line underground in a scenic area, may be assigned to that locality rather than to transmission consumers more broadly.

23 A recent FERC order upholding this policy is the subject, however, of reconsideration requests from utilities and PUCs in the State of Maine, New Hampshire and other entities concerned about receiving a disproportionate share of rolled-in costs. (FERC, "Order on Complaint and the Proposed Amendments to the NEPOOL Tariff and the Restated NEPOOL Agreement," December 18, 2003, 105 FERC ¶ 61,300.)

24 U.S.-Canada Blackout Report, 2004.

25 Current industry reliability standards are found in the NERC Planning Standards and the NERC Operating Manual, with operating standards set forth in operating policies contained in the Operating Manual and Appendices. The operating policies include "standards" and "requirements," along with "guidelines" and "crite-

ria." For purposes of this report, the term "reliability standards" refers to the entirety of reliability-related policies now in the NERC Operating Manual and Planning Standards and those evolving through the formal standards development process.

26 Some regions, such as the NYISO, follow a more stringent "N-2" criterion.

27 In the New England ISO, even though the ISO is primarily responsible for generation dispatch and the operation of transmission facilities, there is also a set of "Satellites" which control sections of the New England bulk power system from separate control rooms but in response to instructions from the central ISO control room. At the inception of the New England market, it was deemed too difficult to consolidate the operation of all transmission and generation in the ISO's footprint in a single control room. The Satellites were intended to be temporary, with all real-time operations eventually consolidated.

28 Two control areas in SPP use MISO as their reliability coordinator.

29 U.S.-Canada Blackout Report, 2004.

30 In addition, some regions (such as SERC, WECC and the Northeast Power Coordination Council ("NPCC") — which includes the NYISO and ISO-NE) follow reliability standards even more stringent than NERC's.

31 The WECC system of financial sanctions is known as the Reliability Management System (RMS).

32 SERC members have also signed onto the Regional Compliance and Enforcement Program ("RCEP") whereby they have agreed to be penalized for non-compliance with NERC standards. For certain violations, these penalties are monetary.

33 U.S.-Canada Blackout Report, 2004.

34 SAIDI is a standardized statistic used to measure the average length or duration of outages, usually due to problems on the distribution system. Similarly, SAIFI is used to measure the average frequency of outages.

# Chapter 5

# Potential Implications of Change

## The Impacts of Changing Demands on the Transmission System

Chapter Three outlined the CECA Forum's consideration of the implications of the continuation of current trends in transmission investment for consumers over the 10-year time period considered in this study. The analysis found that if needed and cost-effective investment continues to be discouraged by the current regulatory and financial environment, the result would lead to increased stresses on the transmission system, with reduced service quality and greater risk of degradation of reliability – an outcome adverse to consumers. This Chapter discusses the implications for consumers of the changing demands on the transmission system that could result from changes in underlying macro-economic factors (e.g., population and economic growth), electric load growth, generation capacity additions and retirements, fuel prices and availability, and modification of various energy policies.

Change is inevitable, and some degree of change is assumed in the continuation of current trends. However, particular, underlying factors may change in unexpected ways, and the direction and magnitude of these changes are difficult to predict. Certain changes will increase demands on the transmission system, others will likely decrease demands on it, and others may do both depending on location, size, and pattern of impacts. To meet consumer needs over time the transmission system must be robust and flexible enough to meet reliability standards under a variety of circumstances and handle the consequences of change in a manner that ensures that benefits to consumers will exceed costs.

To examine the implications of changing demands on the transmission system, the CECA Forum examined the impacts of changes in a variety of factors affecting the utilization of the transmission grid, including:

- Fuel prices and availability;
- Generation additions and retirements;
- Increased consumer demand due to greater than expected economic growth and new uses of electricity;
- Reductions in consumer demand due to increased energy efficiency and wider deployment of distributed generation; and
- Public policy changes.

*To meet consumer needs over time the transmission system must be robust and flexible enough to meet reliability standards under a variety of circumstances and handle the consequences of change in a manner that ensures that benefits to consumers will exceed costs.*

While the impacts of such changes are difficult to predict, the CECA Forum undertook an analysis designed to inform decisions. The process involved identifying and describing the potential for changes in the electricity system that will affect demands on the transmission system. The scenarios developed by the CECA Forum are not intended to paint a definitive picture or even a series of pictures of the future. The scenarios are valuable to help planners and policymakers envision the kinds of enhancements necessary to enable the

transmission system to respond to a broad spectrum of changes. Unless the transmission system is robust and flexible enough to operate reliably under a variety of conditions, it will not be possible to meet consumers' needs economically or reliably.

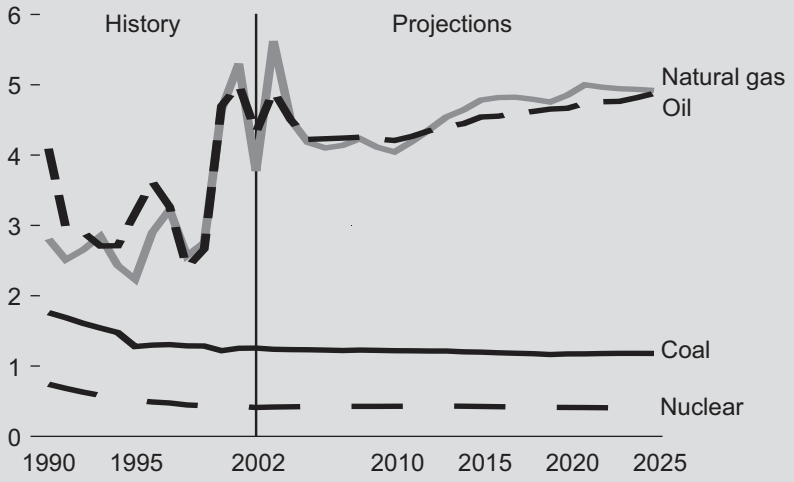
## *Factors Affecting the Use of Transmission and their Implications for Consumers in the Future*

### *Fuel Prices and Availability*

The CECA Forum's analysis is based on data and forecasts from the U.S. Energy Information Agency's 2004 Annual Energy Outlook.[1] At the time of EIA's forecasts in early 2004, natural gas prices were expected to remain high in the short term and then stabilize and increase at approximately 1.2 percent per year over the next 10 years. Clearly, this forecast has been greatly exceeded by reality. Rather than stabilizing between $4.00 and $5.00 per mmBtu, as illustrated in Figure 13, natural gas prices have been extremely volatile over the course of 2004, with the lowest prices around $4.50, the mid-point of the EIA forecast, and reaching over $8.00 at one point during the year. Prices averaged almost $6.00 per mmBtu for 2004 overall. It is not clear whether high prices for natural gas will continue in the future, or decline to levels projected in early 2004. Figure 13 also shows that natural gas prices have been extremely volatile over the last few years. To the extent that this level of volatility continues, gas prices can be expected to fluctuate and it will be difficult to predict future trends.

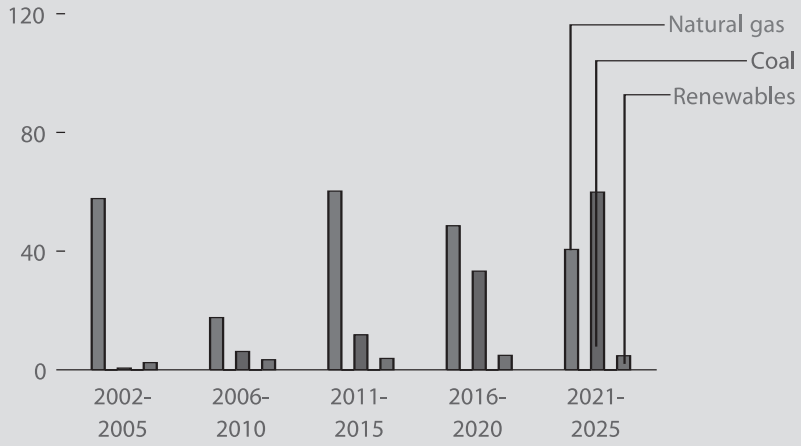
EIA expects coal prices to decrease very slightly (-0.3 percent per year) in real terms over the next 10 years. While there are no new nuclear plant orders, the analysis assumed license extensions and repowering of existing nuclear plants.[2] These trends can be seen in Figure 13.

**Figure 13**
**Fuel Prices to Electricity Generators**
**(1990-2025, 2002 dollars per million Btu)**




Source: EIA, *Annual Energy Outlook 2004,* Figure 73, page 83.

**Figure 14**
**Electricity Generation Capacity Additions by Fuel Type, Including Combined Heat and Power (2005-2025, GWs)**




Source: EIA, *Annual Energy Outlook,* Figure 71, page 82.

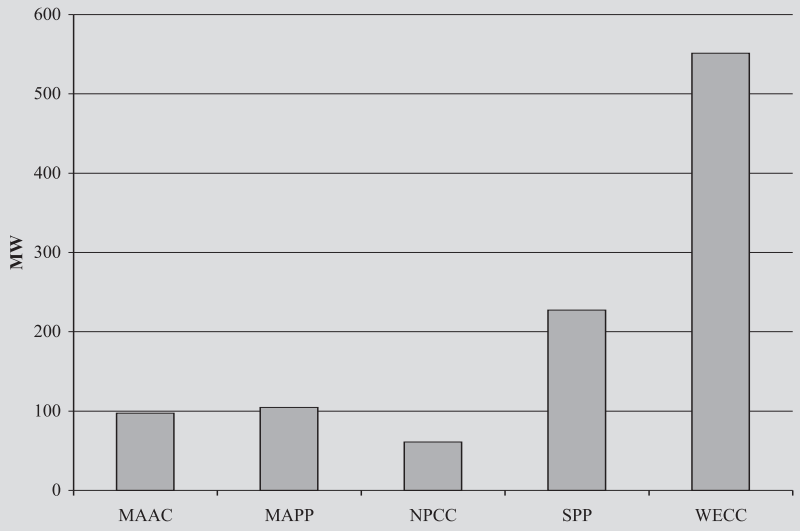
Oil prices were assumed to remain relatively high compared to the 1990s, as shown in Figure 13, but the EIA did not anticipate the level of increase seen over the summer and fall of 2004. Oil prices in the fall of 2004 steadily exceeded $40/barrel and reached more than $50/barrel – well above the level of $27.25/barrel in 2003 predicted to decline to $23.30 in 2005[3] according to EIA's forecast of oil prices. Future trends for oil prices are unclear, given recent price patterns. Consistent with the fuel price projections illustrated in Figure 13, most generating capacity additions over the next 10 years are expected to be gas-fired, with a small number of orders filled for traditional coal-fired plants in some regions. This is shown in Figure 14. While wind power is assumed to grow at roughly 25 percent annually, no more than 10 percent of capacity is expected to come from renewable energy projects. Whether fuel choices for capacity additions will change based on the significant increases in natural gas and oil prices during 2004 remains to be seen.

If natural gas prices remain at high levels or continue to exhibit the volatility shown over the last few years, an immediate effect on the electricity system would be that changes would occur in the dispatch of generation; with resulting changes in power flows on the transmission system as natural gas fired units become more expensive to operate. High levels of natural gas and oil prices could also affect generation dispatch and mix.

In addition to changes in dispatch, which affect the utilization of the transmission grid, increases in natural gas and oil prices can also lead to a shift in the generation mix toward coal, more closely resembling the out years (2021-2025) of the EIA generation mix forecast. The extent to which new coal-fired generation will replace expected gas-fired generation will be affected by environmental requirements for emissions reductions that may necessitate expensive capital investment for clean coal technologies.

Extremely high natural gas prices could also lead to increased use of renewable energy, particularly wind. Depending on the location of these plants, the shift from natural gas to coal and wind could lead to increased demand on the transmission

**Figure 15**
**Planned Wind Capacity Additions**
**(2003-2007)**




Source: 2002 EIA Form 860 data, excludes cancelled or indefinitely postponed projects.

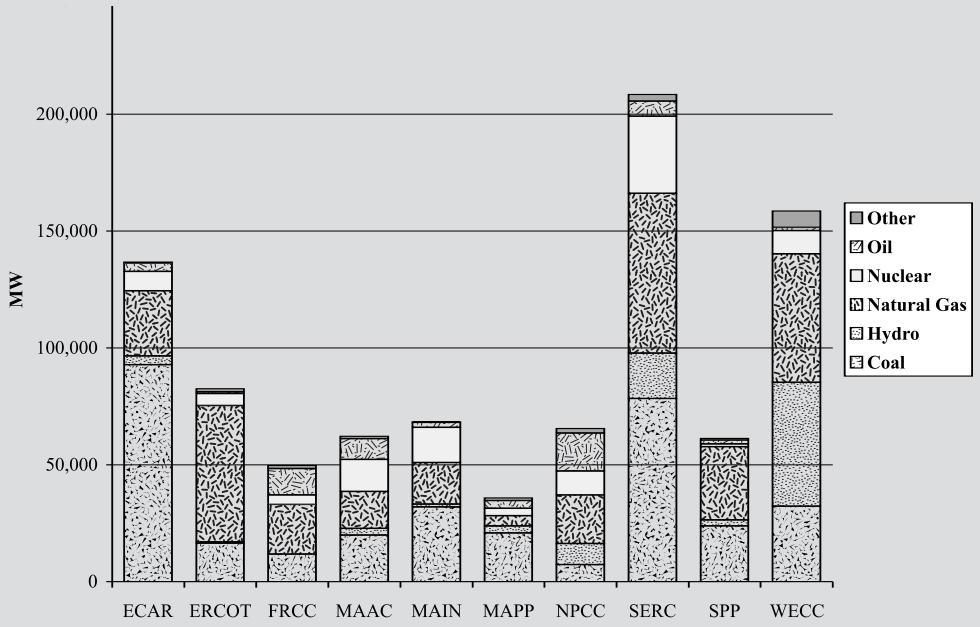
system. As Figure 15 illustrates, planned wind resource additions are significantly higher in the West than in other regions.

A sense of the size of the change in transmission requirements due to a shift from natural gas to coal and wind is shown in one report prepared for the Western Governors' Association. According to that study, transmission requirements resulting from the greater use of natural gas forecast at prices lower than is has been experienced in the past year were expected to cost about $2.1 billion in the West.[4] Greater use of coal, wind, geothermal and hydropower facilities for electricity generation that might occur as a result of high natural gas prices will require much more transmission than for gas-fired facilities because the gas-fired power plants tend to be located close to load centers. New coal plants, particularly mine mouth coal, and wind generators are generally located remotely, requiring additional investment in transmission and/or increasing constraints on the existing grid. The cost of this transmission would be significantly more: perhaps as high as $8 billion - $12 billion.[5]

In addition, coal and wind generation are likely to be developed where these resources are abundant – i.e., the South and upper Midwest – increasing regional differences in generation capacity mix and the potential for transmission-related barriers as well as congestion on transmission interconnections between these regions and others where significant coal and wind development is less likely. Figure 16 shows generation capacity by fuel type and NERC region. Coal dominates in the Midwest and represents a significant portion of generation in the South. Figure 17 demonstrates that future additions of coal are likely to occur in the Midwest where it is the dominant fuel source.

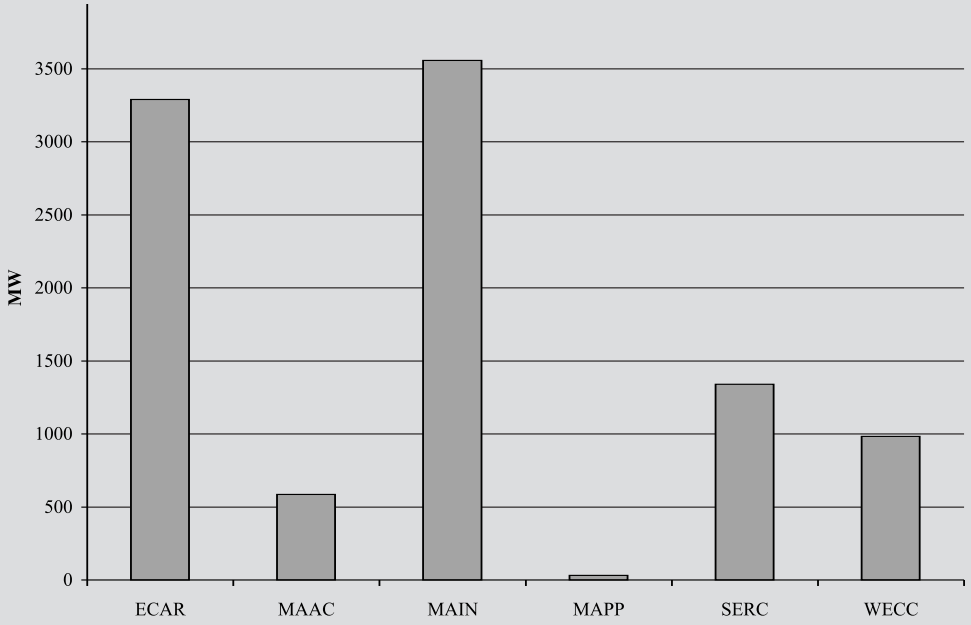
Natural gas price increases will also lead to higher electricity prices, particularly in those regions with spot markets that already rely heavily on natural gas-fired capacity to meet peak demand. Fuel availability (and concerns about it and its

**Figure 16**
**Operating Capacity by Fuel and NERC Region**
**(2002)**




Source: 2002 EIA Form 860 data.

**Figure 17**
**Planned Coal Capacity Additions**
**(2003-2007)**



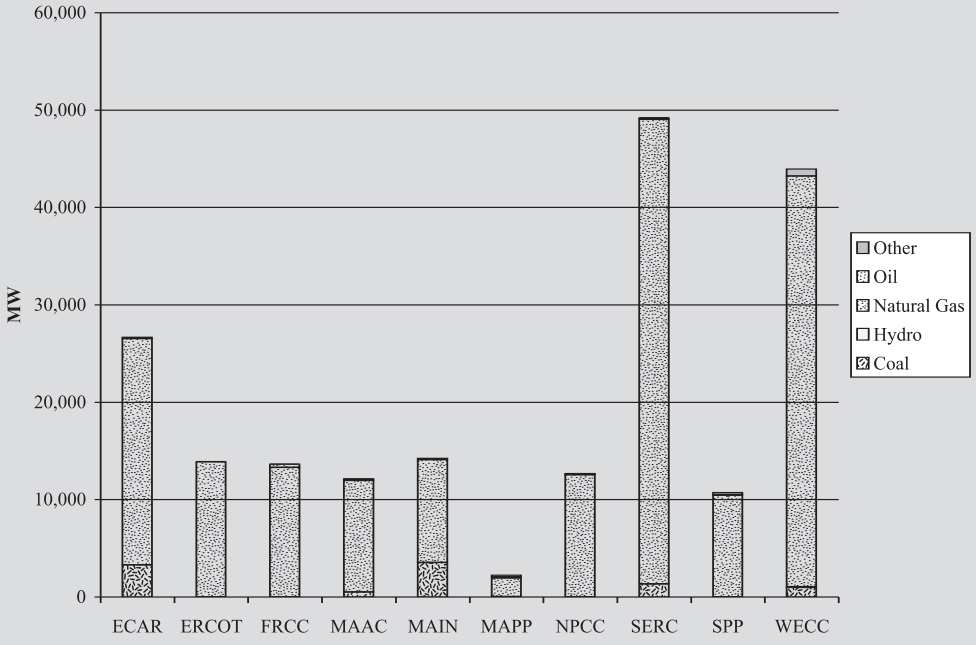

Source: 2002 EIA Form 860 data, excludes cancelled or indefinitely postponed projects.

price impacts) will also affect the mix of future generation. Uncertainties exist concerning the adequacy of gas supplies for generation in the next few years. These uncertainties can have important effects on the transmission system, grid operations, and the price, reliability and environmental impacts of electricity provided to consumers. Based on prices seen and projected in early 2004, natural gas was expected to be the predominant fuel for new generation to be added during the study period. As Figure 18 indicates natural gas-fired capacity was projected to increase in all NERC regions. If this natural gas-fired capacity is added, the consequences of any disruption in natural gas supplies or of price spikes such as have occurred in the last few years will increase in terms of reduced reliability and increased costs to consumers.[6] Recent experience in New England also demonstrates the vulnerability of the system to fuel shortages, whether due to short term supply disruptions or long term capacity issues.[7]

The case can be made that higher electricity prices will increase incentives for energy efficiency and distributed generation which if substantial, will lead to reduced demand on the transmission system. Clearly, to the extent that fuel price increases lead to higher electricity prices, the economics of distributed generation for consumers will improve. However, the distributed generation technologies (e.g., micro-turbines, fuel cells) that are likely to predominate during the 10-year timeframe of the CECA study rely on natural gas as a fuel. Sustained high gas prices could affect the rate of adoption of these technologies. Projections call for significant increases in the penetration of these technologies over current levels as illustrated in Figure 19.

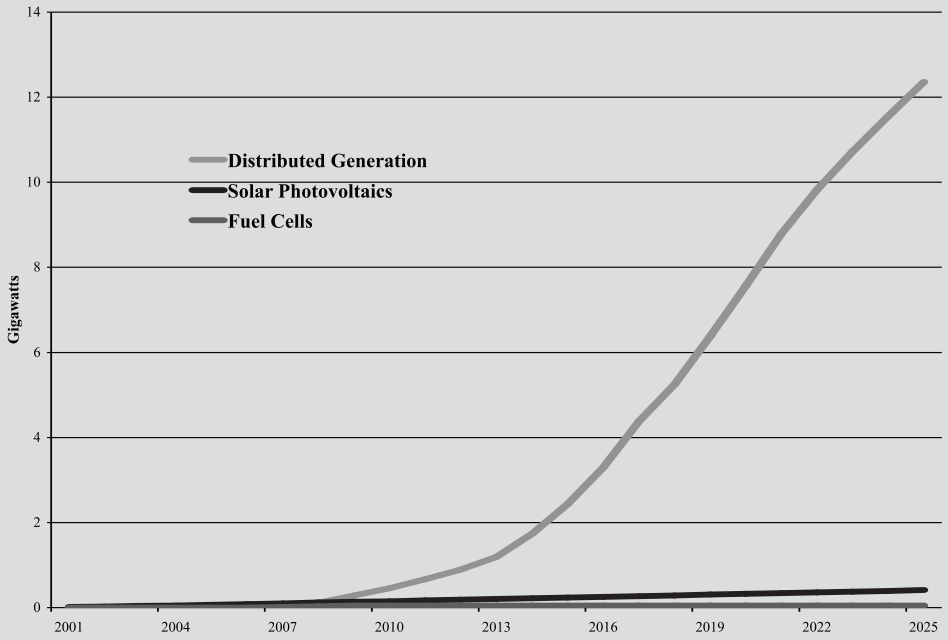
However, these distributed generation technologies are still expected to remain a small percentage of overall generating capacity, as illustrated in Figure 20. It is not clear yet whether renewable distributed generation technologies other than wind power will achieve the unit-cost reductions needed to make them cost-effective even with high natural gas prices. Figure 21 shows that

**Figure 18**
**Proposed Additions by Fuel and NERC Region**
**(2003-2007)**




Source: 2002 EIA Form 860, excludes cancelled or indefinitely postponed projects.

**Figure 19**
**Distributed Generation, Fuel Cells and Photovoltaics**
**Generating Capacity Projections**




Source: EIA, *Annual Energy Outlook 2004* projections, at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html

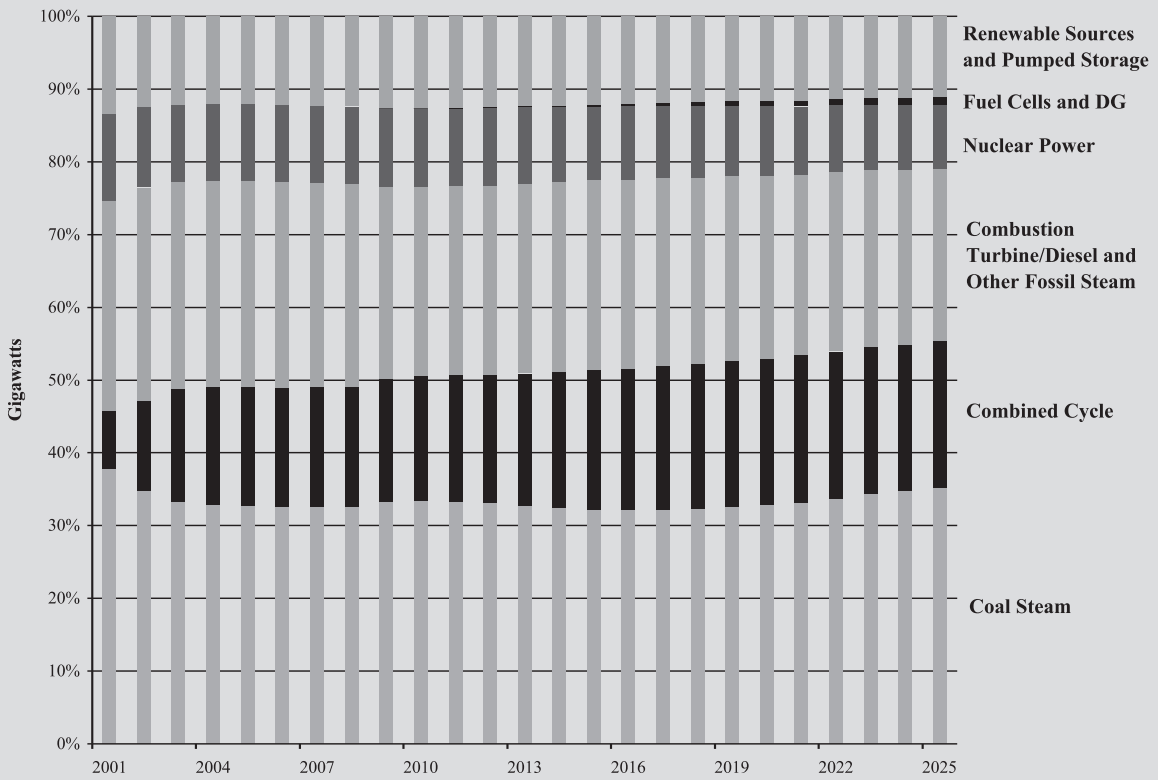
wind capacity levels and growth are expected to greatly exceed other renewable technologies. Therefore, while certain distributed generation projects may increase reliability and reduce the need for additional transmission or other local generation – assuming such distributed generation resources are located in congested areas and provide additional direct economic benefits to the consumers who install it – it would serve to complement rather than substitute for the benefits that transmission investment may offer to consumers.

For example, electricity prices may continue to be higher in a local area with the addition of distributed generation instead of transmission because lack of adequate transmission capacity will still inhibit lower cost power located outside an area from reaching consumers within the area. Central station combined cycle units are more efficient than distributed generation technologies that burn fuel and are likely to remain so through the CECA Forum's study period. Also, the air emissions rates of combined cycle plants are lower. These factors need to be taken into account in weighing any choice between a distributed generation investment and a transmission investment.[8] In some cases, the distributed generation option will be less costly than transmission, while in others the transmission investment may offer more benefits to consumers.

While advanced renewable distributed generation technologies such as photovoltaics ("PV") and fuels cells are not expected to become economic over the next 10 years considered by the CECA study, they could become attractive investment opportunities if technical breakthroughs occur that reduce their costs. In addition, if high natural gas and oil prices continue or increase, distributed generation deployment could accelerate. Under such conditions, the cost of renewable energy investment would be less than the cost of implementing fossil-fuel based technologies, and would bring with it concomitant environmental benefits for consumers.

In any event, even if the penetration of distributed generation increases significantly, it is still unlikely that its location and size will significantly

**Figure 20**
**Electricity Generation Capacity Projections**




Source: EIA, *Annual Energy Outlook 2004* projections, at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html

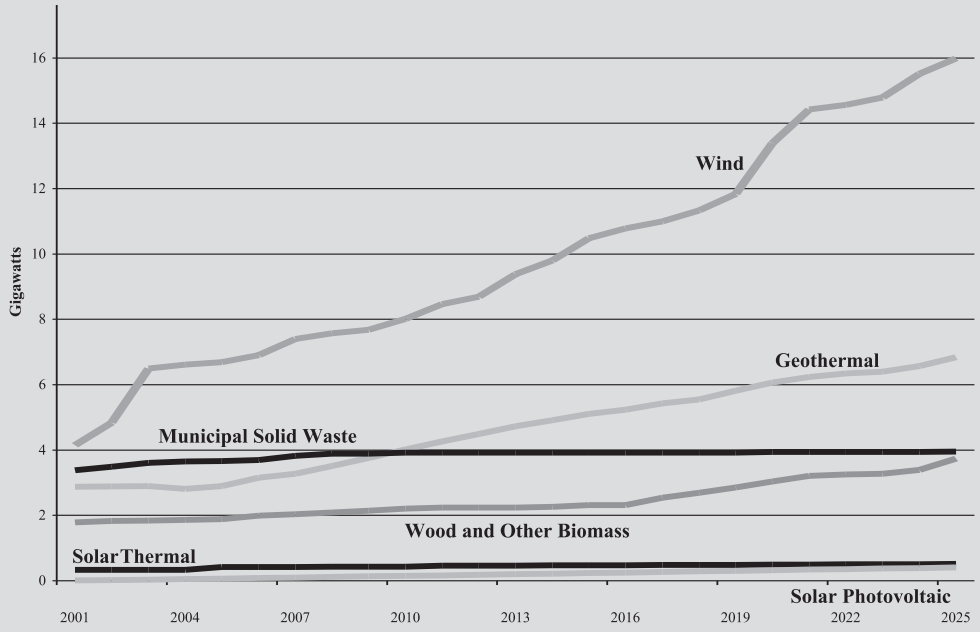
reduce demand for transmission service. One EIA projection estimates that distributed generation interconnected to the utility system will increase from 0.9 gigawatts in 2005 to 5.1 gigawatts in 2010 and 19.1 gigawatts in 2020. Even at this rate of growth, distributed generation in 2020, which is beyond the CECA study period, will still represent only about five percent of total generating capacity additions (354.5 gigawatts) for all technologies. For distributed generation in buildings, EIA projects significantly greater growth. Natural gas-fired distributed generation is expected to grow from about 4 billion kWh in 2000 to almost 22 billion kWh in 2020. Distributed generation in buildings from all fuel sources is projected to grow from 8 billion kWh in 2000 to over 27 billion kWh in 2020, with fuel cells and micro-turbines providing the bulk of that growth. Photovoltaics are expected to increase their share of the distributed generation market gradually as their costs are reduced.[9]

Recent, higher-than-expected natural gas and oil prices resulted in renewed calls for additional nuclear power capacity. Concerns about air emissions and global warming have similarly created renewed interest in nuclear energy. The relicensing of nuclear plants will expand and extend the operation of some of the existing fleet of nuclear units.

### *Generation Additions and Retirements*

If current trends continue, there will be a slowing of generation capacity additions over the next 10 years compared to the late 1990s. Only 88 gigawatts of new generation capacity (57 gigawatts of which are already in development) are projected to be needed to meet load growth between 2002 and 2010 – equivalent to approximately 11 gigawatts of generation capacity annually. At the same time, 62 gigawatts of generation capacity, almost all fossil fuel-fired, are expected to retire between 2002 and 2025 (see Figure 22).

**Figure 21**
**Renewable Energy Capacity Projections**



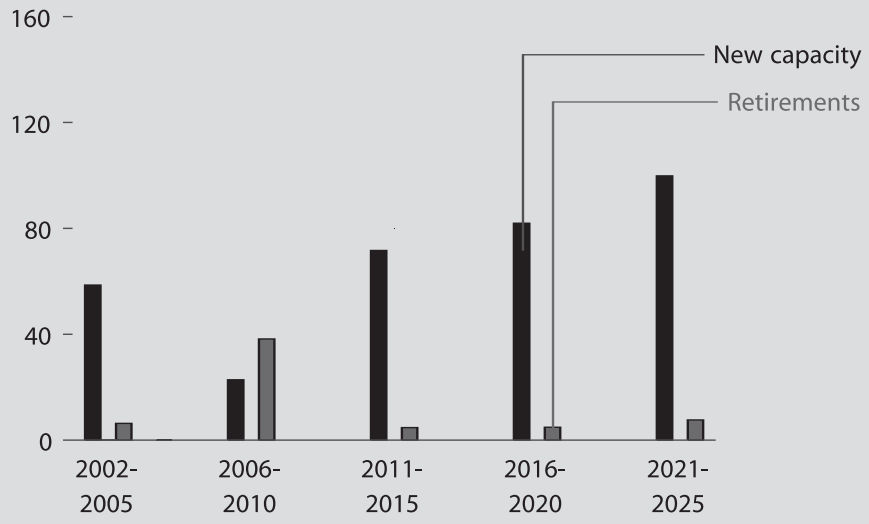

Source: EIA, *Annual Energy Outlook 2004* projections, at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html

This includes 35 gigawatts of existing oil- and natural gas-fired steam plants, 15 gigawatts of combustion turbines and 10 gigawatts of coal-fired plants.[10] From 2002 to 2005, generation additions will exceed retirements; from 2006-2010 retirements of older inefficient power plants (made possible in part because of the earlier additions) are forecasted to greatly exceed generation additions, but sufficient time exists for new generation to be proposed and constructed within this period.

Generation retirements and additions that differ from expectations, in terms of magnitude and locations, will affect the transmission system. Additional generation retirements could be driven by stricter environmental regulations that require capital investment that makes older existing units uncompetitive, perhaps earlier than expected, or fuel price increases that similarly increase costs for older oil- and natural-gas fired plants. Should oil prices remain high, older, inefficient oil-fired units are more likely to be retired sooner and in greater numbers than current trends would indicate. Similarly, older coal plants facing significant costs for compliance with new environmental regulations may be retired. Such retirements can increase congestion on the transmission system especially where these older units are located in load pockets or areas that already face transmission constraints. If these older units are needed to maintain reliability because transmission is not adequate to deliver power from outside the area and new generation options have not materialized to replace them (perhaps in part because transmission is not adequate to deliver their power outside the region), their owners will need to be compensated for their costs of operation if those plants are to remain available for operation – with the effect of increasing electricity prices to consumers.[11]

Not only do retirements have the potential to influence generation costs, they may also affect fuel diversity. Many older generating units have the capability to burn either natural gas or fuel oil. As these units retire, their contribution to fuel diversity will be lost. Although many of the new gas-fired units also have dual fuel capability, there are often environmental requirements that limit the amount of time that they can burn fuels other than natural gas. The diminution of relatively "flexible" generation with dual-fuel capabilities can increase the potential for transmission

**Figure 22**
**New Generating Capacity and Retirements**
**(2002-2025, GW)**




Source: EIA *Annual Energy Outlook 2004,* Figure 70, p. 81.

constraints to occur when gas availability is limited. The early or unexpected retirement of older coal plants can have similar impacts on the transmission system. Again, where these plants are located close to load centers in constrained areas, their retirement can increase congestion costs and/or threaten reliability.

Retirement of significant generation could also affect transfers of power between regions. For example, older steam plants in excess of 15,000 MW in California could retire in the next decade. These plants are generally located in load centers and because of environmental restrictions and other difficulties of siting new generation in developed areas, may not be replaced. This could significantly increase the need for both intra-state transmission in California and inter-state transmission into California.[12] Where these plants are not being replaced with generation in the same or nearby locations, investments in transmission may be needed to maintain reliability, or minimize higher electricity prices associated with increases in congestion.[13]

The possibility of significant additions of wind capacity in the relatively near term – five to 10 years – raises its own challenges for the transmission system. There are two main implications of wind power development for transmission. First, wind power tends to be sited in remote locations and hence requires new transmission to move the wind power to customer loads. Second, and more subtle, is the implication of the remoteness of wind generation for transmission investment: building transmission lines to connect major new wind resources frequently involves anticipation of generation that is not yet even planned. While this problem is not unique to wind generation in that it applies to all new generation, the intermittent nature of wind generation output makes the forecasting process as well as the inherent economics of such transmission enhancements more challenging. Given this uncertainty, it is difficult to appropriately size – or perhaps even to justify – the transmission investment.

Transmission pricing can be complicated. If the first projects in a new wind resource area are

asked to bear a disproportionate share of the costs of transmission investment, then wind generation investment is likely to be stunted. Also, because wind is an intermittent resource, building transmission capacity to meet peak output can be costly and difficult to support with revenues from plants with low capacity factors. Consequently, in several major wind resource areas, such as West Texas, where wind project development might have favorable economics, actual investment in wind projects can be hampered by the combined economics of its development and delivery costs.

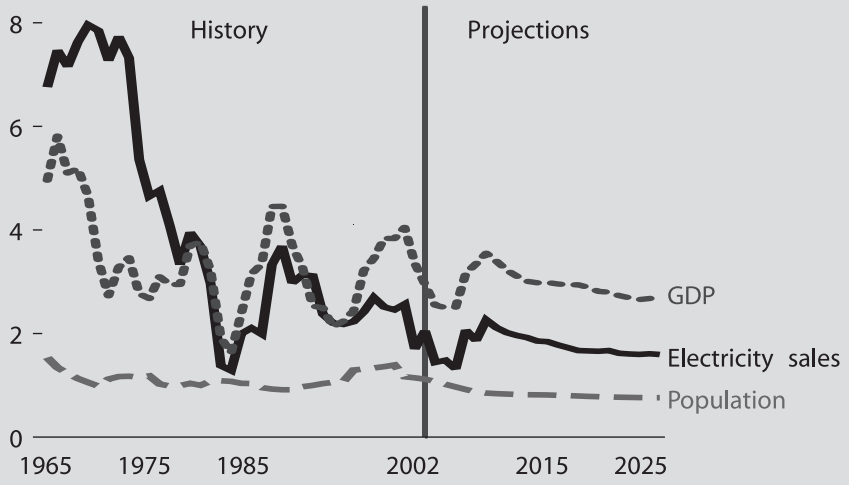
### *Changes in Consumer Demand*

If current trends continue, consumer demand for electricity is expected to increase at a rate of 1.8 percent annually over the study period, with greater growth in parts of the South, parts of the West, and Texas, and slower than average growth in the Northeast and Mid-Atlantic regions. According to EIA (see Figure 23), this average growth rate is expected to follow trends over the last 10 to 20 years and be slower than expected GDP growth rates.[14]

Consumer demand could increase even faster under some circumstances and in some regions. The most likely driver of increased electricity demand would be economic growth at a rate higher than expected. While electricity demand is projected to grow at a slower rate than the GDP, it does track economic growth. Increased economic growth is more likely to be seen in some regions – e.g., the South and Southwest – than in others such as the Northeast and Mid-Atlantic. These patterns of electricity growth could increase inter-regional constraints and transmission congestion adding to the stress on the transmission system.

Consumer demand for increased power quality and reliability could also grow as more and more sensitive technologies are used in a variety of industries, commercial applications and even at the residential level. This growth in demand for power quality might be more widely dispersed than demand growth driven by the overall economy. The impact on the transmission system will depend on how this demand for power quality is met. Consumers may seek higher quality and more reliable power from their utilities or

**Figure 23**
**GDP and Electricity Demand**
**(1965-2025)**




Source: EIA, *Annual Energy Outlook 2004,* Figure 67, p. 80.

may resort to investing in their own equipment to upgrade power quality (e.g., some forms of distributed generation or energy storage technologies, etc.). To the extent that consumers demand higher quality power from their utilities, additional investments at both the distribution and transmission levels are likely to be needed to meet this demand, and could be significant.[15]

Alternatively, consumer load could grow more slowly than expected. If electricity prices rise, one could expect energy efficiency investments to exceed status quo assumptions. Load management technologies could be implemented more widely in response to utility and RTO/ISO demand response programs, if the cost of these technologies decreases significantly, or if sophisticated new communications devices are added to the transmission and distribution systems to enhance their capabilities.[16] Further, if the cost of distributed generation technologies comes down and they become more readily available, there will be increased pressure to address institutional barriers to distributed generation development, such as interconnection requirements and utility standby and back up rates (i.e., rates charged to consumers who install distributed generation for power they purchase from the distribution utility for supplemental or standby use when their distributed generation plant may not be operating and able to meet all their needs).

### *Policy Changes*

The current regulatory and policy context for transmission is characterized by uncertainty in a number of areas – siting, jurisdiction, wholesale market policy, industry organization, cost recovery and allocation, environmental regulation, and retail electricity policy. These conditions discourage transmission investment in some areas. These policies also affect investment in and development of a variety of electricity and energy resources whose deployment would have impacts on the transmission system. Clarification of these policy uncertainties, and in some cases adoption of policy reforms, could remove disincentives to investment in transmission and resources that would benefit consumers moving forward. The discussion that follows highlights key policy areas in which changes from the status quo could lead to such enhancements.

### *National Energy Legislation*

Comprehensive national energy legislation that includes an electricity title is uncertain at the time of publication of this report. The 108th Congress made strides toward passing a comprehensive energy bill which dealt with many issues addressed by the CECA Forum. Nonetheless, the legislation failed because of controversies other than the electricity title. Some contend that national legislation that includes federal backstop authority for transmission siting could facilitate transmission investment, reducing transmission development costs, lowering congestion costs and improving reliability, while others argue that siting authority appropriately belongs under state jurisdiction, as states are better suited to address the needs and concerns of local consumers who are most likely to be affected by siting issues.

National energy legislation could also reduce regulatory uncertainty by clarifying the role of FERC with respect to such activities as its authority (or lack thereof) to require ISOs/RTOs and the scope of its jurisdiction and role with respect to transmission planning and siting. While there are differing views with respect to what FERC's role in these areas should be, there is general agreement that a reduction in uncertainty would remove a barrier to transmission investment that could benefit consumers. The benefits would vary in regions with congested areas and locations where transmission investment has been difficult. Federal legislation with a national resource portfolio standards requirement would lead to the development of more renewable energy, which depending on its type and location – i.e., intermittent or dispatchable, remote or close to load centers – would have varying effects on the transmission system as has been discussed.

National energy legislation that mandates compliance with reliability standards and establishes the authority of FERC to enforce those reliability standards could lead to additional investment in

transmission enhancements. However, in spite of apparent universal support for this particular provision of a national energy bill, the adoption of national reliability standards failed in the 108th Congress because it was part of the failed comprehensive energy bill. In the absence of such legislation, NERC and FERC are expected to continue increasing pressure on companies to comply with voluntary standards.

### *Transmission and Wholesale Market Policy and Jurisdiction*

There continues to be uncertainty with respect to transmission policy jurisdiction. Tensions across the states and regions regarding what model of industry organization and regulation affords the best guardianship of consumers' interests in transmission remain high. In recent years, FERC has promoted a single Standard Market Design ("SMD" or "wholesale market platform") for transmission and central market organization functions. But more recently, in recognition of regional differences, FERC has backed off from pushing this SMD beyond those regions where it has already been adopted. FERC's wholesale market platform appears to be moving forward incrementally particularly in multi-state regions where ISOs/RTOs operate, including the large footprints covered by the Midwest ISO, PJM and the New York and New England ISOs.

However, if FERC establishes or clarifies a cost recovery policy for transmission or if federal legislation lays out a framework for electricity markets and/or clarifies the respective roles of federal and state regulators, barriers to investment in transmission and infrastructure could be removed or reduced and the stresses on the transmission system that are expected to continue and grow under current conditions could be alleviated.

### *Regulatory Treatment of Cost Recovery and Allocation*

The analysis of current trends in transmission assumes that cost recovery for transmission investment needed to ensure reliability will be allowed and that a certain level of reliability investment will therefore take place. If jurisdictional issues are resolved and federal and state regulators set forth clear policies for recovery of cost-effective transmission investments for economic upgrades, then these investments could proceed over the next 10 years of the CECA Forum's study period as well. Clear cost allocation and recovery policies for both reliability and economic upgrades would facilitate investment in transmission enhancements (including operations and maintenance) required to support critical infrastructure needs, improve service to consumers, maintain or increase reliability, and minimize costs.

### *Other Regulatory Policies*

A number of other regulatory and utility policies not directly related to transmission also affect utilization of the system. For example, policies regarding interconnection of distributed generation and standby and backup rates can facilitate or discourage consumer interest in distributed generation and in turn affect demands on the transmission system. The implementation of properly designed interconnection, standby and backup rates can be both compensatory to utilities and supportive of cost-effective distributed generation. As discussed earlier, distributed generation may reduce demands on the transmission system, particularly in congested areas.[17]

With respect to environmental policy and regulation, the CECA Forum's analysis assumed no changes to existing environmental requirements during the CECA study period. If the EPA's proposed Clean Air Interstate Rule is adopted or if three-pollutant legislation proposed in Congress is enacted and implemented, coal could lose its cost advantage over natural gas, at least in certain coal plants – depending on the emissions standards set and the deadlines for meeting them. If $CO_2$ emissions restrictions legislation were passed and implemented, it too could have a significant effect on the types of new generation added to the system. For example high environmental compliance costs for fossil fuels, combined with higher prices for these fuels, could

significantly improve the cost-competitiveness of renewable energy. The timing of the impacts would depend on the schedule set for $CO_2$ reductions.

In subtle ways, even the design of environmental regulations can affect pressures on transmission systems by changing the relative cost of power produced at different power plants in different locations relative to loads. For example, an environmental choice about whether to regulate air emissions on a Btu-input basis versus a MWH-output basis affects the variable costs, and therefore the dispatch, of certain power plants. Whether trading is allowed affects how emissions requirements are met; higher-emitting resources could continue to operate under a trading scheme in which emissions credits are bought from other plants where emissions reductions are less costly. If compliance with environmental regulations requires or hastens the closure of large coal plants, interregional power transfers will be affected and this could potentially increase congestion and/or reduce reliability. Changes in environmental regulations with respect to disposal of hazardous and other waste products (e.g., municipal solid waste, wood) could also affect the future generation mix, but the effect is likely to be small.

### *Tax Credits and Subsidies*

Tax credits and subsidies will affect investment in different types of generation, which in turn will affect demand on the transmission system. For example, tax credits for wind had expired at the end of 2003, making investment in wind generation less attractive. However, in the fall of 2004 renewable production tax credits were reinstated through 2005,[18] and are expected to cause the level of wind development to increase once again. An increase in wind generation will affect the transmission system, as previously discussed. Remotely located wind installations may increase the need for transmission to connect them to load centers.

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The foregoing discussion describes a number of factors – fuel prices and availability, generation additions and retirements, consumer demand and public and utility policy – affecting demand for transmission. This Chapter points out how these factors can interact with one another and how changes in these various factors can affect the transmission system. Some changes will lead to increased demand for transmission while others will lead to reduced demand. In either case, the transmission system must be robust enough to respond to these changes.

### ***Findings on High Electricity Demand Implications***

A high electricity demand growth scenario could occur from a combination of such factors as: economic rebound above expected levels; unexpected and rapid policy clarification that assures appropriate investment recovery of transmission enhancements and lowers the costs of long-distance transmission; or lower than expected natural gas prices which would enable many of the newer gas plants to be dispatched with greater frequency if gas prices do not stay high. The combined effect of these impacts would be felt in the regions of the country that have a large amount of manufacturing and are growing – i.e., the South and the Southwest. From a transmission perspective, a high electricity demand growth scenario would increase pressure on demand for transmission ser-

vice into and within those regions where growth occurs. Increased demand could threaten reliability and increase costs to consumers if required or economic transmission system enhancements are not undertaken in the near term.

### *Findings on Low Electricity Demand Implications*

Conversely, lower than expected electricity demand could occur, for example, from a combination of such factors as very high natural gas and oil prices, lower than expected economic growth (that might result in part from high fuel prices), and higher electricity prices due to high fuel prices, particularly in the Northeast. The combined effect of these impacts might be increased power flows from coal areas to gas areas (e.g., from the Midwest to the Northeast and from the Rocky Mountains to California and Arizona) and congestion in areas of the Northeast (within and between regions). Therefore, while slow demand growth would most likely relieve demand for transmission, the factors that led to slow demand growth might have countervailing effects. If transmission investment is not sufficient to enable the grid to handle the potential consequences of these changing power flows, consumers will face the risk of reduced reliability and higher costs.

Slower demand on the electric grid could result from other trends, as well. The introduction of new integration technologies for utilization and recognition of demand response could also affect the *shape* of power loads. There could be less on-peak demand for a given amount of economic growth. This could occur, for example, if homes in the fast-growing Sunbelt where demand is driven by air conditioning were equipped not only with efficient air conditioners, but with smart thermostats that raised the temperature of the house a few degrees when conditions warrant, or when the homeowner specified. These new approaches could allow a distribution network to be built with far lower, and flatter, demand profiles than the current typical American home is designed for. Italy, for example, is installing 30 million interval meters in all homes and driving towards per-household demand not-to-exceed 2kW. Although that may be an aggressive goal for the typically more energy-intensive American household – especially within the time frames analyzed in this CECA Forum – the right combinations of efficient, responsive and integrated appliances could significantly lower and flatten demand curves.

### *Findings on Implications of Changes in Demands on Transmission*

The factors influencing transmission utilization can change in unpredictable ways. The impacts will vary depending on the type and magnitude of changes and by region due to different industry organizational structures, regulatory frameworks, resource availability and costs of power. Therefore, it is of critical importance to consumers that policymakers focus their attention on weaknesses in the transmission system as revealed in the CECA Forum's analysis of current trends in investment and practices in planning and operations. These weaknesses demonstrate the value of consumer input, the need for regulatory certainty and clear cost recovery and allocation policies to remove (or reduce) barriers to investment, and the critical importance of robust transmission planning, particularly to address critical infrastructure needs, in order to ensure that changing consumer demands are met with reliable transmission service at reasonable cost.

## Advances in Technologies – Opportunities for Consumer Benefits

This section considers advanced technologies that might be deployed within the 10-year CECA study period and the benefits to consumers that these technologies could offer. The focus of this discussion is on advanced transmission technologies that could be used to enhance transmission service to consumers. The previous discussion has identified the stresses under which the transmission system is presently operating and is likely to continue to operate unless obstacles to improved transmission planning and investment can be overcome. This discussion is intended to identify advanced transmission-related technologies that can reduce these stresses and enhance the performance of the transmission system. The next section describes the technologies, reports on their current status of development, and assesses the opportunities for deployment in the near term. The CECA Forum also identifies barriers to the deployment of these technologies, many of which are similar to those delaying other desirable improvements in the transmission system to benefit consumers.

### *The Technologies, Their Potential Benefits, and Current Status of Development*

In its review of transmission investment trends, transmission planning and operations policies and practices, and the implications of changes in demand on the transmission system, the CECA Forum found that the transmission system is being increasingly stressed by the combination of increased electricity demand due to growth in the economy and end-uses of electricity (e.g., new and greater penetration of digital equipment, appliances, etc.), new types of transactions as a result of market changes, and new operational demands due to both new transactions and changes in organizational structures. As a result, the transmission grid is being operated at levels where reliability is increasingly likely to be threatened. Technologies that can address the problems associated with operating a transmission system that has not kept pace with the demands being placed on it are presented in Tables 6 through 10. These technologies will enable increased system throughput, allow operation closer to the system limits, reduce load at critical times, permit more reliable operation of aged equipment, and reduce transmission line design and construction costs.

#### *Technologies That Enable Increased System Throughput*

The utilization of technologies that enable the existing system to carry more electricity in a reliable manner could ease some of the current and increasing stresses on the transmission system. Table 6 lists a number of promising technologies that would enable increased system throughput, and includes a description of their current status, the benefits they could provide, and the existing barriers to their deployment. Of the technologies listed here, dynamic line rating tools and video sag monitoring are in the initial stages of commercialization. Flexible AC Transmission ("FACTS") technologies are close to deployment. They have the ability to control power flows and maintain voltage stability, thereby enabling greater loading of existing lines. FACTS technologies are in the initial commercialization stages but more research is needed to reduce their costs before they can be expected to be widely installed. High capacity composite conductors and high temperature superconducting cables may be the next most developed technology in this area. They are being used in demonstration and pilot applications; again, additional work and research are needed to bring down their costs. The other technologies enabling increased system throughput are in the early stages of development and will require significant further RDD&D before they will be ready for commercial application. All of these technologies offer the promise of benefits to consumers by allowing greater utilization of the transmission system; however, the realization of these benefits by consumers will be well beyond the CECA study period.

**Table 6**
**Technologies That Enable Increased System Throughput**

| Specific Technologies | Current Status (as of 12-04) | Benefit | Barriers |
|---|---|---|---|
| High Ampacity Conductors | Demonstration | Reduce sag, permitting greater loading of lines; more corrosion resistant; longer service life | |
| High Temperature Superconducting Cables | Demonstration/pilot | Occupy less space; reduced risk of damage to environment | High maintenance costs |
| Flexible AC Transmission ("FACTS") | Initial commercialization | Increase transfer capacity; support bus voltage | More experience needed; high costs; require trained technicians to maintain |
| Dynamic Line Rating ("DLR") | Demonstration | Use real-time information, allowing higher thermal capacity of transmission lines and substation equipment | |
| Video Sag Monitoring | Demonstration | Extend effectiveness of DLR | |
| Solid State Superconducting Fault Current Limiter | In development | Limit fault current contributed by new generation; add performance beyond that of conventional breakers | |
| Solid State Power Electronics Circuit Breaker | In development | Reduce response time to faults; lower maintenance costs and improved reliability; does not use SF6 | |

Sources: J. Hauer, T. Overbye, J. Dagle, and S. Widergren, National Transmission Grid Study, Appendix A – List of New Technology Equipment to Reinforce the Grid, F-33 - F-44; D. Von Dollen, EPRI.

### *Technologies That Allow Operation Closer to System Limits*

Another group of advanced technologies will enable operators to run the transmission system closer to its limits by reducing the conservative assumptions or margins used to set existing limits, allowing these limits to be increased and thereby expanding the usable capacity of the transmission system. These technologies provide for enhanced system monitoring capabilities that will provide real time information on the status of the system. One set of technologies focuses on accurate monitoring to improve engineering management of the transmission system. These technologies will detect abnormal system conditions and will indicate when security limits are being reached in real time. They include Wide Area Measurement Systems ("WAMS") and Topology Estimators. WAMS are being introduced in the Western interconnection and DOE is designing a system for the Eastern interconnection.

A second set of technologies goes a step further, enabling operators to use real-time engineering information to assess economic conditions, including congestion of the system, to support competitive wholesale market operations. These technologies range from integrated engineering and economic methods for power system operation, to visualization and communications tools, to virtual RTO technology and market simulation. A number of these technologies are under development by the Electric Power Research Institute ("EPRI"), and a few are in the pilot or demonstration stage. A description of technologies that allow operation of the transmission system closer to its limits can be found in Table 7. Again the schedule for RDD&D is such that benefits to consumers will occur beyond the CECA study period.

**Table 7**
**Technologies That Allow Operation Closer to System Limits**

| Specific Technologies | Current Status (as of 12-04) | Benefit | Barriers |
|---|---|---|---|
| Topology Estimator | In development | Enhance security-constrained dispatch, help solve congestion problems | |
| Wide Area Measurement System ("WAMS") | Demonstration/pilot | Detect abnormal system conditions as they arise | |
| Integrated Engineering and Economic Methodology for Power System Operation | Standards and procedures being tested to ensure reliability | Enhance grid security; facilitate trading of energy and reserves; help alleviate congestion | |
| Real-time Analysis | Initial commercialization | Reduce time required to perform stability assessment for major transmission systems | |
| Visualization Tools - Community Activity Room Concept | Operating as a pilot project | Enables visualization of critical information | |

**Table 7, continued**

| Specific Technologies | Current Status (as of 12-04) | Benefit | Barriers |
|---|---|---|---|
| Communications Architecture | Working | Enables a range of technologies from smart power delivery system to technologies that improve power system operation and control | |
| Toll Collection | In development | Allow for incentive rates of return to be implemented | |
| Virtual RTO Technology | In development | Allow power industry to maintain a reliable and efficient wholesale power market during restructuring and transition | |
| Market Simulation | Prototype being used by CAISO | Enhanced analysis of transmission planning and congestion management | |
| Flexible AC Transmission (FACTS), Phase-Shifting Transformers | Tap-changing phase shifters widely available; thyristor controls in initial commercialization | Adjust power flow; faster response time; increased capacity | More experience needed; high costs; require trained technicians to maintain |
| Flexible AC Transmission (FACTS), Dynamic Breaks | Initial commercialization | Enhance power system stability | More experience needed; high costs; require trained technicians to maintain |
| Monitoring systems, Direct Measurement of Conductor Sag | Demonstration/pilot | Dynamically determine line capacity | Integration into company's energy management system required to derive full benefit |
| Monitoring systems, Indirect Measurement of Conductor Sag | Commercially available | Dynamically determine line capacity | Integration into company's energy management system required to derive full benefit |
| Monitoring systems, Indirect Measurement of Transformer Coil Temperature | Commercially available | Dynamically determine transformer capacity | Technically unreliable |
| Monitoring systems, Underground/Sub-marine Cable Monitoring/ Diagnostics | In development | Real-time sensing equipment detects hazardous operating situations and determines dynamic limits | High costs; require integration |
| Monitoring systems, Power-system monitors | Mature development | Provides regional surveillance | Requires collaboration among utilities |

Sources: J. Hauer, T. Overbye, J. Dagle, and S. Widergren, National Transmission Grid Study, Appendix A – List of New Technology Equipment to Reinforce the Grid, F-33 - F-44; D. Von Dollen, EPRI.

### *Technologies That Reduce Load at Critical Times*

Energy efficiency and load response programs can reduce load on the transmission system at critical times to enhance reliability and/or reduce costs to consumers. A variety of reliability and economic demand response programs are run by the RTOs and ISOs in organized markets and by vertically-integrated utilities where traditional industry structures prevail. To date, there is general agreement that these programs have not achieved their potential in terms of implementation and the benefits that can result for consumers. These benefits include not only support for reliability and reduced costs for electricity services, but can also include reduced environmental impacts from electricity generation.

While many of the barriers to effective use of demand-side and efficiency technologies may be policy related, there are also technical hurdles that, if overcome, would reduce the costs of these measures. To that end, a number of technologies are available and under development to support demand response and energy efficiency programs and are expected to lower the costs and ease participation by consumers. They include a variety of distributed generation technologies whose costs, with further research and development, are expected to be reduced over time, thereby enabling their widespread deployment. In addition, several energy storage technologies are under development that would offer consumers another option for reducing their electricity demand – and hence demands on the transmission system – at peak times when costs are high and reliability may be more likely to be threatened. These technologies are presented in Table 8.

**Table 8**
**Technologies That Reduce Load at Critical Times**

| Specific Technologies | Current Status (as of 12-04) | Benefit | Barriers |
|---|---|---|---|
| Demand Response Programs | Price-responsive loads available in various areas | Reduce need for new transmission, generation; provide stability for energy markets; enhance reliability; reduce emissions | Difficulties in communication and coordination; lack of experience or pre-existing standards |
| Microgrids | In development | Improve power quality, enhance demand-side management, ease peak demands resulting from randomness of load, reduce capacity rating required by some transmission facilities | High costs |
| DG and Storage Dispatch, Batteries | Widely available | Store energy to be used for emergencies or on-peak needs; real-time control applications | High costs of manufacturing and maintenance |

**Table 8, continued**

| Specific Technologies | Current Status (as of 12-04) | Benefit | Barriers |
|---|---|---|---|
| Super-conducting Magnetic Energy Storage ("SMES") | Initial commercialization | Store energy to be used for emergencies or on-peak needs; real-time control applications; provide ride-through capability for multi-second outages affecting sensitive consumer uses | High associated costs; special protection and skills needed in maintenance |
| Pumped Hydro and Compressed-air Storage | Widely available | Help shave peak; produce generation sources | Requires space; ecological impacts |
| Flywheels | Initial commercialization | Help shave peak; enhance power quality and reliability | Requires space; dangerous in case of failure |
| Intelligent Building Systems | Demonstration/pilot | Optimize energy consumption | More complex control schemes than are common at present |

Sources: J. Hauer, T. Overbye, J. Dagle, and S. Widergren, National Transmission Grid Study, Appendix A – List of New Technology Equipment to Reinforce the Grid, F-33 - F-44; D. Von Dollen, EPRI.

### *Technologies That Permit Reliable Operation of Aged Equipment*

In some regions of the U.S., parts of the transmission infrastructure are operating beyond their originally estimated lifetimes. As transmission owners and operators face the need to make decisions about replacing this equipment, new tools to assess the performance of the grid on a real-time basis can assist in determining when such replacement is necessary. In addition, technologies to optimize maintenance practices may prolong the life of transmission equipment, thereby reducing the need for replacement. In both cases, consumers benefit from reductions in economic and environmental impacts, as new construction is avoided. The current status, benefits and barriers to these technologies are described in Table 9.

### *Technologies to Reduce Transmission Line Design and Construction Costs*

The CECA Forum believes that additional transmission investment in some regions is required to provide system enhancements that benefit consumers. Technologies are under development that could reduce the cost of new transmission. These technologies include transmission design tools to enable comparisons of the costs and benefits of a variety of system design options and new equipment and materials that can reduce the costs and time needed for construction. Both will potentially benefit consumers by reducing costs and improving the timeliness of transmission construction. These technologies are described in Table 10.

**Table 9**
**Technologies That Permit Reliable Operation of Aged Equipment**

| Specific Technologies | Current Status (as of 12-04) | Benefit | Barriers |
|---|---|---|---|
| Advanced Monitoring & Diagnostic Tools (real-time) | Some software available | Optimize maintenance expenses and system reliability & performance | Existing technologies are valuable, but more R&D is needed to fully optimize life cycle |
| Tools to Optimize Maintenance Practices | Commercialization of tower design tools | Avoids new ROW issues | |

Sources: J. Hauer, T. Overbye, J. Dagle, and S. Widergren, National Transmission Grid Study, Appendix A – List of New Technology Equipment to Reinforce the Grid, F-33 - F-44; D. Von Dollen, EPRI.

**Table 10**
**Technologies to Reduce Transmission Line Design and Construction Costs**

| Specific Technologies | Current Status (as of 12-04) | Benefit | Barriers |
|---|---|---|---|
| Composite Structures | Issues still need to be addressed | Inherently insulating and not subject to corrosion; as costs decline, may reduce construction and maintenance expenditures associated with support structures | High costs |
| Transmission design tools | ABB Utility Transmission System Configuration and Design is approved for commercialization | Calculates risk and cost of each power grid design option at a fraction of the usual time | Unknown; lack of experience using new technology |
| Modular equipment | In development | Greater adaptability | Requires consideration of broad range of scenarios; time constraints |

Sources: J. Hauer, T. Overbye, J. Dagle, and S. Widergren, National Transmission Grid Study, Appendix A – List of New Technology Equipment to Reinforce the Grid, F-33 - F-44; ABB website, http://www.abb.com; D. Von Dollen, EPRI.

### *Implications for Consumers*

There are a wide variety of advanced transmission-related technologies, in various stages of development, the deployment of which could improve the operation of the transmission system, thereby alleviating existing and increasing stresses and thus improving reliability, and reducing costs for consumers. Many of these technologies offer the promise of greatly increased efficiencies in existing grid utilization, the ability to use the transmission system in new ways, reduced costs, and reduced environmental impacts. Some new transmission technologies will enable the more effective application of other technologies, such as distributed generation and demand response options. Other technologies enable real-time monitoring that will not only improve system use, but will also increase the ability of operators to detect security threats affecting the critical electricity infrastructure.

Most of these advanced technologies are still in early stages of development and will not be widely available until well beyond the CECA study period. These technologies will require significant RDD&D to achieve their potential benefits for consumers. While the benefits of most of these advanced transmission technologies will not be realized for consumers in the near term, commitment to significant funding of RDD&D is needed now in order to deliver on technology's promise in the future. The CECA Forum's review of advanced technologies reinforces its earlier findings that barriers to required or economic transmission investment must be overcome, whether for investment in conventional transmission enhancements and operations or for advanced technologies.

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The timely and effective application of advanced technologies that will provide benefits to consumers will require that barriers to transmission investment be removed in order to ensure a transmission system capable of meeting consumers' needs into the future. As the report has shown, policies must be developed to address regulatory uncertainty with respect to transmission jurisdiction, cost allocation and recovery, the status and direction of the development of wholesale power markets, and the need for robust regional transmission planning that addresses critical infrastructure needs and improvements in operations practices. In addition, if advanced transmission-related technologies are to achieve their potential, policies to overcome RDD&D funding barriers must also be developed and implemented

### *Findings on Research Development, Demonstration & Deployment Funding*

Government and private industry support for long-term funding of RDD&D is needed to ensure that advanced transmission-related technologies can achieve their potential to deliver benefits to consumers in terms of enhanced reliability, lower costs, reduced environmental impacts, and the availability of a greater variety of value-added services.

### *Findings on Policy and Regulatory Support of Advanced Technologies*

Federal and state policymakers and regulators should encourage the deployment of advanced technologies that are cost-effective today and new ones as they become cost-effective by implementing policies that clarify the conditions under which the costs of these technologies can be recovered. These conditions should require an analysis of consumer costs and benefits, and consumers should only be expected to pay for those technologies that are shown to be cost-effective in the long term.

### *Notes*

1 EIA, *Annual Energy Outlook 2004.*
2 EIA, *Annual Energy Outlook 2004,* p. 9.
3 EIA, *Annual Energy Outlook 2004,* p. 2.
4 Western Governors' Association, *Conceptual Plans for Electricity Transmission in the West,* August 2001, p. 4. Hereinafter, "WGA Report 2001."
5 WGA Report 2001, p. 4.
6 Tom Wood, "Are Electric Capacity Margins Really Growing," *Public Utilities Fortnightly,* April, 2004, p. 12.
7 ISO-NE Cold Snap Report, 2004.
8 In addition, depending on how the distributed generation is interconnected to the distribution grid, it may require reliability-related investment at the distribution level, which may offset some of the cost advantages for consumers. For example, the addition of major amounts of distributed generation on the system may cause significant increases in short circuit duties at some locations having potential reliability impacts, which could require major changes in relaying and protection systems, causing cost increases to consumers. These effects will depend on the amount of distributed generation, the size units involved, and the location on the system.
9 Eynon, Robert T., "The Role of Distributed Generation in U.S. Energy Markets" (speech) at http://www.eia.doe.gov/oiaf/speeches/dist_generation.html.

10 EIA, *Annual Energy Outlook 2004,* p. 81.

11 For example, there has been considerable debate about the Salem Harbor plant in Massachusetts, whose owners need to make a significant capital investment to meet new environmental requirements that is not economic given the old age and relatively poor efficiency of the plant. However, Salem Harbor is located in a transmission constrained area and is needed for reliability at least until several proposed transmission lines can be built. Salem Harbor's continued operation may increase costs for consumers, and yet its retirement would increase congestion costs and perhaps threaten reliability until new transmission is in place.

12 The California Energy Commission is investigating this issue in their Aging Power Plant Study.

13 No nuclear capacity is slated for retirement during the CECA study period. Should a major nuclear plant have to retire during this time it is likely to have an effect on the transmission system which is often built out around these plants.

14 EIA, *Annual Energy Outlook 2004,* p. 88.

15 EPRI. *Electric Technology Roadmaps: 2003 Summary and Synthesis - Power Delivery and Markets. Hereinafter, "EPRI, Electric Technology Roadmaps: 2003."*

16 EPRI, *Electric Technology Roadmaps: 2003.*

17 For recommendations on facilitating distributed generation, see CECA, *"Distributed Energy: Towards a 21st Century Infrastructure,"* July, 2001.

18 See Title VII, Section 710 of the *American Jobs Creation Act of 2004* (HR 4520), PL. 108-357.

# PART THREE: MOVING FORWARD

Chapter 6

# An Action Plan for Transmission Enhancements that Benefit Consumers

## Introduction

The purpose of the CECA Transmission Infrastructure Forum was to examine steps that need to be taken to ensure that the U.S. transmission system meets consumer needs over the next decade, the time period of the CECA study. The CECA Forum identified a set of consumer priorities (described in Chapter Two) for a robust transmission system, analyzed issues and trends affecting transmission requirements, and ultimately developed a set of recommendations to guide the actions of policymakers. These recommendations, described below, call for immediate and near-term actions and articulate principles to guide future policy development. The recommendations developed by the CECA Forum provide an action plan for policymakers, which will lead to a series of important results, including:

- cost-effective enhancements to the transmission system;
- cost-effective operation and maintenance of the transmission system; and
- a greater ability to meet changing demands of consumers.

This action plan will help to ensure that the physical infrastructure of the transmission system is maintained in a way that assures reliability and that supports economic transactions. The action plan proposed by the CECA Forum will enable effective results, whether in a traditionally regulated market or in a competitive market framework.

*The action plan proposed by the CECA Forum will enable effective results, whether in a traditionally regulated market or in a competitive market framework.*

The recommendations proposed by the CECA Forum address seven areas critical to the development of a robust transmission system. They are designed to ensure that the transmission system can respond flexibly and effectively to current and future consumer needs. They are designed to ensure that these needs will be met in a cost-effective manner and that benefits for consumers are ensured over the long term. The seven areas addressed in the CECA Forum's action plan are the following:

- Consumer Input;
- Reliability;
- Regulatory Framework;
- Institutional/Structural Reform;
- Cost Issues;
- Regional Transmission Planning; and
- Public/Private Funding of Advanced Technologies.

Accompanying the recommendations in each of these areas is the CECA Forum's statement of the issues which forms the basis for each recommendation. Based on the needs identified during the course of the CECA Forum's study, the action plan will result in a reliable transmission system providing reasonably priced electricity.

## CECA Forum Recommendations

Based on its analysis and findings, the CECA Forum offers the following recommendations.

## CONSUMER INPUT

### *Statement of the Issue*

Consumers benefit from the opportunity to provide timely, meaningful input into the transmission planning process and their early participation contributes to the robustness of that process. Consumers should be represented in these processes either individually, or by consumer advocates, or by organizations representing consumer interests. Education and outreach efforts are also important because local officials and electricity consumers are key constituencies affected by and affecting transmission policy in the U.S, and where applicable, in Canada and/or Mexico. While consumers may not reasonably be expected to have the capability, knowledge, or experience to develop specific transmission plans, they can provide a valuable consumer viewpoint on various transmission alternatives if they are well-informed.

In many organized markets and where there are formal planning processes, consumers have been given an opportunity to voice their opinions and concerns in transmission planning processes; in the absence of a formal planning process, consumers' opportunity to have effective input may be limited. In some regions, the timing of consumer participation may depend on the nature of the transmission planning process and may not occur until the certification or siting stage (e.g., where a traditional vertically-integrated utility model predominates). However, whether the planning process is formal or informal, consumers must be given an effective role in which their views are taken into account in the planning process. To be effective, consumers must be provided with timely and adequate information and the capability to analyze and use that information. At the same time, to benefit consumers overall, the transmission planning process should be structured so that the long term good of the whole, including generation and distribution, is properly weighed against individual costs and interests.

### *Recommendations for Consumer Input*

- FERC, the U.S. Department of Energy, state utility regulators and policymakers, regional transmission planning entities and the electric utility industry (and its related industries) should undertake efforts to educate the public, including local and municipal officials and electricity consumers generally, about the critical role that the transmission system plays in ensuring that consumers are supplied with reliable power under a variety of scenarios at the lowest possible cost to meet their electricity service needs. Consumer education efforts should be directed toward enhancing consumers' understanding of how the transmission system, in conjunction with generation and distribution, affects the electricity services they receive, and how these services relate to their own economic and social well-being, as well as that of the national economy.

- FERC, state utility regulators, and the entities responsible for transmission planning should require that transmission planning processes provide consumers with an opportunity to participate in the early stages and throughout such processes so that their input will be most effective. One means of enhancing consumer participation in transmission planning processes would be to ensure adequate funding of state consumer advocate offices and to encourage the further development and identification of other consumer groups or representatives with sufficient institutional foundation and longevity to maintain a level of

education on electric power delivery issues (including generation, transmission and distribution) that enables them to participate effectively in such processes.

- FERC and state utility regulators should require that transmission planning processes – whether in organized markets, traditional vertically-integrated utility frameworks, or hybrids of the two – include provisions to ensure the availability of adequate information and analysis to consumer representatives so that consumers have the opportunity to participate meaningfully in the transmission planning process. As applicable, regional transmission planning entities should consider waiving or lowering membership dues for consumer representatives where such dues present barriers to consumer participation.

## RELIABILITY

### *Statement of the Issue*

The reliability of the transmission system is of paramount importance to consumers to ensure uninterrupted electricity service needed to fuel the nation's economy and provide for individual consumers' economic and social well-being. Over the years, NERC has been instrumental in developing standards for the safe and reliable planning and operation of the bulk electric power system. However, NERC does not have the formal legal authority to enforce its standards. As the events of the August 2003 Blackout dramatically demonstrated, reliable operations depend on system operators complying with reliability standards, maintaining a global view of the interconnected transmission system, and having the authority and ability to take remedial actions when problems develop.

It is clear that voluntary reliability standards are no longer adequate to assure consumers of compliance with the standards under which the transmission system should be operated. Therefore, because reliability of the system is so critical to consumers, CECA supports federal legislation that provides for mandatory reliability standards that are enforced by NERC or another equivalent independent reliability organization (as defined in that legislation) which has enforceable penalties for non-compliance. Further, the public needs to know when a transmission system owner/operator does not meet reliability standards. Such failures should be made public through appropriate means. NERC has recently adopted disclosure guidelines for violations of its reliability standards, which will help to achieve this goal.

There are a variety of organizational configurations of regional reliability coordinators and control area operators within and across organized markets, traditional vertically-integrated utility frameworks, and hybrids of the two that can coordinate reliable real-time management of operations. Regardless of the regional organizational configuration, the management of transmission system planning, operations and maintenance must comply with national, regional and local reliability standards so that consumers are assured that a reliable and secure transmission system will provide the backbone needed to support their electricity service.

The CECA Transmission Infrastructure Forum supports the recommendations of the U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April, 2004*. The CECA Forum also supports the recommendations adopted and implemented by NERC as a result of its blackout investigation. Several of the CECA Forum's

recommendations on reliability reflect similar recommendations from these investigations, and are articulated here to indicate the importance of the subject matter to consumers.

### *Recommendations Related to Reliability*

- To ensure that consumers are provided with reliable transmission service to meet their changing demands, Congress must pass legislation either as part of comprehensive national energy legislation or as stand-alone legislation that provides NERC, or an equivalent independent electric reliability organization, with the authority to establish mandatory reliability standards and monitor and enforce compliance with such reliability standards, including the ability to impose meaningful penalties for violations of reliability criteria. Enforcement should also occur at the regional level subject to FERC oversight. Such legislation should allow for more stringent regional or local reliability standards where regional or local grid configurations and conditions require them to maintain system reliability. Given the interconnected and international nature of the grid, the legislation should support the development of mandatory reliability standards that will apply to the entire North American transmission grid to assure that the grid can operate effectively and reliably to the benefit of all consumers.

- Until federal legislation is enacted to provide an independent electric reliability organization with authority, FERC and state utility regulators should work with NERC and the regional reliability councils, and their counterparts in Canada and Mexico to ensure compliance with NERC and regional reliability standards, using their existing regulatory authorities so that consumers are assured that the grid is being operated in compliance with reliability standards. In particular, FERC and NERC should continue their efforts to make reliability standards more specific and enforceable. State utility regulators should continue to monitor and enforce local transmission and distribution reliability requirements. FERC, NERC and state utility regulators should make sure that non-compliance violations are made public so that consumers can be aware of such violations.

- To ensure its independence and effectiveness, NERC, or another equivalent independent electric reliability organization, should be funded by all users of the bulk power system on a fair and equitable basis. The reasonableness of such costs should be reviewed by FERC through a public process.

- As recommended by the U.S-Canada Power System Outage Task Force Report of April 2004, RTO/ISOs, transmission owners and other load serving entities responsible for transmission operations and maintenance should coordinate operational policies and practices and encourage industry utilization of "best practices" for operations and maintenance – including increased system operator training, more sophisticated system operation tools, better vegetation management, and increased situational awareness by system operators – to ensure reliable operation of the system to meet consumer needs.

## *REGULATORY FRAMEWORK*

### *Statement of the Issue*

There continues to be significant uncertainty about federal and state regulatory policy with respect to the structure of the electric power industry and markets, where they have been introduced, and which model of industry organization affords the best guardianship of consumers' interests for reliable and cost-effective transmission service. Moreover, there continues to be uncertainty about the regulatory framework in which both organized markets and vertically-integrated utilities operate. The lack of clarity with respect to the organization of the industry and markets is accompanied by uncertainty about federal and state jurisdiction over transmission investment recovery. Regulatory uncertainty acts as a barrier to transmission investment needed to provide consumers with reliable electricity service at just and reasonable rates. Many issues related to transmission planning and investment that affect consumers, such as siting, resource adequacy, and cost allocation, cut across state lines and involve federal and state regulators from multiple states. Coordination and consensus among state utility regulators and their federal counterparts will facilitate the timely resolution of these issues, contribute to regulatory certainty, foster investment, and thereby result in improved transmission services for consumers.

### *Recommendations for the Regulatory Framework*

- Congress should enact legislation that clarifies the respective roles of FERC and state utility regulators with regard to oversight of transmission investment, planning and operations, and siting. Any such legislation must direct federal land management agencies to simplify, clarify and set strict time limits for the siting process for transmission facilities on federal lands; it should also encourage state legislators and regulators to seek changes in state laws, if necessary, that would allow states to coordinate and address siting issues in a timely manner and on a regional basis, as appropriate. Congress should recognize that the roles of federal and state regulators may vary across regions given different industry organizations and market structures so that consumers will be assured the transmission system is planned and operated in the most efficient manner to meet their needs.

- FERC and state utility regulators should encourage the development of effective regional institutions, where appropriate, to facilitate (1) consensus in a manner that reduces uncertainty; (2) coordination and implementation of all aspects of transmission planning and plans within and between relevant geographic regions, and (3) avoidance of duplication of efforts so that transmission plans can be implemented in a timely and transparent manner. To the extent possible, FERC and state utility regulators should give due consideration to the recommendations of such regional institutions, and in so doing ensure that their existence does not constitute another layer of regulation or an additional forum.

### *INSTITUTIONAL/STRUCTURAL REFORMS*

#### *Statement of the Issue*

Current regulatory uncertainty about federal and state policy surrounding the appropriate framework(s) for the electric power industry is accompanied by considerable uncertainty regarding the variety of institutional, structural and organizational models – both existing and evolving – that can most effectively provide reliable electricity service to consumers at reasonable costs. This lack of clarity with respect to the organization of the industry and markets hinders effective transmission planning, discourages needed transmission investment, and creates uncertainty about which entities are responsible for implementing plans and making such investments.

#### *Recommendations for Institutional/Structural Reforms*

- FERC, together with state utility regulators, should consider the establishment of independent transmission organizations (e.g., RTOs) where they do not yet exist, or other organizational structures that may be appropriate, taking into account regional characteristics, benefits and costs, to provide cost-effective, efficient, independent administration, oversight, planning and operation of the transmission grid to meet consumer needs.

- FERC and state utility regulators should establish policies that do not favor one model over another, as long as the models provide cost-effective, efficient, independent administration, oversight, planning and operation of the transmission grid to meet consumer needs. FERC and state utility regulators should clarify the roles of various organizational structures (i.e., independent transmission companies ("ITCs"), merchant transmission companies, and transmission owned by existing vertically-integrated companies) to enhance cost-effective and reliable options for investment in the grid so that all efficient, reliable, and cost-effective service options are provided to consumers.

- FERC and state utility regulators should establish policies to ensure the existence of independent processes or institutions (where not already in existence) with the authority and accountability to implement regional transmission plans so that new transmission that benefits consumers by maintaining the reliability, adequacy and security of the system is built in a timely and cost-effective manner.

## COST ISSUES

### *Cost Recovery*

#### *Statement of the Issue*

Consumers will benefit from additional cost-effective transmission investment that results in reduced costs and maintains reliability (and improves it where current standards are not being met or where

they are threatened). Transmission investment will not take place when the rules for cost recovery and allocation are unclear, provisions for cost recovery are uncertain or inadequate, and the process for determining cost allocation is unduly contentious. Moreover, in organized markets, market-based mechanisms for transmission cost recovery (e.g., financial transmission rights) may not be adequate to provide transmission owners sufficient incentives for investment in the system. Therefore, clear, consistent and durable regulatory policies for the recovery of transmission investments made by regulated utilities must be developed and articulated to provide assurance that these investors will have a reasonable opportunity to recoup their prudently incurred costs. The recommendations on cost recovery apply to regulated transmission investments.

### *Recommendations for Cost Recovery Policies*

- FERC and state utility regulators should promulgate clearly defined policies and rules for cost recovery of transmission investments and expenditures by entities subject to their respective jurisdictions in order to facilitate investment in the transmission infrastructure needed to ensure reliable service for consumers at reasonable cost. FERC and state utility regulators should ensure that cost recovery policies and rules are based on a durable regulatory framework that provides a reasonable opportunity to recover prudently incurred costs for transmission investments and expenditures associated with owning, operating and maintaining the transmission system to meet reliability needs, demonstrated long term cost-effective economic upgrades, critical infrastructure investments, and research, development, demonstration and deployment that produce clear benefits for consumers, while ensuring just and reasonable rates for consumers.

## *Cost Allocation*

### *Statement of the Issue*

Clear cost allocation rules are needed so that consumers, market participants, and investors will know who is responsible for paying the costs of transmission needed for both reliability and economic upgrades. Clear allocation rules can help to increase regulatory certainty, facilitate the transmission planning process, and foster investment.

### *Recommendations for Cost Allocation Policies*

- FERC and state utility regulators should establish clearly defined policies and rules for allocating transmission costs in order to facilitate timely investment in both reliability and economic upgrades that are demonstrated to be cost-effective to provide consumers with reliable service at reasonable cost.

- To ensure that costs are equitably assigned to various classes of consumers, FERC and state utility regulators should specifically address issues of cost allocation and distributional equity, i.e., how to balance benefits to the system as a

whole against the potential for any unreasonable intra- or inter-regional cost shifting that could occur. In any cost allocation process, regulators should:

— Recognize regional differences and historical transmission planning and cost allocation processes, and the transmission priorities established through these processes;

— Recognize and take into account the fact that beneficiaries of a particular transmission investment can change over time; and

— Ensure that existing consumers are not allocated costs unreasonably where the industry structure has changed or is changing (e.g., shifts to organized energy markets, etc.).

## *Performance-Based Incentives Regulation*

### *Statement of the Issue*

The current regulatory framework focuses on the examination of expenditures made by utilities for infrastructure investment and operations and maintenance of the transmission system. As with any system of cost recovery, it provides transmission owners/operators with certain incentives for investment and operations and maintenance expenditures and practices. Generally, however, the traditional regulatory framework for transmission cost recovery does not explicitly address issues related to transmission owner/operator performance. As regulators seek to reduce uncertainty with respect to cost recovery for transmission investment and operations and maintenance, it may be possible to develop more innovative "carrot and stick" regulatory mechanisms for transmission cost recovery that relate such recovery to performance and encourage utilities (through symmetrical rewards and penalties) to improve transmission operations and maintenance practices, as well as efficiently and cost-effectively expand the transmission grid where it is warranted. Under any such regulatory framework, the goals to be met, the performance metrics to measure their achievements and the method for allocating net benefits actually achieved between consumers and transmission owners must be clearly specified. In order to facilitate this, clear and consistent performance metrics for transmission should be established and transparently reported so that consumers can understand the quality of service they are receiving from the transmission system. This increased transparency will better inform consumers with respect to transmission performance and therefore lead to greater focus on key areas where improvement is required, whether or not more innovative regulatory mechanisms are adopted.

### *Recommendations for Performance-Based Incentive Regulation*

- FERC and state utility regulators and policymakers should recognize that traditional cost-based regulation of transmission may not necessarily provide sufficient incentives to achieve superior operating results or to efficiently expand the transmission grid to maximize the benefits to consumers. Accordingly, FERC and state utility regulators should consider establishing carefully crafted regulatory mechanisms that provide incentives for the efficient operation, mainte-

nance, and expansion of the transmission grid. Regulators should implement regulatory mechanisms with symmetrical penalties and opportunities for rewards. These mechanisms should encourage strict adherence to accepted transmission operations and maintenance practices that comply with NERC reliability standards by providing for monetary penalties or other sanctions for transmission owners/operators for poor performance so that consumers are assured the system is operated and maintained efficiently, and by affording transmission owners/operators the opportunity to share in the net benefits that result from their superior performance.

- FERC and state utility regulators and policymakers should ensure that regulatory mechanisms establish clearly defined and transparently reported performance metrics that relate to outputs that consumers value (e.g., efficiency, costs), reflect superior performance, do not result in unintended consequences, encourage owners/investors to pursue the lowest cost options and advanced technology options where there are demonstrated benefits to consumers. These regulatory mechanisms should provide incentives to transmission owners/investors to improve operations and maintenance practices and/or expand the grid in the most cost-effective manner. The net benefits that result from superior performance should be shared between consumers and transmission owners in an equitable fashion. There are a number of ways in which the sharing of net benefits can be accomplished, including explicit earnings sharing mechanisms, rate freezes and price caps.

## *REGIONAL TRANSMISSION PLANNING*

### *Statement of the Issue*

The August 2003 Blackout clearly demonstrated the interconnected nature of the transmission grid and highlighted the critical need for coordinated transmission planning and improved operations across regions to provide consumers with reliable electricity service throughout North America. In addition to providing purely local benefits, transmission investment often benefits consumers far from the physical location of the facilities. The planning processes of organized markets, large vertically-integrated utilities, large federal entities such as Bonneville Power Authority and Tennessee Valley Authority, and smaller entities, such as many municipal utilities, must identify and include projects with broad regional benefits, while recognizing individual companies' autonomy over transmission investment with purely local benefits. In doing so, consumers will be assured that the most cost-effective investments to the transmission system are made in an efficient and timely manner.

Planning also affects the costs of transmission service to consumers because of the substantial lead time required for transmission investment, and because transmission investment has the potential to affect future investment in generation and other resources. Therefore, transmission planning must take into account the different types of new resources that are likely to be built or implemented by others (or transmission owners themselves), including remote resources such as mine-mouth coal, wind generation, load-center generation, distributed generation, demand response, energy efficiency, and merchant transmission projects; the interdependencies of the transmission system with the fuel delivery systems,

i.e., natural gas pipelines, and the effect of fuel price levels and volatility on power flows; and the impacts on the environment of transmission system upgrades.

Likewise, transmission planning must take into account other major changes to the electricity system, such as generation retirements (with their implications for fuel diversity as well as demands on the transmission system), that will affect transmission plans and operations. Transmission planning processes in organized markets will differ in complexity from transmission planning by vertically-integrated utilities or other transmission-owning utilities in regulated markets, driven in part by the involvement of multiple stakeholders. The planning process under both organizational structures should consider views from a variety of key stakeholders. However, there needs to be a mechanism in the planning process to reach decisions when individual stakeholder interests result in a stalemate because of conflicts with broader national or societal public interests.

Finally, consumers rely on electricity for virtually all underlying functions of the economy – e.g., banking, commerce, traffic systems, air traffic control, medical systems and equipment, and more. The lives of consumers would be severely disrupted if their electricity service was unavailable for an extended period of time due to a terrorist attack directed at the transmission grid. The August 2003 Blackout clearly demonstrated the economic consequences of blackouts. While the costs to enhance the transmission system's ability to respond to security threats must be weighed against the likelihood of such a threat, these enhancements can be viewed as an insurance policy against the significant harm to consumers that could result from such an unlikely event. Therefore, national security must be taken into account in transmission planning and investment, with a particular focus on identifying and addressing critical infrastructure needs.

An overall national view of transmission needs should be developed to facilitate and support regional transmission planning processes. A National Power Survey similar to those conducted periodically in past years should be the basis for assessing the results of regional planning processes and can assist in identifying national power system and policy requirements needed for the future. This would not be a blueprint to be followed blindly but would examine the key alternatives available and provide guidelines for future technical developments and policies. Such a survey is particularly appropriate at this time, given the recent market structure and organizational changes in the transmission system and the current heightened need to address critical infrastructure and national security issues. While the various entities (e.g., RTO/ISOs and vertically-integrated utilities) are engaged in the development of regional transmission planning processes, a review and analysis on a national basis is useful for evaluating the national configuration of the grid, including the arrangement and size of the existing three regional grids, the effect of potential types and locations of future generation, the costs and benefits of implementing various market policies, the location and type (AC or DC) of interregional ties, what transmission voltages should be used for major future transmission additions, and the future impact on such design considerations as short-circuit duties and protection schemes. Such a survey can help to avoid the development of a patchwork grid with concomitant long term problems. The survey will provide a framework for coordinating the various regional plans, eliminating the need for high-cost transformations as much as feasible, and other unnecessary intra- and inter-regional costs.

### *Recommendations for Regional Transmission Planning*

- Given the interconnected nature of the grid, coordinated transmission planning should take place on a regional basis, recognizing that such regional planning processes may vary considerably across regions with different industry organizations and market structures. FERC and state utility regulators should identify the entities that are responsible for transmission planning (e.g., RTOs/ISOs, vertically-integrated utilities and other transmission owners/operators) and that are accountable to consumers and regulators for ensuring that necessary transmission facilities – for both reliability and economic purposes – are (1) identified through a transparent process that includes meaningful input from consumers early in that process, (2) constructed in a timely manner to ensure reliable, adequate and secure electricity service for consumers, and (3) designed to meet NERC reliability standards for planning and operations. The entities responsible for regional transmission planning should be cognizant of neighboring regions, of the fact that regions will evolve and their boundaries will change, and of the need for inter-regional coordination.

- Because consumers require a transmission system that is secure from natural, cyber and physical threat, the entities responsible for transmission planning and operations, in conjunction with the Department of Homeland Security and the Department of Energy, should expedite and coordinate ongoing efforts to include national security or physical and cyber-security considerations in their planning for transmission at the earliest stages of the planning process.

- The entities responsible for regional transmission planning should ensure that the planning process includes a mechanism whereby decisions that are needed to enable transmission projects to move forward can be made in a timely manner in which individual interests can be considered fairly along with the broader public interest.

- The U.S. Department of Energy should undertake a periodic (e.g., every 10 years) National Power Survey – similar to those conducted in the past – to facilitate regional planning processes that form the basis for developing future transmission plans and policies. The Department of Energy should engage the expertise of ISOs/RTOs and other regional transmission coordination entities.

- Oversight of regional transmission planning and coordination is the primary responsibility of NERC and the regional reliability councils, however FERC should have oversight responsibilities. State utility regulators and any regional institutions should be involved in the regional transmission planning process early so that public policy considerations with respect to region-wide synergies and efficiencies can be achieved and to coordinate the transmission planning process with policymakers' views of the region's long-range generation and demand resource needs.

- Regional transmission planning processes should take a broad view of the system, including taking into account local plans, future needs, operations of interconnected regions (including North American cross-border issues), retirements

and additions of generation within regions, the development of non-wires options, fuel price levels and volatility, fuel availability, environmental impacts, and their potential effects on transmission operations and constraints so that consumers are provided cost-effective service at reasonable prices. Regional transmission planning should also take into account the role of transmission investment in mitigating market power by providing access to a greater number of options for meeting consumers' electricity service needs.

- Because of the importance of cost-effectiveness to consumers and the effects of the production and delivery of electricity services on the environment, regional transmission planning processes should take into consideration the development of resources that can affect transmission system utilization and the need for additional transmission. These resources include demand response, distributed energy resources, generation built on the constrained side of transmission bottlenecks, and energy efficiency options and other "non-wires" solutions, recognizing that these resources may or may not be satisfactory substitutes for transmission and that they will affect the need for and the costs of transmission investment.

- So that consumers' needs for reliable, adequate and secure service are cost-effectively met, the entities responsible for transmission planning should enhance and implement transmission planning processes that address the need for reliability upgrades and opportunities for demonstrated, long term, cost-effective economic upgrades (that meet the needs of consumers and can be appropriately distinguished from reliability upgrades). These entities should ensure that the transmission planning process leads to a transmission system that has the ability to respond flexibly to future changes in the electricity system that are likely to occur, such as fuel prices and availability, and to future changes in consumer demands on that system. Particularly, in organized markets with a process intended to elicit market-based transmission investment, the entities responsible for regional transmission planning should develop a process that describes what and how steps will be taken to ensure that the necessary investments are made if the market does not offer a solution to the need for an identified reliability or economic upgrade. The transmission planning entities should take into account the fact that market participants will naturally want to wait for someone else to build and pay for these upgrades if this appears likely (or such provisions make it a near certainty) and should ensure that the process to respond to market inaction minimizes the likelihood of this result.

- So that consumers in the United States and bordering nations receive reliable, secure transmission service, FERC and appropriate state utility regulators should explore a cross-border cooperative approach to evaluate the need for investment in transmission enhancements required for reliability, and where cost-effective, economic purposes, and where a need is identified, encourage such investment. Such cooperation could include assuring effective participation of Canadian and/or Mexican entities in regional transmission planning processes and streamlining or otherwise improving the efficiency and timeliness of the siting process for the construction of cross-border transmission facilities.

## PUBLIC/PRIVATE FUNDING OF ADVANCED TECHNOLOGIES

### *Statement of the Issue*

The deployment of advanced transmission and related technologies offers the potential for significantly improving the operation of the transmission system, thereby alleviating existing and increasing stresses on the system, improving reliability and reducing costs for consumers over time. Advanced transmission and related technologies also offer the promise of enhancing the transmission and electricity system's capabilities to deliver to consumers new value-added services in the future. However, current barriers to the deployment of advanced transmission and related technologies that can deliver benefits to consumers include uncertainty with respect to energy and regulatory policies, availability of funding, and rules related to cost recovery and allocation at both the federal and state levels. Moreover, all of these advanced technologies will require significant research, development, demonstration and deployment to achieve their potential benefits for consumers. Tapping the possibilities of these technologies for consumers will require a significant, sustained commitment of government and industry to RDD&D funding over the long term to develop advanced technologies that can become cost-effective.

### *Recommendations for Public/Private Funding of Advanced Technologies*

- Congress should make a long term commitment to adequately fund RDD&D of advanced transmission and related technologies, which complements private sector initiatives (by the electric utility and related industries) a key element of any national energy legislation, in order to explore and develop the potential of advanced technologies that enhance the operations of the transmission grid, improve the reliability, security, and safety of the grid, and reduce costs, thus providing benefits to consumers both during this period of transition and in the long term.

- If Congress is going to continue to influence energy policy through tax credits and subsidies for various technologies, it should clarify the policies related to transmission- and electricity-producing technologies so that investors can make rational resource decisions, and provide consumers with the benefits of implementation of advanced technologies that result in increased efficiency of the grid. Any such credits and subsidies should be made available to all for-profit and not-for-profit entities on a comparable basis.

- FERC and state utility regulators should encourage the wider deployment of existing cost-effective advanced transmission technologies that will enhance the reliability and reduce the costs of the transmission system for consumers' benefit over the long term.

- FERC and state energy policymakers should explore opportunities for cooperation with bordering nations for both investment in advanced transmission technologies and transmission RDD&D – either through government programs, industry support, or government-industry partnerships – to provide consumers with the benefits of the efficiencies that would result from such cooperation.

## Conclusion

The CECA Transmission Infrastructure Forum has identified the need for immediate or near term action in several areas to ensure that the transmission system will be adequate to meet consumers' current and future needs. The CECA Forum has also developed specific recommendations for policymakers, regulators, and transmission owners and operators on how to meet those needs. These recommendations resulted from the CECA Forum's analysis of current transmission investment trends, and planning and operations policies and practices. This analysis indicated that uncertainties with respect to electricity market structures, industry organization, and cost recovery and allocation policies are hindering investment in transmission to support current demands on the system and to ensure the system's ability to respond flexibly to future demands. The analysis also identified the need for improvements in transmission planning and operations policies and practices to provide consumers with reliable service at reasonable costs.

Reliable electricity service is a necessity of modern life. Recent events, including the August 2003 Blackout, have demonstrated the potential costs to consumers of a transmission system that may not be strong enough, resilient enough, or operated well enough to provide them with reliable electricity supplies at reasonable costs. Unless action is taken now, the quality of electricity service to consumers is likely to decline, undermining reliability and increasing costs to the detriment of consumers' well-being.

# Appendix A

# Regional Transmission Planning and Operations Practices and Summaries

## BACKGROUND

The CECA Transmission Infrastructure Forum asked the members of its System Planning and Operations Working Group (Working Group) to review current regional transmission planning and operations practices, using the NERC regions as areas of geographical division. As discussed in the report, *Keeping the Power Flowing: Ensuring a Strong Transmission System to Support Consumer Needs for Cost-Effectiveness, Security and Reliability,* the CECA Forum recognized that NERC regions are not responsible for transmission planning per se. However, it was agreed that the NERC regions would serve as the geographic areas for review of current transmission planning and operation practices for this report. This Appendix is a compilation of the regional summaries that were prepared by various members of the CECA System Planning and Operations Working Group. The summaries were then used as the basis of analysis undertaken by the CECA Transmission Infrastructure Forum in its examination of regional transmission planning and operations issues.

Members of the Working Group volunteered to develop the summaries and followed an outline of issues which focused on consumer input questions as well as technical issues. In certain instances, the questions asked in the outline did not apply to the region. CECA wishes to thank all of the volunteers who extended great time and effort to develop the regional summaries.

The purpose of developing regional transmission planning and operations summaries was to compare and contrast current transmission planning and operations practices, on a region-by-region basis. Common themes, best practices and gaps or weaknesses emerged and were discussed in this Report. The analysis developed as a result of the summaries served to help the CECA Forum formulate many of the public policy recommendations put forward in this Report.

As mentioned above, the 10 NERC regions and ISO/RTOs were used as the basis for review of current transmission and operation practices. The following outline was used as a guide for that review; however, as practices in each region differ, a region's examination may include topics not covered in the suggested outline. It is provided here for the reader to see how each summary was developed.

## A. Review of Current Transmission Planning Process of NERC Regions, ISO/RTOs

**1. Responsibility for Planning in the Region**

***Key Items:***

- Describe who is responsible for regional planning.

- How do stakeholders have input into the planning process?
- How are stakeholders chosen to be part of the planning process?
- To whom are the stakeholders accountable?

**2. Regional Planning Process/Stakeholder Input**

***Key Items:***

- How is the process for planning documented?
- How was the process created/approved?
- How do stakeholders/consumers have input to creating/amending the process?
- How are final decisions made?
- Does the process include an appeal, and if so, to whom?
- How do stakeholders/consumers have access to decisions?
- What is the role of local, state, and federal regulators in the process?
- If the planning committee does receive consumer input, at what phrase in the planning process does this occur?

**3. Inventory of Specific Regional Practices**

***Key Items:***

- Is there a process for determining need for new transmission/enhancements and how do stakeholders have access to it?
- Does the process for determining need include reliability, economic, and generator interconnections? What variations exist, if any, in the process?

**a) Planning Horizon**

***Key Items:***

- Describe the scope of the planning process and planning horizon.
- How is responsibility assigned for the project?

**b) Principles of Region**

***Key Items:***

- What are the planning principles of the region?

**c) Inventory Regional Cost Allocation/Cost Determinations**

***Key Items:***

- What is the process for determining ownership?
- What is the process for determining cost responsibility?
- How do stakeholders have input into the process?
- What is the region's approach to pricing transmission service?

## B. Review of Operations Procedures of NERC Regions, ISO/RTOs

**1. Standards and Compliance**

***Key Items:***

- Are there set standards in place for transmission system operations and maintenance?
- Does the region set standards that exceed the requirements set by NERC?
- Is responsibility for operations and maintenance clearly defined for all portions of the system or is it assumed to be associated with ownership?

- If these responsibilities are shared between co-owners and/or ISO/RTO, are roles and responsibilities clearly defined?
- Do consumers have input into the process of setting standards, assuring compliance?
- Are there clearly defined consequences set in place for non-compliance that would ensure/compel compliance?

## C. Sources Used in Summary of Region

# Electric Reliability Council of Texas (ERCOT)

*Prepared by: Kiah Harris, Burns & McDonnell*
*Reviewed by: Nick Akins, American Electric Power*
*(as of 10/14/04)*

**Definition of ERCOT Market Participants:**

a. Generation Resources (GRs)
b. Qualified Scheduling Entities (QSEs)
c. Competitive Retailers (CRs)
d. Transmission Service Providers (TSPs)
e. Distribution Service Providers (DSPs)

## A. Review of Current Planning Process of ERCOT

### *1. Responsibility for Planning in the Region*

The ERCOT reliability region became the ERCOT ISO in 2001. As an ISO, the regional planning process within the ERCOT area is supervised and authorized by the ERCOT. This responsibility and authority is provided in the Texas Public Utility Regulatory Act (PURA) and the Public Utility Commission of Texas (PUC) substantive rules. ERCOT has three regional planning groups (RPGs). Projects are submitted to ERCOT staff for determination of merit. If the ERCOT staff recommends the project for review, the RPGs are responsible for reviewing projects. The TDSPs have ultimate responsibility for identifying the necessary upgrades to maintain reliability according to the NERC Table 1 criteria as amended by ERCOT planning protocols.

Stakeholders within ERCOT include the market participants and other members of ERCOT. The make-up of the membership of ERCOT presently consists of 152 members. ERCOT membership includes 38 cooperatives, 19 municipals, 9 investor owned utilities, 18 independent generators, 17 independent power marketers, 24 independent retail electric providers, 26 consumers, and 1 adjunct. The Board of ERCOT consists of the following:

(a) One (1) Independent Representative and one Segment Alternate
(b) One (1) Independent Generator and one Segment Alternate
(c) One (1) Independent Power Marketer and one Segment Alternate
(d) One (1) IOU and one Segment Alternate
(e) One (1) Municipal and one Segment Alternate
(f) One (1) Cooperative and one Segment Alternate
(g) Three (3) Consumers: OPUC, one Commercial, and one Industrial
(h) Three (3) Independent Directors
(i) The CEO as an *ex officio* voting member
(j) The Chair of the PUC as an *ex officio* non-voting member

Each director gets one vote. A quorum is 50 percent and it takes a two-thirds majority to pass a motion.

Members are also elected from the general membership to make up the Technical Advisory Committee (TAC). Each TAC Representative shall be entitled to one vote on matters submitted to TAC. Fifty-one percent of the eligible representatives of TAC shall constitute a quorum for the transaction of business. Affirmative votes of sixty-seven percent of the eligible Representatives of TAC shall be the act of TAC. For the consumer segment, corporate members of each sub-segment elect its Representatives. For any sub-segment in which there are no corporate members, the consumer directors appoint such representatives. For the residential, commercial and industrial sub-segments, the TAC Representative seats are as follows:

(i) Two Representatives of Industrial Consumers
(ii) One Representative of Small Commercial Consumers
(iii) One Representative of Large Commercial Consumers
(iv) One Representative of Residential Consumers
(v) The Public Counsel or his/her designee as an ex officio voting member

The stakeholders of ERCOT have input to the planning process through the regional planning groups, which are open to anyone in ERCOT to participate, and the actions of the ERCOT membership voting on projects to be moved forward. Consumers are also represented by the PUC in the regional planning groups as directed by the PURA. ERCOT is responsible to the PUC.

### *2. Regional Planning Process/Stakeholder Input*

The planning process is documented in various ERCOT publications, primarily the ERCOT Power System Planning Charter and Processes document. The process was created by the ERCOT staff/membership and approved by the ERCOT board. Approval by the PUC was also provided.

Stakeholders have input to the creation of the process by their membership in ERCOT, the board of ERCOT and representation by the PUC. Amendments come through their participation in ERCOT membership/board. Changes to the Operating Guides, of which the planning process is a part, can be changed by submission proposed revisions to the Reliability and Operations Subcommittee who will either reject or submit to the TAC and the Board for approval.

Following is the specific process:

- Proposed Operating Guides Revision(s) are submitted via email to ERCOT.
- The Reliability and Operations Subcommittee (ROS) reviews and recommends action.
- ERCOT Subcommittees review and comment.
- Comments are submitted via e-mail to ERCOT.
- ERCOT posts and forwards comments to ROS.
- ROS reviews all comments and the decision reached on each comment is posted.
- ROS submits recommended Operating Guides Revision(s) to the TAC for approval.
- ERCOT Board of Directors is advised of the TAC approved Operating Guides Revision(s).

Final decisions on planning processes are made by the Board and PUC. Final decisions on the ultimate construction of the project are made through the Certificate of Conveniences and Necessity (CCN) process under the direction of the PUC. The planning process itself does not have an appeal process. There are challenge processes within the CCN process. Ultimately appeals of the PUC decisions could be taken to court.

During the planning process, there is little to no involvement of the local, state or federal regulatory agencies. After the project is identified, the local and state regulators become involved during the project siting and CCN process.

Consumers can be represented from the beginning of the planning process through their involvement in the regional planning groups for project planning and during the CCN process while the project is being developed.

### *3. Specific Regional Practices*

Projects are submitted to ERCOT by market participants and stakeholders.
Consumers can influence the determination of need through the planning process by participation on the regional planning groups and during the CCN process. All projects are submitted to ERCOT staff for dissemination to the respective regional planning group. There is no difference in the planning process once the project is submitted for review.

#### *a) Planning Horizon*

ERCOT uses a 10-year planning horizon to review system adequacy. If a project is approved, it is assigned to the default providers who are the owners of the endpoints of the project. If they do not accept the project, then ERCOT can determine an alternate provider.

#### *b) Principles of Region*

ERCOT adopted the NERC criteria in Table 1 with some modifications for multiple contingencies. Essentially it adheres to the N-1 criteria.

#### *c) Cost Allocation and Cost Determination*

If the project is accepted for development by the default providers, then they own it. If it is not accepted by the default owners, then ERCOT will assign another entity to own the project. Cost is recovered by the transmission rates established by the PUC. Stakeholders can intervene at the PUC and during the CCN process.

## B. Review of Operations Procedures of ERCOT

### *1. Standards and Compliance*

ERCOT essentially adheres to the NERC standards for operations. No specific maintenance standards are provided by ERCOT. Operations are defined by market participants, as maintenance standards are not a NERC function. Consumers have input to the standards through their representation in ERCOT and the PUC. See change process for the guides above. If the member does not comply with ERCOT guides, then their membership can be revoked.

## C. Sources Used in Summary of ERCOT Region

a. Power System Planning Charter and Processes, October 22, 2003.
b. Operating Guides, April, 2004.
c. Amended and Restated By Laws of ERCOT, October 15, 2002.
d. Report on Existing and Potential Electric System Constraints and needs within the ERCOT Region, October, 2003.

# Florida Reliability Coordinating Council (FRCC)

*Prepared by: David Mohre, National Rural Electric Cooperative Association*
*(and others at NRECA)*
*(as of 10/13/04)*

## A. Review of Current Planning Process of FRCC

### *1. Responsibility for Planning in the Region*

The FRCC has no centralized regional planning process. Each individual utility is responsible for planning for its own system's needs, in accord with FRCC/NERC standards and procedures, and state/regulatory requirements as appropriate. FRCC consolidates the individual plans of the utilities into a single FRCC model for purposes of performing various FRCC and NERC reliability studies for the region. Any stakeholder input into the planning process must be given as part of the state or local regulatory processes for any related electric rate cases, facilities siting proceedings, or other as appropriate.

### *2. Regional Planning Process/Stakeholder Input*

As mentioned above, there is no regional planning process in FRCC. The FRCC performs various reliability studies according to FRCC and NERC objectives, and produces reports on these study results that are available to the NERC/FRCC utilities. Stakeholder input and involvement on the underlying plans of the utilities comes through the regulatory proceedings for each individual utility, as previously mentioned.

### *3. Specific Regional Practices*

The FRCC has a role in the coordination of transmission planning in the region. The FRCC Engineering Committee (EC) is responsible for implementing standards and procedures for the coordination and planning of a reliable bulk electric system in the region. These activities also ensure that FRCC meets the requirements in the NERC Planning Standards.

The EC has working groups that facilitates the related activities. These are:
- Stability Working Group
- Transmission Working Group
- Resource Working Group

The major elements of the FRCC Planning Coordination that these technical groups use to assess the reliability of the region are a regular set of studies, including:
- Seasonal Transmission Studies (Summer and Winter)
- Ten-Year Transmission Study (Annually)
- Stability Studies
- Under-frequency Studies
- Resource Adequacy Studies (Filed w/FL PSC each July)

### *a) Planning Horizon*

See item 3.

### *b) Principles of Region*

The principles for planning in the region are related to complying with the various voltage, thermal, stability and other limits that are needed to preserve reliability, under normal, single and multiple contingency conditions.

### *c) Cost Allocation and Cost Determination*

Cost allocations are directly tied to the individual utility tariff provisions, and any adjustments that may be incurred on a case-by-case basis through any related regulatory or legal proceedings. There is no "regional cost allocation methodology."

## B. Review of Operations Procedures of FRCC

### *1. Standards and Compliance*

The FRCC provides outage coordination support. Operating entities provide data on planned transmission and generating unit outages for the next 12-month period on a monthly basis. A transmission line outage and generating unit outage report is then produced on a monthly basis and shared with the "reliability only group" for use in operating and planning studies.

All operations and maintenance responsibilities are borne by the transmission owners and operators.

Regional standards for the FRCC are based on the NERC standards, policies and procedures. In some cases the FRCC requirements are more stringent than NERC's. These requirements are determined in the FRCC technical committees as outlined above.

## C. Sources Used in Summary of FRCC Region

The FRCC staff was consulted in the completion of this review, as well as some regional utilities.

# ISO-New England (ISO-NE)

*Prepared by: Judy Chang, The Brattle Group*
*(as of 11/19/04)*

## Overview of the ISO-NE Region

The Independent System Operator of New England Inc. (ISO-NE) was created in 1997 and it serves as the control area operator, transmission service provider, market administrator, regional transmission planner and NERC Reliability Coordinator for New England, covering six states, including Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Prior to establishing ISO-NE, the New England Power Pool (NEPOOL) was created in 1971, integrating the majority of New England's investor-owned and municipal systems, to establish a central dispatch system and to enhance the region's overall system reliability and reduce production costs. NEPOOL is a voluntary association of more than 200 entities engaged in the electric power business in New England. As of 2004, The ISO-NE's footprint has over 31,000 megawatts (MW) of generating capacity and serves more than 14 million people in the six states. In 2004, ISO-NE was forecast to have a peak demand of about 25,846 MW and approximately 131 million megawatt-hours (MWh) of energy sales.

ISO-NE is responsible for New England's transmission planning. It began its Regional Transmission Expansion Plan (RTEP) process with the approval of the 66th Agreement amending the Restated New England Power Pool (NEPOOL) Agreement (RNA) in September 2000. ISO-NE is subject to regulation by the FERC, and ultimately, all NEPOOL market rules and tariffs are subject to FERC approval.

## A. Review of Current Planning Process of ISO-NE

### *1. Responsibility for Planning in the Region*

Each year, ISO-NE prepares a Regional Transmission Expansion Plan (RTEP) to meet the need of the New England electric system. The RTEP process in New England has evolved over the years. The ISO-NE states that it adheres to detailed procedures, guidelines and criteria that are established by NERC, Northeast Power Coordinating Council (NPCC), and NEPOOL; and they include specific requirements to demonstrate the adequacy and acceptability of proposed system expansions or changes.

Generally, the ISO-NE's RTEP process is designed to identify the power system's problems and needs. It is used to alert market participants to the identified problems and to inform them of opportunities to address those needs. This means that ISO-NE uses the RTEP process to seek market solutions, including investment in generation, merchant transmission facilities, and demand (or load) response programs that would maintain power system reliability and improve wholesale electricity market efficiency. At the same time, the RTEP process assembles and presents a coordinated transmission plan that identifies appropriate projects for ensuring reliability and economic efficiency for the entire New England region ***if*** the market does ***not*** respond with adequate solutions to the identified system needs. In other words, the RTEP identifies what the regulated transmission solutions would be if market solutions do not present themselves.

Accordingly, the RTEP process begins with a System Need Assessment or a System Plan. In the process of developing the System Plan, the ISO gathers input from a committee called Transmission Expansion Advisory Committee (TEAC). The TEAC is composed of stakeholders including NEPOOL Participants (such as generator owners, marketers, load serving entities and transmission owners), governmental representatives, state agencies (including those participating in the New England Conference of Public Utilities Commissioners), representatives of local communities, and consultants.

On an on-going basis, if the market responds with acceptable proposals, ISO-NE updates its proposed regulated transmission plan. For example, when anticipated market conditions change, ISO-NE provides the TEAC with updated system assessments and any revised status of possible transmission solutions. This means that when generation is built or retired, demand response programs are activated, merchant transmission is developed, or market fundamentals such as fuel price, existing generator performance, load forecast, or regulatory rules change, the proposed transmission solutions may change. Once it is determined that certain regulated transmission solutions are needed, regulated transmission owners must construct those facility enhancements or upgrades specified in the RTEP, subject to siting requirements and regulatory approvals.

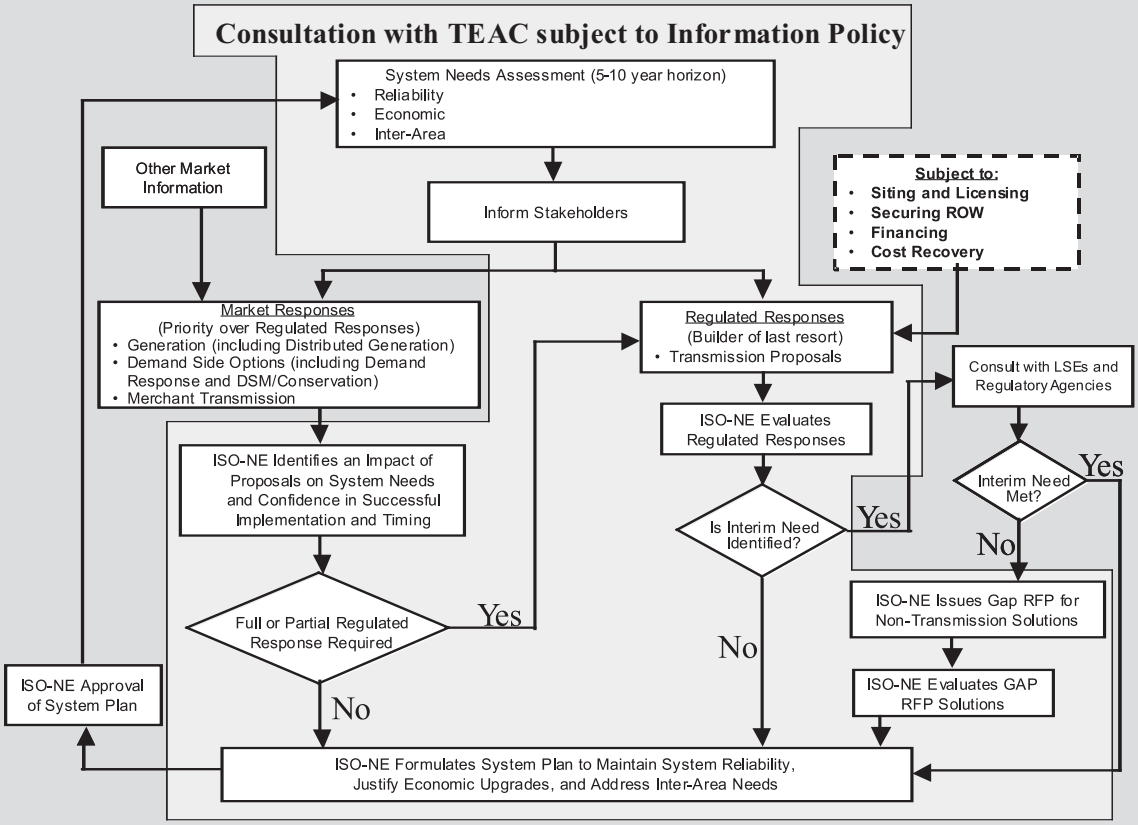
ISO-NE recognizes that the time required for implementing transmission projects is usually very long, thus sometimes it may seek out *interim* solutions to meet the needs and problems identified in the RTEP process. In those cases, ISO-NE, after consultation with affected parties and state government entities, may issue a "stopgap request" for proposals to develop an interim solution. These may include temporary peaking generation facilities or demand-side curtailment to be located in specific areas in the region. For example, in early 2004, ISO-NE issued a "gap" request for proposal (RFP) for new emergency resources (quick-start generation or demand-side reduction) for Southwest Connecticut. It received multiple proposals and accepted eight suppliers for up to 300 MW of capacity.

The proposed transmission projects described in the annual RTEP also are subject to review by NEPOOL (pursuant to Section 18.4 of the Restated NEPOOL Agreement) which ensures that the proposed projects will not have any negative reliability impacts on the New England network. The project are also subject to NEPOOL review (pursuant to Section 15.5 of the Restated NEPOOL Agreement) to ensure that the *most economical* transmission projects are selected and that prudent costs for the Pool Transmission Facilities (PTF) are rolled into the regional transmission rate, i.e., the "Regional Network Service" or "RNS" rate.

ISO-NE also coordinates RTEP study results with existing transmission systems and with interregional and local expansion plans. ISO-NE exchanges information with New England's neighbors, including New York, Quebec, the Maritimes, Ontario, and PJM both bilaterally and as a part of the more formal Northeast Power Coordinating Council (NPCC) process. Thus, the RTEP assessments are intended to address local, regional, and multi-regional considerations.

Following is a process flow diagram for the RTEP process currently conducted in New England.

**Figure 1**
**ISO-NE's RTEP Process**




Source: Diagram from ISO-NE's RTEP 2003

## *2. Regional Planning Process/Stakeholder Input*

The TEAC meets regularly throughout the year and the meetings are open to any interested party. The TEAC does not necessarily have decision-making responsibilities, but rather, is set up to provide ISO-NE with the industry response to ISO-NE's studies and proposals. Accordingly, the TEAC provides stakeholder input to ISO-NE on issues related to the planning assumptions, reliability and congestion modeling assumptions, on transmission planning studies, and on others. ISO-NE also solicits input from the public through the public meeting conducted by a subcommittee of the ISO-NE's Board of Directors. Local, state and federal regulators and consumer groups all can but are not required to contribute suggestions in the RTEP process by participating in the TEAC meetings. Each year, ISO-NE develops an RTEP report that includes an assessment of the adequacy of the region's electric system and a list of proposed regulated transmission projects. Each year, the RTEP report is submitted for approval to ISO-NE's Board of Directors. Prior to the Board's approval, a meeting is held at which a subcommittee of the Board receives comments from the public. Thus, through the TEAC meetings and through the public comment process, the ISO-NE solicits input from regulatory and consumer groups. Currently, there does not appear to be an *ex post* appeals process by which market participants who disagree with the ISO-NE's assessments or recommendation can demand revisions. The ISO tries to

resolve most of the issues prior to issuing the RTEP report. Through its system planning process, the ISO is the *de facto* lead decision-maker in the transmission planning process for New England.

## 3. Specific Regional Practices

As indicated above, ISO-NE has the overall responsibility for determining the need for new transmission and system enhancements and does so via the RTEP process. The RTEP process is designed to determine the need for transmission upgrades for the purpose of *maintaining regional reliability* and *economic efficiency.* In addition, the RTEP takes into consideration upgrades made necessary by *generator interconnections.*

### Reliability and Economic Upgrades

The ISO, in preparing the Transmission Plan identifies, to the extent practical, the anticipated benefits of the proposed upgrades. According to the NEPOOL tariff, *reliability upgrades* are defined as those upgrades that are not required by the interconnection of a generator but are necessary to ensure continued reliability of the NEPOOL system, taking into consideration load growth and known resource changes. They include upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels and those facilities required to provide adequate thermal capability and local voltage levels that cannot be achieved otherwise for purposes of long-term planning studies. Again, ISO-NE uses Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of NERC and NPCC, other applicable local reliability criteria, and NEPOOL system rules to define its reliability needs.

*Economic upgrades* are defined formally as those transmission upgrades that are not related to the interconnection of a generator, and are designed to reduce or eliminate congestion cost such that the net present values of the reduction in congestion cost exceeds the net present value of the cost of the transmission upgrade. There are two major upgrades underway in New England, namely the NEMA upgrade and the SWCT upgrade. It appears that the ISO has determined that both of these projects, when implemented, will provide reliability and economic benefits to the region, and thus, based on New England's default cost allocation method (described later) the cost of these projects will be rolled-in to existing rates.

### Generator Interconnection Upgrades

ISO-NE also has the lead responsibility for interconnecting new generating units. Prior to 1998, generators interconnecting to the NEPOOL PTF were required to be "fully integrated" with the regional grid; they were required to demonstrate that their capacity could reach the aggregate load throughout New England under both normal and high volume transfer conditions. As such, interconnections to the NEPOOL grid were subject to a "deliverability" requirement, similar to the one currently in place in PJM-East. However, because generators seeking interconnection access in New England were willing, in some cases, to accept existing transmission constraints and thus gain some access to the NEPOOL grid without necessarily reaching the system's aggregate load (or paying for the upgrades required to do so), the "Full Integration Standard" came under attack. Ultimately, the Full Integration Standard was replaced, in 1998, by the Minimum Interconnection Standard. Under the Minimum Interconnection Standard, an interconnection applicant is required to demonstrate that the interconnection of its unit to the NEPOOL PTF will not degrade the existing transfer capability of the PTF and non-PTF. If this test is satisfied, the interconnected generator gains full market rights, including becoming eligible to receive

installed capacity payments (ICAP) as an ICAP supplier and to participate in the operating reserves market.

A new generator or a proposed enhancement to an existing generator must submit to ISO-NE an interconnection application. The application must include information necessary for ISO-NE to conduct a system impact study. Through the system impact study, ISO-NE determines what additions or modifications to the transmission system are required to permit the proposed generator to interconnect while maintaining system reliability, stability, and operability. If the ISO determines that transmission modifications or upgrades are necessary, then the generator owner would be required to pay for at least a portion of those transmission upgrade costs, however, if the ISO-NE determines that those upgrades will also provide reliability or economic benefit to the system, the associated upgrade costs are rolled into the system-wide rate. Each transmission owner is responsible for negotiating an interconnection agreement with a requesting generator.

In a November 2004 order, FERC directed ISO-NE to consider revising its market rule to include some form of deliverability test. FERC recognizes that even though a substantial amount of new generation (almost 10,000 MW) has entered into New England between 1999 and 2004, most of that generation was not constructed where it is most needed. Thus, FERC directs ISO-NE to define an improved "deliverability" test (one with higher interconnection obligation than the Minimum Interconnections Standard) and determine the conditions that generators must satisfy to qualify for ICAP.

### *a) Planning Horizon*

According to the NEPOOL tariff, ISO-NE will conduct a comprehensive transmission expansion and enhancement study at least once every three years and each plan will account for at least ensuing five years of load and capacity forecasts, proposed generation additions and retirements, proposed Merchant Transmission Facility additions. In practice, the ISO has produced a RTEP report every year (from 2001 through 2004) and each report covers a planning horizon of 10 years. A more limited study also can be conducted if a need for additional transfer capability is identified or new constraints are identified as a result of generation additions/retirements, new load forecasts or addition of transmission facilities. As a recent example, in the 2003 RTEP process, ISO-NE conducted a resource adequacy analysis by sub-areas of New England, covering 10 years, from 2003 through 2012. The ISO also conducted a congestion analysis by sub-areas for the same 10-year period. The congestion analysis shows projected locational marginal prices (LMPs) and the expected flows over major New England transmission interfaces, to identify where potential transmission bottlenecks may occur. However, the ISO acknowledges that there is a high degree of uncertainty with the assumptions used in this 10-year forecast. For shorter-term technical systems network analysis, ISO-NE works with transmission owners to conduct them. These technical studies tend to be engineering analyses that identify and address thermal, voltage, stability, and short-circuit issues on the systems. Together with transmission owners, through these detailed analyses, ISO-NE identifies potential upgrades that would increase transfer limits when necessary.

As an example, using economic modeling for sub-areas of New England, ISO-NE recently showed that specific transmission facilities in the Southwest Connecticut sub-area might cause significant future congestion when the ISO operates the system according to reliability criteria. ISO-NE then identified the need to conduct a more detailed analysis. Then, in collaboration with Northeast Utilities (NU) and United Illuminating Company (UI), the transmission owners in the Southwest Connecticut sub-area, ISO-NE conducted a more detailed planning study of the sub-area and published the findings in a study. This study was developed with public input, was subject to public comment, and was conducted

*outside* the scope of the annual RTEP report. In addition, the study went through a peer review so that other ISO-NE market participants have an opportunity to comment on the assumptions and modeling techniques used in the study. The detailed analysis focused on the transmission system in the local area at a level of detail not studied in the ISO's RTEP process. Those details include transmission system operating constraints within the southwestern region of Connecticut.

### *b) Principles of Region*

ISO-NE is responsible for preparing the NEPOOL Transmission Plan by consolidating regional transmission needs into a single plan, based on maintaining the NEPOOL Control Area's reliability while accounting for economic and environmental considerations. As the ISO conducts its analysis and puts together the region's transmission plan, it solicits the market to respond to its transmission needs. Generally speaking, the planning process is designed to provide a "request for solutions" by sending the needed market signals to generators, merchant and elective transmission providers and distributed resources through regularly held meetings and the RTEP report. Only where there is insufficient response to the request for solutions, the ISO recommends that the regulated transmission companies complete the needed upgrades.

### *c) Cost Allocation and Cost Determination*

At the end of 2003, FERC approved an ISO-NE sponsored transmission cost allocation proposal. Under the approved proposal, participant funding will be used for transmission upgrades that are private, market-based and when beneficiaries can be clearly identified. Specifically, participant funding would apply to elective transmission upgrades, generator interconnection related upgrades, merchant transmission, "local benefit upgrades" and "localized costs." Local benefit upgrades are upgrades to the transmission system that are rated below 115kV and localized costs are costs associated with regional upgrades that ISO-NE determines are not reasonable to be supported on a regional basis. If and when beneficiaries cannot be clearly identified, transmission upgrades that produce regional benefits would receive regional cost support, and transmission upgrades that provide only local benefits would receive local cost support.

NEPOOL's cost allocation methodology requires an interconnecting entity (e.g. a new generator, or merchant transmission) to bear all costs of sole use, direct assignment facilities as well as all costs for Network Upgrades. In addition, the generator is required to pay all annual costs, including federal and state income taxes, operations, maintenance, administrative and general expenses, annual property taxes, and other related costs allocable to the direct assignment facilities and Network Upgrades, subject to a market compensation mechanism that refunds some of the costs related to upgrades that increase the transfer capability of the PTF. Again, if the System Operator determines that a generator interconnection-related upgrade needed to meet the Minimum Interconnection Standard provides benefits to the system as a whole, the upgrade costs are rolled into the system-wide rate.

In a nutshell, FERC approved a New England transmission allocation plan that defaults to regional or pool-wide cost support for transmission facilities rated at 115kV or above, and for those upgrades that the ISO identifies as providing regional reliability and/or economic benefits. For merchant transmission projects, generator interconnection costs and facilities that provide only local benefits, costs would be recovered through participant funding. This plan allows for the rolling in of costs associated with reliability upgrades and for economic upgrades when participant agreement does not occur. Under this plan, ISO-NE is the entity that determines the costs of regulated transmission upgrades and which also determines whether certain costs should be included in the transmission rate charged to all customers in New England or only to customers within a portion of the region.

## B. Review of Operations Procedures of ISO-NE

### *1. Standards and Compliance*

ISO-NE is the regional security coordinator for New England Power Pool. As security coordinator, ISO-NE is responsible for real-time monitoring of system conditions (including voltage, frequency, transmission and generation availability, and power flows) to anticipate potential reliability problems, and for directing and coordinating relief procedures to respond to transmission loading problems (such as halting additional interchange transactions and implementing emergency procedures). ISO-NE performs such functions through its security-constrained unit commitment and dispatch and by administering an LMP-based congestion management. ISO-NE has operational authority over the transmission facilities under its control and also has exclusive authority for maintaining day-to-day reliability in the New England service area.

In 2004, ISO-NE received a conditional approval from FERC to be an RTO. To receive such an approval, a RTO must meet four essential characteristics and perform eight functions. These essential characteristics and functions were established by FERC in Order 2000, issued December 20, 1999. One of the essential characteristics is the RTO have operational authority over all transmission facilities under its control. Another essential characteristic is the RTO have exclusive authority for maintaining the short-term reliability of the transmission grid under its control. To demonstrate that it has exclusive authority over short-term reliability, a RTO must: (1) have exclusive authority for receiving, confirming, and implementing all interchange schedules; (2) have the right to order the redispatch of any generator connected to transmission facilities it operates if necessary for the reliable operation of those facilities; (3) have authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards; and (4) if the RTO operates under reliability standards established by another entity (e.g., a regional reliability council), the RTO must report to the Commission if these standards hinder its ability to provide reliable, non-discriminatory and efficiently priced transmission service.

Transmission owners must operate their transmission facilities in accordance with NEPOOL Operating Manuals and follow ISO-NE's instructions related to their responsibilities, including but not limited to: (1) performing the physical operation and maintenance of their transmission facilities; (2) directing changes in the operation of transmission voltage control equipment; and (3) when necessary, taking the additional actions required to prevent an imminent emergency condition or to restore the ISO-NE's transmission grid to a secure state in the event of a ISO-NE system emergency. Transmission owners are subject to numerous responsibilities and obligations under the NEPOOL Transmission Tariff (as well as a code of conduct). For example, transmission owners must establish the ratings of their transmission facilities and provide these ratings to ISO-NE. Transmission owners also must plan and coordinate transmission system outages with other transmission owners as required. Facility outage requests must be submitted to ISO-NE in accordance with ISO-NE requirements.

## C. Sources Used in Summary of ISO-NE Region

a. ISO-New England 2001 Regional Transmission Expansion Plan (RTEP01), October 19, 2001.
b. ISO-New England 2002 Regional Transmission Expansion Plan (RTEP02), November 7, 2002.
c. ISO-New England 2003 Regional Transmission Expansion Plan (RTEP03), November 13, 2003.
d. New England Power Pool FERC Electric Tariff, Fourth Revised Volume No. 1.

e. Connecticut Siting Council Docket No. 217, Application for a Certification of Environmental Compatibility and Public Need for an Electric Transmission Line Facility Between Plumtree Substation, Bethel and Norwalk Substation, Norwalk, Prefiled Testimony of ISO New England Inc. by Stephen G. Whitley, March 12, 2002.
f. FERC Order on Complaint and the Proposed Amendments to the NEPOOL Tariff and the Restated NEPOOL Agreement, Docket No. ER03-1141 and ER03-222, December 18, 2003.
g. FERC Order on Large Generator Interconnection Procedures and Large Generator Interconnection Agreements, Docket No. ER04-433-000 and ER04-432-000, November 8, 2004.
h. FERC Order No. 2000 (Regional Transmission Organizations), Docket No. RM99-2-000, December 20, 1999.

# Midwest Independent System Operator (MISO)

*Prepared by: Nina Plaushin, American Transmission Company and*
*Rich Sedano, Regulatory Assistance Project (on behalf of DOE)*
*Reviewed by: Larry Mansueti, DOE Office of Electric Transmission and Distribution*
*and Karen Hill and Tom Kay, Exelon*
*(as of 11/18/04)*

## A. Review of Current Planning Process of MISO

### *1. Responsibility for Planning in the Region*

#### *Plan Approval*

The MISO has a Board comprised of seven members. Board members are elected by signatories to the transmission owners' agreement from a slate of candidates developed via an independent executive search.[1] The MISO Board ultimately approves the MTEP on recommendation from the planning staff.

#### *Planning Organizational Structure*

MISO is responsible for regional transmission planning within its footprint. The MISO planning staff is responsible for producing this plan.

A primary source of information is the system plans that the member systems prepare. MISO "rolls up" these plans into an aggregate system.

The Planning Support Group (PSG) advises the planning staff through open meetings to vet technical issues. Participation in the PSG is primarily technical staff of utilities and transmission owners. The PSG includes the work of the Expansion Planning Group in its advice to the planning staff.

The Expansion Planning Group (EPG) provides guidance to MISO's effort to implement its Plan in a coordinated way, recognizing that MISO serves in multiple reliability regions. The EPG works in open meetings and is primarily composed of representatives of transmission owners. An important element of the EPG charge is to act as a conduit of information from the NERC reliability regions in MISO. The Expansion Planning Group reports to the (PSG).

MISO maintains a Planning Advisory Committee (PAC), which provides input of a more non-technical variety to plans as they are developed by staff. The PAC is a designated stakeholder group including a transmission owner, an independent power producer, a power marketer or broker, a municipal utility or transmission dependent utility, a state regulator, a large customer, a non-government consumer group, and a non-government environmental group.

In most recent documents and reports, MISO has added the Organization of MISO States to the list of entities from which it will take advice on its planning process. The mechanism to deliver this advice remains to be developed.

In approving the Transmission Expansion Plan (MTEP) in committee, only MISO members may vote for approval (one vote per member). Stakeholders who have been active in MISO's process to date have been transmission owners, IPPs, power marketers, load serving entities, and some state representatives.

### *2. Regional Planning Process/Stakeholder Input*

Many of the projects MISO considers are already in the planning process of member transmission owners, and are identified in information delivered to MISO. MISO seeks to identify projects that address challenges to applicable reliability standards, that mitigate significant transmission congestion, and that enable use of attractive energy resources. It is up to transmission owning companies to execute these projects. At this time, there is no process for the MISO to take action to implement MTEP projects on its own.

Individual companies are responsible for meeting reliability standards of NERC, regional reliability councils, and local systems. MISO is responsible to offer coordination and other assistance to support the individual companies. The Planning Support Group, informed by the Expansion Planning Group, assesses the reliability information developed by MISO staff and by the reliability regions and provides input to MISO addressing reliability needs. The first (2003) MTEP included a single contingency assessment, and did not conduct a comprehensive regional reliability studies. These studies will be completed in 2004 and bi-annually thereafter.

Addressing the issue of economic transmission constraints, MISO in its first MTEP identified 19 significant points of congestion, or flowgates. These points were identified based on a high incidence of activation of Transmission Loading Relief (TLR) procedures. MISO identified several planned and proposed projects that have the potential to improve market efficiency by reducing transmission constraints at a majority of these flowgates. Since the MTEP was published in mid-2003, MISO has established more formal study groups to develop and evaluate various exploratory projects aimed at improving market efficiency. Such projects are evaluated through an analysis that estimates the cost of congested flow gates within the RTO and compares that cost to the capital cost of projects aimed at relieving the congestion.

MISO also identified prospective useful energy resources in the region, notably, significant coal deposits and significant wind domains. Identification of these resource classes emerged from stakeholder input. As these tend to be in areas with low customer loads, it is likely that transmission will be needed to develop these resources and bring the power to load centers. MISO designates planned and proposed projects serving this purpose, which it calls "Projects of Commercial Interest." In this part of its planning work, MISO engages in forward-looking resource planning, including deploying a production cost simulation with a security-constrained dispatch. MISO evaluates sensitivities of various potentially cost-effective generation scenarios and resulting transmission that may emerge in the MISO region. MISO expressly recognizes that it is filling a gap in coordinating generation and transmission planning in this part of its work.

The Planning Advisory Committee reviews all this work in development and provides advice to MISO. MISO aims to provide reliable information to decision-makers regarding ways to solve system problems and take advantage of market opportunities. At this time, this takes the form of a discussion of "Exploratory Transmission Projects." MISO's planning process is insufficiently developed such that "rec-

ommendations for development," or, more directly, "need determinations," are not offered, nor is there a resolution about whether recommendations will be offered, and if so, how.

### *Stakeholder/Consumer Input*

There are several opportunities for public input in the MISO process. First, consumers may provide input to local plans developed by individual transmission owners; to the extent the companies offer such opportunities.[2]

Second, consumers may participate in the MISO committee process (development of the MTEP). Large customers (rather than small retail customers) tend to populate the committee process. Transmission owners and market entities (Load Serving Entities, generators and marketers) are the most involved; regulatory and other interested parties have also participated.

Third, meetings of the Planning Support Group and the Expansion Planning Group are open, though the content of these meetings tends to be technical in nature. The EPG is currently meeting on a monthly basis. The PSG meets every other month. Any interested party can attend and participate in EPG or PSG meetings.

Fourth, there is a Planning Advisory Committee, where a diverse group of designated stakeholders has the opportunity to comment on the work of the Planning staff.

Fifth, MISO solicits public input after the first draft of the MTEP is released – as it provides specific projects/analysis in which to comment.

Sixth, while not structurally part of its organization, MISO participates in public forums, explains its planning process and results and receives reactions from participants.

## ***3. Specific Regional Practices***

The Midwest Independent System Operator's (MISO) planning process is new and evolving. MISO assists states and market participants by providing an independent assessment of reliability and economic opportunities. MISO employs a "bottom-up" planning approach, relying on transmission owners within the MISO footprint to provide their individual plans for transmission enhancements (local plans). MISO evaluates local planning information to assure that they are in compliance with NERC Planning Standards and to identify regional projects ("exploratory study projects") that relieve congestion and could have significant regional benefits.

### *a) Planning Horizon*

The MTEP has a 5-year planning horizon. Projects included in the MTEP address imperatives to maintain reliability, reduce congestion and improve access to lower cost energy supplies.

### *b) Principles of Region*

The Transmission Expansion Plan is designed to ensure the reliability of the Transmission System that is under the operational and planning control of the Midwest ISO. Additionally, the plan is to identify expansion that is critically needed to support the competitive supply of electric power by this system.

The Plan is to consider all market perspectives, including demand-side options, generation location, and transmission expansion.[3] Another objective of the plan is to enable third parties to build and own transmission.

MISO approved its first Transmission Expansion Plan (MTEP-03) on June 19, 2003. MISO plans to issue a MTEP each year. In consideration for the effort involved in analyzing both congestion and reliability, the MTEP will emphasize each in alternating years. The first MTEP fully developed a congestion-related analysis. The second will develop a more comprehensive reliability assessment, and so on.

### *c) Cost Allocation and Cost Determinations*

The Regional Expansion Criteria and Benefits Task Force (RECB), a recently formed group, is responsible for developing cost allocation proposals. The RECB reports to the MISO Advisory Committee.[4]

The RECB is charged with defining criteria to be used to justify inclusion of transmission expansion proposals in the MTEP, and to recommend a mechanism to allocate the costs of these expansions. The criteria are intended to address all expansion included in the MTEP – ongoing commitments, new requests for interconnection of delivery service, and other needs identified by stakeholders. The goal of the RECB task force is to identify an analytical process that can be uniformly applied to any transmission expansion proposal and will measure the reliability benefits, the economic (non-reliability) benefits and the extent to which individual entities share in these benefits. The RECB is expected to meet monthly and complete its work by December of 2004.

Currently, MISO uses the cost allocation measures FERC adopted in its *pro forma* generator interconnection rulemaking (Order 2003). MISO transmission service is priced using a license plate methodology. There are discussions ongoing regarding alternative pricing methods. RECB will remain in existence for at least a year, during which it is expected to report out its results, and the need for continuing it will be evaluated at that time.

## B. Sources Used in Summary of MISO Region

a. MTEP-03.
b. PowerPoint: ISO Initial Transmission Expansion Plan Scope & Schedule Planning Advisory Committee January 17, 2002.
c. PowerPoint: MTEP – 03 (this is apparently a presentation to the MISO Board, apparently prepared on June 26, 2003).
d. Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation (the TOA).
e. Draft Regional Expansion Criteria and Benefits Task Force (RECB) Charter Revised Draft dated: 02/23/04.
f. Draft Charter Goals, suggested for PAC discussion by Teresa Mogensen 1/17/02.

# New York State Independent System Operator (NYISO)

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*(as of 10/18/04)*

## Overview of the New York State Independent System Operator

In New York State, the current planning process is conducted entirely by the New York Independent System Operator, Inc. ("NYISO"), under New York State Reliability Council ("NYSRC") and Northeast Power Coordinating Council ("NPCC") requirements and pursuant to various NYISO planning manuals. NYISO's current planning process results in an annual study report.

The NYISO and various market participants, including the eight Transmission Owners in New York, negotiated and drafted proposed NYISO tariff procedures and agreements to establish a new, formal New York regional planning process that will involve all market participants in the planning process. These proposed tariff revisions are pending review at the Federal Energy Regulatory Commission ("FERC"). FERC issued a deficiency letter to NYISO on October 19, 2004, asking NYISO to submit further explanation and support for the pending planning process filing. This summary provides an overview of the current NYISO planning process and the planning process elements currently on file and under review at FERC. This summary also provides an overview of operations procedures in New York.

## A. Review of Current Planning Process of NYISO

### *1. Responsibility for Planning in the Region*

#### *a) The Current Planning Process in New York is Conducted by the NYISO Pursuant to Guidelines Established by NPCC and NYSRC*

The New York State Bulk Power System primarily consists of 4,039 miles of 765kV, 345kV, and 230kV transmission and is supplemented by about 6,750 miles of 138kV and 115kV transmission, a small portion of which is considered to be bulk power transmission.[5] A 500kV tie-line connects the Branchburg station in the Pennsylvania-New Jersey-Maryland Interconnection ("PJM") to the Ramapo station in southeastern New York. Also included in the New York State Bulk Power System are a number of large generating units that are generally, but not necessarily, 300MW or larger. The New York State Bulk Power Transmission System consists of the transmission facilities included in the New York State Bulk Power System.

The NYISO is required to conduct an annual assessment of the reliability of the planned New York State Bulk Power Transmission System, in accordance with established NPCC, NYSRC and NYISO criteria, rules, and procedures.

NPCC, a regional council of the North American Electric Reliability Council ("NERC"), has established criteria for the design and operation of interconnected power systems ("NPCC Criteria").[6] As part of its

ongoing reliability compliance and enforcement program, NPCC requires each of the five NPCC Areas (i.e., New York, New England, Ontario, Quebec, and Maritimes provinces) to conduct and present an annual Area Transmission Review, which is an assessment of the reliability of the planned bulk power transmission system within the Area in a future year. The process and requirements for this assessment are outlined in the Guidelines for NPCC Area Transmission Reviews.[7]

In addition to the NPCC Criteria, the NYSRC has established rules for planning and operating the New York State Power System ("NYSRC Reliability Rules").[8] The NYSRC Reliability Rules are consistent with, but in certain cases more specific or stringent than, the NPCC Criteria. The NYSRC also has a compliance monitoring program, and the NYISO provides its annual transmission reliability assessment to the NYSRC in accordance with that program. NYISO's annual Area Transmission Review focuses primarily on NPCC Criteria and related NYSRC rules.

The Guidelines for NPCC Area Transmission Reviews require each Area to conduct a Comprehensive Review at least every five years and either an Interim Review or an Intermediate Review in each of the intervening years between comprehensive reviews, as appropriate. Each review examines a single year. The most recent Comprehensive Review was presented by the NYISO staff in July 2000 and covered the year 2006.[9] Since then, three Intermediate Reviews were conducted in 2001, 2002 and 2003, covering years 2006, 2007 and 2008, respectively.

The NYISO Area Transmission Reviews examine the New York Control Area's ("NYCA") bulk power transmission system, through a system representation that is developed from the NPCC 2002 Base Case Development library. The representation for NYCA is based on NYISO's FERC Form 715 filing with changes made to reflect most recent updates provided by the Transmission Owners. The NYCA representations also reflect the conditions reported in NYISO's Load and Capacity Data Reports.[10]

NYISO's New York Area Transmission Review includes an examination of the proposed transmission and generation projects throughout the period of the review that have met two "milestone" requirements. The first milestone is the approval by the NYISO Operating Committee of a System Reliability Impact Study ("SRIS"). The second milestone is demonstration of satisfactory progress in the regulatory process. For large generation projects, this milestone is achieved by obtaining acceptance of the Article X siting application before the New York State Public Service Commission.

NYISO's Area Transmission Review evaluates the performance of the NYS Bulk Power Transmission System in accordance with NYSRC Reliability Rules. Specific guidelines for voltage and stability analysis are found in the NYISO Transmission Planning Guidelines, which are Attachments E and F of the NYISO Transmission Expansion and Interconnection Manual.[11] These NYISO Guidelines conform to the NPCC Criteria, Guidelines for NPCC Area Transmission Review, and NYSRC Reliability Rules. The NYISO Guidelines provide additional details regarding NYISO's methodology for evaluating the performance of the NYS Bulk Power Transmission System.

The procedure used to evaluate the performance of the NYS Bulk Power Transmission System consists of the following basic steps: (1) develop a mathematical model (or representation) of the New York State and external electrical systems for the period of the study, (2) develop various load flow base cases to model the system conditions (load and power transfer levels, commitment and dispatch of generation and reactive power devices) to be tested, and (3) conduct load flow and stability analysis to determine whether or not the transmission system meets NYSRC and NPCC criteria for thermal, voltage and stability performance.

Currently, individual Transmission Owners in New York state plan, develop and implement projects designed to improve reliability. However, there is currently no formal region-wide procedure to resolve reliability concerns discovered through the NYISO's annual Area Transmission Review.

### *b) A Revised New York Planning Process is Under Review at FERC*

On August 20, 2004, the NYISO filed with FERC proposed tariff amendments to establish a comprehensive planning process for reliability needs in New York. The filing, which is pending review by the FERC, provides a mechanism whereby the NYISO, its Market Participants, and the NYPSC will cooperate in planning for the long-term reliability needs of the New York bulk power system. The essential steps in the proposed planning process include the identification of system needs, the development of proposals for both market-based and regulated solutions to those needs, the evaluation of proposals solutions by the NYISO, and the implementation of regulated solutions by New York Transmission Owners as a backstop when market-based projects do not resolve anticipated reliability deficiencies.

The August 20 filing was the result of protracted negotiations between the NYISO and interested market participants, including the Transmission Owners. The resultant proposed planning process, once approved by FERC, will be implemented through additions to the NYISO's Open Access Transmission Tariff. The revised planning process will continue to include the current NYISO planning review procedures, but will expand and define the roles of Transmission Owners and other interested market participants in addressing and resolving reliability deficiencies discovered by the NYISO's annual Area Transmission Review procedures. The following provides an overview of the elements of the revised planning process that was filed by the NYISO. Because the August 20 filing remains pending before FERC, the final planning process that is implemented may vary somewhat from the proposals discussed herein.

Under the proposed revised planning process, the NYISO will continue to be responsible for the preparation of the reliability needs assessment and reliability plan for bulk transmission facilities, in accordance with the procedures described in part A, above. Additionally, the Transmission Owners will continue to plan for their individual transmission systems, including their bulk transmission facilities. However, a new, formal procedure is being developed for the solicitation by the NYISO of proposed projects to resolve reliability needs, which are to be implemented by Transmission Owners, generators, demand side managers, or other market players, depending on which project NYISO determines is the preferred method of meeting reliability.

Under the proposed procedures, stakeholders will have input into the proposed planning process through participation in a variety of working and voting committees administered by the NYISO. Any NYISO stakeholder (being a party to the NYISO Agreement) may participate in the stakeholder committees and working groups. Additionally, interested non-parties (i.e., the New York State Public Service Commission) may participate on a non-voting basis. Stakeholders are bound by the terms and conditions of the NYISO Agreement.

For example, the NYISO gathers input and approval for proposed planning solutions through several committees and working groups, including but not limited to the Electric System Planning Working Group ("ESPWG"), the Transmission Planning Advisory Subcommittee ("TPAS"), the Operating Committee and the Management Committee. The ESPWG is an advisory consensus-building group focusing on the planning process and treatment of economic issues (e.g., historical congestion reporting). TPAS is an advisory group focusing on system modeling and solutions related to reliability. The Operating Committee and the Management Committee are formal voting committees and part of the

NYISO governance structure. These committees are expected to consider and vote on the reliability needs assessment and reliability plan before formal approval by the NYISO Board.

With respect to regional planning in New York, the current proposal for the revised planning process establishes certain defined roles for state regulators. For example, it is proposed that the New York State Department of Public Service and the New York State Public Service Commission will provide oversight regarding review of non-Transmission-Owner regulated proposals for reliability needs, administer resolution of disputes regarding conclusions or recommendations of the reliability needs assessment, and administer resolution of disputes regarding proposed solutions to meet reliability needs.

### *2. Regional Planning Process/Stakeholder Input*

The proposed planning process will reside within the NYISO Open Access Transmission Tariff ("OATT"), which is regulated by FERC. The proposed process was developed through the NYISO governance structure, which requires affirmative vote by the Management Committee and approval by the NYISO Board. Through the NYISO governance structure, stakeholders voted on the proposed amendments to the NYISO OATT, which were filed with FERC by NYISO following approval by the Management Committee and the NYISO Board.

Under the proposed planning process, stakeholder input is provided to NYISO through the working and voting committees at several stages of the planning process, including a review of NYISO's reliability analysis, provision of commercial assumptions, development of scenario analysis, and review of the reliability needs assessment and reliability plan. Presentation in public venues may also occur.

In general, consumer interests are represented through the End Use Consumer voting sector within the NYISO governance structure. Entities that qualify for the End Use Consumer sector include large consumers, small consumers, government/state consumer advocates, and retail aggregators.

Final decisions regarding reliability projects to be implemented will be made by the NYISO Board, with disputes taken before the NYPSC or FERC. In general, there is a NYISO Board appeal process in the NYISO Agreement. The planning process includes additional specific dispute resolutions provisions, with disputes regarding the reliability needs assessment and reliability solutions referred to the NYPSC, and disputes related to NYISO's compliance with its tariff referred to FERC. Decisions will be made publicly available.

State regulators will (a) provide oversight regarding review of non-Transmission-Owner regulated proposals for reliability needs; (b) administer disputes regarding conclusions or recommendations of the reliability needs assessment; and (c) administer disputes regarding proposed solutions to meet reliability needs. The proposed planning process must be approved by FERC to become part of the NYISO OATT.

### *3. Specific Regional Practices*

Under the proposed new planning process, the NYISO will undertake an annual reliability needs assessment, in coordination with the stakeholder working committees, that models the expected performance of the bulk power system against reliability criteria. The NYISO analysis will include plans of the Transmission Owners for modifications to their individual systems. The NYISO will identify instances where reliability criteria are not met and include them in a published reliability needs assessment, to be

called a "Comprehensive Reliability Plan."

The proposed planning process currently under negotiation focuses exclusively on reliability needs and solutions, with the exception of some historical congestion reporting. Economic needs are not yet identified for the purpose of regional planning. Generator interconnections are separately studied and modeled as input to the planning analysis. Economic need and upgrades are not considered at this time.

The proposed planning process provides for three levels of proposed solutions to meet reliability needs identified by the NYISO in the Comprehensive Reliability Plan. First, Transmission Owners will be required to provide "backstop" regulated proposals for transmission or non-transmission projects that could be implemented to resolve an identified reliability need. Second, NYISO will request and analyze proposals from the market for proposed projects intended to meet an identified reliability need. Third, should a market proposal be deemed by NYISO insufficient to meet the identified reliability need, NYISO will request proposed regulated solutions, including but not limited to transmission, generation or demand side management proposals, to meet the identified reliability need. As part of this process, non-Transmission-Owners are permitted to develop and submit to NYISO proposals for regulated solutions to reliability needs. Such proposals may include generation, demand-side solutions, or other solutions. The NYISO will make the final decision as to whether a market proposal will satisfy the identified reliability need and may be implemented. If not, the NYISO will make the final decision as to instead select a regulated backstop or alternate regulated proposal to be implemented to meet the identified reliability need.

### *a) Planning Horizon*

In New York, the planning horizon is a 10-year period, with a focus on the resource and transmission adequacy of the bulk power system. The NYISO has lead responsibility for planning, both currently and under the proposed revised planning process. Under the proposed planning process, the NYISO will designate the responsible Transmission Owner to prepare or to proceed with a regulated solution to an identified need (or select an alternative regulated solution), should a market-based proposal fail to meet the need. The responsible Transmission Owner will normally be the Transmission Owner in whose transmission district the NYISO identifies a reliability need.

### *b) Principles of Region*

The planning principles in New York include:

- Confirmation of applicable reliability criteria;
- Reporting of historical congestion; and
- Resolution of needs from a regional perspective.

### *c) Cost Allocation and Cost Determinations*

There is no explicit process in New York to determine ownership of facilities. Under the proposed revised planning process currently being negotiated, cost responsibility for regulated solutions will be determined by a cost allocation methodology to be developed. The proposed planning process contains cost allocation principles intended to guide the future development of such specific cost allocation methodology. The current principles include that beneficiaries shall be allocated costs based on their contribution to the need.

Stakeholders have access to the process through the working and voting committees that make up the

NYISO governance structure. The cost allocation methodology is expected to be developed with stakeholder input.

Currently, transmission revenue requirements are primarily recovered through bundled transmission /distribution license plate rates to each customer of the individual utility to which the customer is connected under existing rate plans. Wholesale municipals pay for transmission service through a Transmission Service Charge collected by the Transmission Owners under the NYISO OATT.

How costs for new transmission constructed pursuant to the new reliability planning process will be specifically collected is not yet known. Transmission Owners may file at FERC for establishment of a rate mechanism separate from the NYISO OATT Transmission Service Charge that shall be designed to be limited to the recovery of transmission related costs incurred pursuant to the Comprehensive Reliability Plan.

## B. Review of Operations Procedures of NYISO

### *1. Standards and Compliance*

In New York, responsibilities for system operations are split between the NYISO and the individual Transmission Owners. Transmission Owners physically operate their individual electric systems, but do so at the direction of and in coordination with the NYISO for facilities, generally at voltages above 115kV. Transmission Owners generally operate those facilities at or below 115kV with little or no input from the NYISO (with some exceptions, of course). The split of operations responsibilities is defined in the NYISO-Transmission Owner Agreement.

Transmission system operations and maintenance are governed by standards developed by NERC, NPCC and NYSRC. Some standards used in New York are more stringent than NERC requirements. NPCC has a process to identify and sanction noncompliance through increasing levels of notification.

#### *a) Role of State Regulators Regarding Operators*

The NYPSC has established customer based reliability targets (with financial penalties if exceeded), which can be adversely affected by transmission outages. Additionally, the NYPSC has established penalty targets for the number of 115kV (as well as distribution and sub-transmission) momentary outages.

The NYPSC has established tariff rates, which include both distribution and transmission.
The NYPSC is actively involved in the review of all major and/or newsworthy events. For example, utilities are required to have emergency plans on file with NYPSC staff, and must submit post-event critiques for all major storms. The NYPSC serves as the arbitrator for any disputes that may arise between the NYISO and the NYSRC.

#### *b) Key Elements of Operations & Maintenance*

The elements of Operations and Maintenance ("O&M") in New York include:
- Forestry (Right-of-Way ("ROW") Management and Distribution Trimming);
- Preventive Maintenance (such as circuit breaker and relay maintenance);
- Corrective Maintenance (such as repairing a failed circuit breaker);

- Storm and Major Event Restoration;
- System Operation, including:
  - Monitoring the electric system and equipment;
  - Ensuring system security (thermal and voltage);
  - Switching and/or reconfiguring the electric system;
  - Monitoring generation;
  - Responding to alarms and dispatching crews; and,
  - Interface with the ISOs and adjacent Transmission Owners

The operating relationship between the Transmission Owners and the NYISO is defined in a contract known as the "ISO/TO Agreement" and in the NYISO Operating Manuals.

### *c) Vegetation Management Protocols For Transmission*

Vegetation management protocols for transmission are specified in a ROW Management Plan that is submitted by each Transmission Owner and approved by New York Department of Public Service ("NYDPS") staff. There is not a single, state-wide vegetation management protocol. However, the Transmission Owners and NYDPS forestry staffs maintain a significant dialog (including field visits) throughout the year, and the NYDPS forestry staff drives any desired similarity or specific compliance items among the New York utilities.

ROW management plans cover subjects and activities, including visual inspections, ROW floor maintenance, dangerous tree management, spot and emergency tree and vegetation trimming, storm restoration, and new construction clearing of ROW and work areas. Transmission Owners generally pursue an approach to ROW Management that includes selective clearing and herbicide use to encourage low growth and non-woody vegetation in the ROW.

### *d) Operator Training Standards*

There are no New York state-wide standards for training operators. The NYISO conducts voluntary training and review sessions for operators twice each year. Individual utilities are responsible for developing and implementing their own training standards and programs for their operators. While individual utilities are expected to comply with NERC requirements for the minimum requirements for operator training, these requirements are typically exceeded by each utility.

### *e) Maintenance Data for the Region*

There are no New York state-wide standards for collecting, utilizing or storing maintenance data. However, the NPCC has established certain standards for maintenance of bulk power equipment and maintenance and testing of relay equipment.

## C. Sources Used in Summary of NYISO Region

a. NYISO Comprehensive Planning Process for Reliability Needs – filed with FERC 8/20/04; pending review.
b. NY Independent System Operator Agreement.
c. NYISO Open Access Transmission Tariff.

d. NYISO 2003 Intermediate Area Transmission Review of the New York State Bulk Power Transmission System (Study Year 2008).
e. NYISO Planning Manuals entitled:
    1. Emergency Demand Response Program
    2. Day Ahead Demand Response Program
    3. Installed Capacity 5.1
    4. Load Forecasting
    5. Reliability Assessment and Enforcement
    6. System Analysis Data
    7. Transmission Expansion and Interconnection
f. NYISO Administrative Manual entitled Market Participant's Users Guide.
g. National Grid USA's Vice President, Network Operations.

# PJM Interconnection, L.L.C. (PJM)

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*(as of 11/19/04)*

## Overview of the PJM Region

PJM Interconnection, L.L.C. (PJM), became the first operational Independent System Operator (ISO) in the U.S. on January 1, 1998. Its objectives are to ensure the reliability of the bulk power system and to facilitate an open, competitive wholesale electric market. PJM initially was established in 1927 as a centrally dispatched control area that pooled the generation and transmission facilities of several utilities. Today, PJM is the largest centrally dispatched electric power system in North America and is a Federal Energy Regulatory Commission (FERC)—approved Regional Transmission Organization (RTO). PJM serves as the control area operator, transmission service provider, market administrator, regional transmission planner and NERC Reliability Coordinator for its region. As of October 1, 2004, PJM serves approximately 44 million people in all or parts of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM's region has over 134,000 megawatts (MW) of generating capacity, a peak demand of about 108,000 MW and approximately 610 million megawatt-hours (MWh) of energy sales. PJM's footprint has expanded significantly west and south in the last few years. The first major expansion occurred in April 2002 when the Allegheny Power System, comprised of three vertically integrated utilities serving portions of Pennsylvania, Maryland, West Virginia, Virginia and Ohio, became a member. The second major expansion occurred on May 1, 2004, when Commonwealth Edison, which serves Northern Illinois, became a member. On October 1, 2004, American Electric Power (a large multi-utility system that serves retail customers in several states, including Ohio, Indiana Kentucky and West Virginia) and Dayton Power & Light (which serves a portion of Ohio) became PJM's newest members. Two additional transmission-owning utilities, Dominion-Virginia Power and Duquesne Light, plan to join PJM in the near future.

## A. Review of Current Planning Process of PJM

### *1. Responsibility for Planning in the Region*

PJM staff annually prepares a Regional Transmission Expansion Plan (RTEP) to meet PJM Planning Criteria requirements for a reliable, economical, and environmentally acceptable high-voltage transmission system. Transmission Owners must construct transmission facility enhancements or upgrades specified in the RTEP, subject to siting requirements and regulatory approvals. The RTEP is subject to broad stakeholder input and must be approved by the PJM Board of Managers.

To ensure their neutrality, the PJM Board is comprised of ten members that have no personal affiliation or ongoing professional relationship with or any financial stake in any PJM market participant. The Board ensures that no member or group of members has undue influence over PJM's decision-making process. The Members Committee, on which each PJM member/customer has a representative, provides advice to the Board by proposing and voting on changes and new initiatives. The committee is com-

posed of five voting sectors representing (1) generators, (2) transmission owners, (3) electric distributors, (4) power marketers, and (5) end-use customers. A proposal needs to have the support of at least 67% of the full Members Committee, with support among each of the five sectors, to be forwarded to the Board as a recommendation.[12]

### *2. Regional Planning Process/Stakeholder Input*

The PJM planning process is driven by a number of planning perspectives and inputs, including the following:

- Mid-Atlantic Area Council (MAAC) Reliability Assessment
- East Central Area Reliability Council (ECAR) Assessment
- PJM Transmission Adequacy Assessment
- PJM Annual report on Operations
- PJM Load Serving Entity (LSE) resource plans
- Transmission Owner transmission development plans
- Independent Power Producer (IPP) capacity plans
- Merchant Transmission Developer plans
- Interregional transmission development plans
- Firm Transmission Service Requests
- PJM Transmission Expansion Advisory Committee (TEAC) input
- PJM Development of Economic Transmission Enhancements

The cumulative effect of these drivers is analyzed through the planning process to develop a single RTEP that recommends specific transmission facility enhancements and expansion. Each plan encompasses a set of recommended "direct connection" transmission enhancements, a set of "network" transmission enhancements and the cost responsibility of each party involved.

Input from all interested parties is considered under the planning process. The process includes broad stakeholder input through periodic meetings with the Transmission Expansion Advisory Committee (TEAC). TEAC is not a standing committee with set membership but is instead a vehicle for wide public participation in the PJM planning process. All stakeholder groups—including transmission owners, generators, state regulators, consumer advocates, and environmental groups—are allowed to send two representatives to TEAC meetings.

Stakeholder representatives sign up in advance to attend TEAC meetings, which usually involve about 80 people. PJM meets with TEAC four times a year to present its updated regional transmission expansion plan. The main purpose of these quarterly meetings is to get stakeholder feedback on the PJM plan. TEAC is an advisory committee; its members do not formally endorse the RTEP or specific projects in the plan and do not vote on any part of the Plan.[13]

TEAC meetings generally focus on the technical details of PJM's evolving transmission plan rather than on policy issues. Although information on all pending and recently completed projects is provided, PJM normally provides a fairly detailed review of only those projects where some special issue has arisen. Typically, this involves about 10-15 of the new generation and transmission projects under consideration. However, policy issues, such as the appropriate capacity credit for wind generators, occasionally are discussed at a TEAC meeting.

TEAC meetings also provide attendees an opportunity to offer alternatives (e.g., load management, dis-

tributed generation) to transmission projects included in the plan. PJM will respond to alternative proposals offered by an attendee at a TEAC meeting and, where necessary, will provide a quantitative analysis of the alternative.

PJM also may hold additional "informational' TEAC meetings throughout the year. The purpose of such meetings is to cover issues other than the regional plan, such as specific feasibility studies or tariff changes.

## *3. Specific Regional Practices*

PJM annually develops a RTEP to meet all of PJM's Planning Criteria including requirements for firm transmission service on its system. PJM plans on a region-wide basis and coordinates expansion plans across the systems of its transmission owners. The need for transmission enhancements is driven primarily by three non-exclusive factors: (1) maintaining compliance with reliability standards; (2) new generator interconnections; and (3) economic considerations, such as the reduction of chronic transmission congestion.[14] Figure 1 provides an overview of how these various elements are coordinated within PJM's planning process. Ensuring the reliability of the bulk-power grid has been the primary goal of PJM's transmission planning process and continues to be a critical goal today. However, economic considerations are becoming a more important factor in PJM's planning process, as explained below.

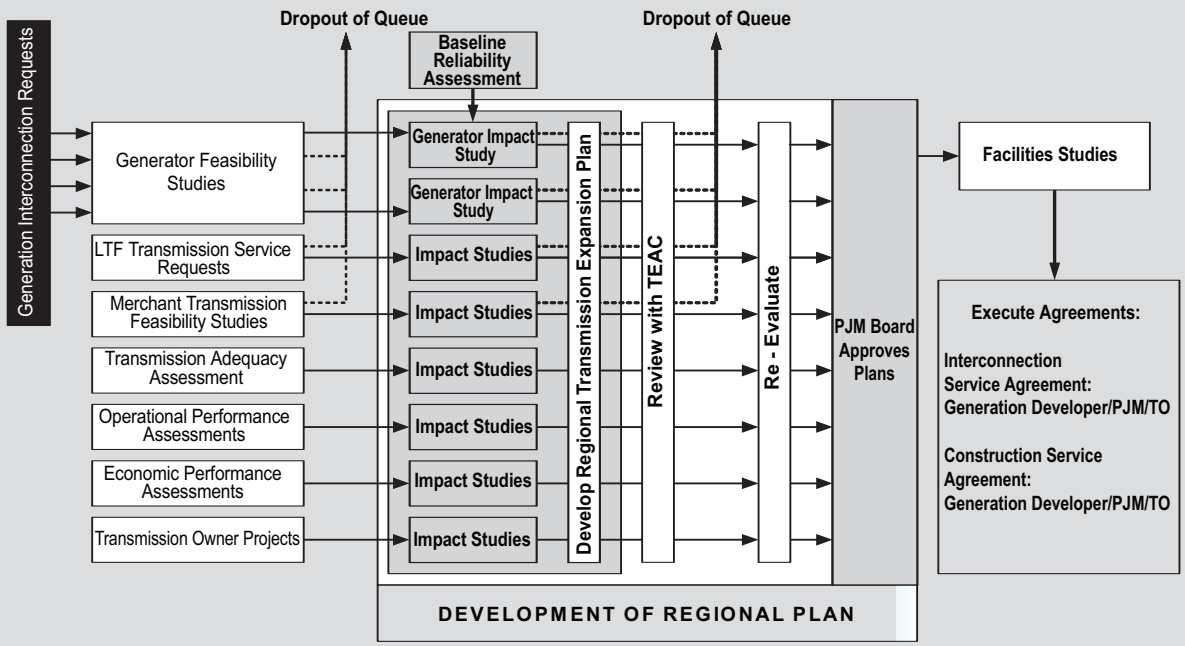
This section will review the distinct but related processes by which PJM develops transmission expansion proposals in response to reliability considerations, generator interconnections, and economic considerations.

### *a) Baseline Reliability Assessment*

In developing the RTEP, PJM establishes a starting point or "baseline" from which the need and responsibility for enhancements can be determined. The baseline assessment is performed for a five-year period, over which PJM performs a comprehensive load flow analysis of the ability of the PJM system to meet the single contingency, second contingency, and multiple facility outage contingency tests required by the MAAC or other appropriate reliability criteria.[15] In performing this assessment, PJM takes into accounts forecasted firm loads, firm imports and exports to neighboring systems, existing generation and transmission assets, and new generation and transmission assets expected to be online within the 5-year forecast period. Transmission Owners supply PJM with the necessary load forecast data and transmission system modeling data, including total load to be served from each substation and the amount of any interruptible loads included in the total load. PJM obtains data from generation owners on all generation resources located in their geographic footprint, including unit sizes, operating restrictions, and any must-run unit designations required for system reliability or contract reasons. PJM also solicits information useful to the preparation of the RTEP from members, transmission customers and other interested parties, including regulatory agencies and consumer advocates.

Upon completion of its studies and analyses, PJM prepares a recommended enhancement and expansion plan to address any areas found to be non-compliant with applicable Reliability Criteria and forwards the plan to TEAC for their review. The plan also includes recommendations for the assignment of costs. The cost of all upgrades deemed necessary by the baseline reliability assessment are rolled into the zonal (license plate) rates of PJM transmission owners. The cost of each baseline transmission network reinforcement is borne by transmission owners in proportion to their benefit. Where agreement

**Figure 1**
**PJM Regional Planning Process**




Source: PJM Planning Working Group Meeting, 11/12/02

on benefits cannot be reached, costs for network upgrades are allocated according to load-ratio share.

### *b) Generator Impact Studies*

PJM coordinates the planning process for the connection and operation of new generating units and oversees the construction of the required interconnection facilities. All new generating capacity that plans to interconnect and operate in parallel with the PJM transmission grid and participate in the PJM capacity and energy markets (and any existing generating unit that is increasing its output capability by more than 1 MW above that specified in its Interconnection Service Agreement) must submit an interconnection request to PJM. Generation resources that are smaller than 1 MW and which do not plan to participate in the PJM capacity and/or energy markets need only coordinate planning, construction and/or interconnection operation with the host Transmission Owner. There also are streamlined procedures for generators of less than 20 MW.

A new generator seeking to interconnect to the PJM grid must go through a 3-step analytical process consisting of a (1) Generator Interconnection Feasibility Study, (2) System Impact Study, and (3) Generation Interconnection Facilities Study. Each step imposes its own financial obligations on the requesting party and establishes PJM milestone responsibilities. The first step, the Generator Feasibility Study, requires the generator to submit a $10,000 deposit. PJM performs a preliminary, 30-day study that identifies the transmission upgrades, if any, that may be required to reliably integrate the new generator's output into the PJM system and the estimated cost and construction time of those upgrades. If the generator decides to continue the interconnection process it proceeds to step two—the System

Impact Study. To qualify for a System Impact Study, the generator must submit a $50,000 deposit and demonstrate that it has submitted applications for all necessary air permits. System Impact Studies are performed twice a year by PJM—commencing on May 1 for all requests received during the six-month period ending January 31 and commencing on November 1 for all requests received during the six-month period ending July 31. (The totality of generation interconnection request received by PJM in one of these six-month periods is referred to as a queue.) In general, System Impact Studies will be completed within 120 days of the date the study begins. The System Impact Study provides a thorough evaluation of the reliability impacts for new generation connecting to the PJM system as a capacity resource. The study reviews both direct connection requirements and network impacts associated with the interconnection of the new generation. The potential impacts of interconnecting the new generation with the PJM system is evaluated for compliance with various reliability criteria. This study identifies the transmission upgrades, if any, that would be required to reliably integrate the new generator's output into the PJM system and the estimated cost and construction time of those upgrades.

After reviewing the results of the System Impact Study, the applicant must decide whether or not to pursue the third and final study, the Generation Interconnection Facilities Study. This study requires the applicant to submit a deposit in the amount of $100,000 or the estimated amount of its Generation Interconnection Facilities Study cost responsibility for the first three months of work on such study, whichever is greater. The Generation Interconnection Facilities Study provides complete details of the requirements for interconnecting a new generation project to the PJM system. The study includes a general description of the new generation interconnection project, indicates any changes from the System Impact Study Report, describes the scope of both direct connection work and network upgrade work and sets a schedule of major project milestone dates. The Facilities Study Report also provides a detailed cost estimate and description of the facilities to be installed. In addition, PJM provides a non-binding estimate of the incremental Annual Revenue Rights (ARRs) that the generator would receive in return for the network upgrades it would be required to pay for.[16]

After the Generation Interconnection Facilities Study is completed, PJM prepares an Interconnection Service Agreement (ISA) to be executed by the applicant and any affected Transmission Owner(s). The ISA establishes the generator's maximum cost liability for transmission upgrades. The ISA also identifies the rights associated with the interconnection of the generator as either a capacity or energy-only resource and any operational responsibilities, restrictions or other limitations on which those rights depend. Once the generator signs the ISA, its capacity then is included in PJM's future baseline analyses as a new generating plant expected to be online during the forecast period.

PJM uses a "but for" standard in determining the allocation of network upgrade costs to new generators. Under this standard, a new generator pays for network upgrade costs that the PJM system would not have incurred "but for" the addition of the generator's capacity. This is equivalent to charging the generator with the long-run incremental cost that it imposes on the PJM grid. To reach this determination, PJM performs a "deliverability" analysis in the System Impact Study. This study evaluates how flows change on the PJM system when the proposed new generator is added to the existing set of generating plants (including new generating plants that have executed an ISA) and transmission assets. To perform this analysis, PJM adds the full output of the new generator, adjusted for its expected availability factor, and decreases all other generation in PJM so that total generation in PJM is held constant. For example, if the output of the new generator is 500 MW, then PJM will inject 500 MW at the proposed location of the new generator. If the new set of flows causes a violation of any reliability criteria, PJM determines whether the 5 percent of more of the flow on any limiting (overloaded) facility is caused by the new generating plant. If the new plant's output contributes to 5 percent or more of the flow on an overloaded facility, the new plant is then responsible for paying all or a portion of the network upgrade

needed to bring the PJM system back into compliance with all reliability criteria. The cost of the required new upgrades may be allocated to all new generating units in a queue or in a certain location that have a five percent or greater impact on the overloaded facility. Network upgrade costs are allocated to new generators in proportion to their relative impacts on overloaded facilities (capacity and shift factor).

Estimated cost responsibility for network upgrades are included in the ISA, the full amount of which the project developer must post as security. The developer remains responsible for the actual amount of his respective upgrade cost responsibility. Once upgrade costs are established for a specific generator, that generator is not assessed additional upgrade costs spurred by a later queue of generators. Moreover, if PJM subsequently determines that a later generation project benefits from a transmission enhancement spurred by an earlier generation project, that later project may be required to pay a portion of the upgrade cost. In other words, a new generation project ultimately may end up paying less than the upgrade cost set forth in its ISA if one or more future projects end up paying for a portion of the upgrade cost.

A similar process is used to determine the directly allocable upgrade cost, if any, associated with new long-term firm transmission service requests or with a merchant transmission proposal. Merchant transmission proposals, while posted in a separate listing from generator interconnection requests, are reviewed in a common queue with generator interconnection requests and the overall analytical process is similar.

### *c) Economic Upgrades*

This is a new element of PJM's transmission planning which is being added at the behest of the FERC. PJM initially proposed that economic upgrades (i.e., transmission upgrades not specifically needed to maintain compliance with MAAC Reliability Criteria) be market-driven; i.e., developed by market participants, such as merchant transmission developers or providers of load management services, in response to current and forecasted energy prices and price differences within the PJM region. FERC, however, determined that PJM should consider the need for economic upgrades in its planning process. As a result, PJM has been developing a process to identify and evaluate the need for economic upgrades to comply with FERC's directive. PJM has held monthly stakeholder meetings since the middle of 2003 to solicit feedback related to PJM's proposed economic planning process. PJM's proposed process for identifying and evaluating economic upgrades, described below has received FERC's approval subject to minor conditions which PJM addressed in its final compliance filing on November 17.[17]

Under its process PJM will monitor and identify chronic "unhedgeable congestion" that exceeds a threshold cost level.[18] This information—the location and cost of this congestion—will be posted on PJM's website and thus readily available to all market participants. Where the threshold is exceeded, PJM would prepare a preliminary cost/benefit analysis of mitigating the constraint through a network upgrade. Once PJM completes its preliminary cost/benefit analysis, a one-year "open season" would begin. This open season will provide a window for market participants to propose market-based solutions to mitigate the constraint, such as a merchant transmission line, load management, and distributed generation, among other possible solutions. In theory, market-based solutions would be financially attractive and forthcoming if parties thought that they could relieve congestion at a cost less than the cost of the congestion and less than PJM's estimated cost of the needed network upgrade. PJM will review the technical feasibility of any market-based solutions proposed during the one-year window. (PJM would not review the cost effectiveness of such proposals because the cost of such investments would not be recovered in FERC-regulated transmission rates.) During the one-year window, PJM will

perform a detailed cost/benefit analysis of mitigating the constraint. If no technically feasible market solution is proposed by the end of the window period and PJM's cost/benefit analysis finds that the congestion could be economically mitigated by transmission enhancements, PJM will direct the construction of new transmission.

PJM appears to have fairly wide latitude in determining how to allocate the costs of economic upgrades. In its cost/benefit analysis, PJM would publish initial results that would include "the market participants that would be the beneficiaries of, and therefore likely would be designated to bear responsibility for the costs or for payment of charges for recovery of the costs of such enhancement(s) or expansion(s), including a preliminary allocation of such costs among such market participants."[19] This suggests that economic upgrades could be assigned to specific customers, or a group of customers, much like certain upgrades are assigned to specific generation projects. However, PJM initially intends to allocate the costs of economic upgrades solely on a zonal (i.e., utility-specific) basis. When the load affected by the relevant congestion is located entirely in a single zone, that zone will be allocated 100 percent of the cost of the upgrade. When the affected load is located in more than one zone, PJM will allocate the cost of the transmission upgrade among the affected zones. Sub-zonal or even more discrete cost allocations may be used over time as PJM's analytical tools and settlement systems are refined.[20]

### *d) Interrelationship Among Planning Elements*

In summary, new transmission upgrades proposed by PJM are the result of three distinct but related processes: (1) the baseline reliability assessment; (2) generator (and merchant transmission) interconnection studies; and (3) cost/benefits analyses of mitigating chronic congestion. However, all new transmission investments, regardless of their underlying motivation, affect all aspects of PJM's subsequent transmission planning. For example, all new generation projects (and merchant transmission projects) that sign an ISA with PJM and the affected transmission owner(s) are included in subsequent baseline reliability assessments. Network upgrades or reinforcements resulting from the baseline plan are assumed in subsequent deliverability studies for new generation projects. The baseline plan also includes PJM's cost/benefit analyses for congestion-reducing investments. So there is a significant amount of interdependency in the various elements of PJM's planning process.

### *e) Cost Allocation and Cost Determination*

The cost of new upgrades built in the PJM regions are allocated according to a mix of traditional "rolled in" pricing and a form of participant funding. The full cost of baseline/reliability upgrades are rolled into the transmission rates of PJM transmission owners. However, the cost of a reliability upgrade won't always be allocated to the transmission owner that serves the area where the upgrade is located. The cost of a reliability upgrade is allocated to the transmission owner which benefits from the upgrade, even if the upgrade is not physically located within that transmission owner's service area.

As noted, new generators pay for upgrade costs that PJM deems would not be incurred "but for" the addition of the new generating plant to the PJM system. Upgrade costs directly allocated to one or more new generating plants are not rolled into regulated transmission rates. In return for bearing the cost of upgrades, new generators receive incremental ARRs. These incremental ARRs, broadly speaking, reflect the incremental transfer capability between two locations in the PJM system (a "source" and a "sink") resulting from the upgrade. The incremental ARRs allocated to a new generator stay the same for up to 30 years or the life of the project. The quantity of ARRs allocated to a specific generator cannot be reduced by future generation and transmission additions to the PJM system.[21]

It appears that the cost of economic upgrades will be rolled into the transmission rates of utilities serving load affected by the congestion, at least initially. However, PJM has latitude in regard to allocating these costs and may depart from zonal allocation in the future as its analytical tools become more refined. Since congestion often affects well-defined areas (i.e., load pockets), it is possible that PJM reasonably could determine that an economic upgrade benefits customers within a specific geographic area that may be smaller than (or overlap with) the boundaries of the local transmission owner(s).

Economic upgrades built by market participants, such as a merchant transmission line, will not be included in transmission rates. Where system transfer capability is enhanced, the project developer, much like a new generator, would receive incremental financial transmission rights for the life of his investment.

## B. Review of Operations Procedures of PJM

### *1. Standards and Compliance*

PJM is the regional security coordinator for the PJM RTO and is responsible for all regional security coordination as defined in the NERC Operating Manual and applicable PJM Operating Manuals.22 As security coordinator, PJM is responsible for real-time monitoring of system conditions (including voltage, frequency, transmission and generation availability, and power flows) in order to anticipate potential reliability problems, and for directing and coordinating relief procedures to respond to transmission loading problems (such as halting additional interchange transactions and implementing emergency procedures).[23] PJM operates the transmission grid in compliance with good utility practice, NERC, and PJM standards, policies, guidelines and operating procedures.

To receive the FERC's approval, a RTO must meet four essential characteristics and perform eight functions. These essential characteristics and functions were established by FERC in Order 2000, issued December 20, 1999. One essential characteristic is that the RTO have operational authority over all transmission facilities under its control. Another essential characteristic is that the RTO have exclusive authority for maintaining the short-term reliability of the transmission grid under its control. Hence, as a FERC-approved RTO, PJM has operational authority over the transmission facilities under its control and also has exclusive authority for maintaining day-to-day reliability in the PJM service area.

To demonstrate that it has exclusive authority over short-term reliability, a RTO must: (1) have exclusive authority for receiving, confirming, and implementing all interchange schedules; (2) have the right to order the redispatch of any generator connected to transmission facilities it operates if necessary for the reliable operation of those facilities; (3) have authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards; and (4) if the RTO operates under reliability standards established by another entity (e.g., a regional reliability council), the RTO must report to the Commission if these standards hinder its ability to provide reliable, non-discriminatory and efficiently priced transmission service. In its July 12, 2001 order granting RTO status to PJM, FERC found that PJM had the requisite authority to perform these reliability-related functions.

PJM's operation of transmission facilities is governed by NERC Operating Guidelines as implemented by the regional reliability councils. These guidelines require PJM to consider transmission constraints, restrictions and/or limitations in the overall operation of the PJM RTO. The PJM RTO is operated such

that the following limits are not violated: (1) thermal facility limits; (2) voltage limits; (3) transfer limits; and (4) stability limits.

Transmission owners must operate their transmission facilities in accordance with the PJM Operating Manuals and follow PJM instructions related to PJM responsibilities, including but not limited to: (1) performing the physical operation and maintenance of their transmission facilities; (2) directing changes in the operation of transmission voltage control equipment; and (3) when necessary, taking the additional actions required to prevent an imminent emergency condition or to restore the PJM transmission grid to a secure state in the event of a PJM system emergency. Transmission owners are subject to numerous responsibilities and obligations under the PJM Transmission Owners Agreement (as well as a code of conduct). For example, transmission owners must establish the ratings of their transmission facilities and provide these ratings to PJM. In addition, PJM transmission owners must operate and maintain their transmission facilities in accordance with good utility practice and PJM procedures and standards. PJM transmission owners also must plan and coordinate transmission system outages with other transmission owners as required. Facility outage requests must be submitted to PJM in accordance with PJM requirements.

## C. Sources Used in Summary of PJM Region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b. Regional Planning Process: PJM 101, the basics.
c. Email from Jim Glennon, PJM, to Greg Basheda, December 18, 2003.
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e. www.pjm.com/about/independence.html.
f. 2002 Baseline RTEP Report (For the 2003-2007 Period), March 19, 2003.
g. PJM Open Access Transmission Tariff, Schedule 6: Regional Transmission Expansion Planning Protocol. Third Revised Rate Schedule FERC No. 24. Original Sheet No. 182. Effective March 20, 2003.
h. PJM Open Access Transmission Tariff, Schedule 12: Transmission Enhancement Charges. Sixth Revised Volume No. 1. First Revised Sheet No. 270A. Effective July 24, 2003.
i. PJM Reliability Planning Criteria.
j. Miscellaneous Portions of PJM's Open Access Transmission Tariff: Original Sheet No. 37, 39, 105-108.
k. PJM Compliance Filing, March 20, 2003, FERC Docket No. RT01-2-000.
l. Order on Rehearing and Compliance Filings, 109 FERC ¶ 61,067 (Oct. 18, 2004).
m. PJM Compliance Filing, April 21, 2004, FERC Docket No. RT01-2-014.
n. FERC Order on Rehearing and Compliance Filing and on Tariff Filing, Docket No. RT-01-2-005, et al. July 24, 2003.
o. FERC Order Granting PJM RTO Status, Granting in Part and Denying in Part Requests for Rehearing, Accepting and Directing Compliance Filing, and Denying Motion for Stay, Docket Nos. RT01-2-001 and RT01-2-002, December 20, 2002.
p. Transmission Expansion Advisory Committee Meeting, February 26, 2003.
q. PJM Compliance Filing, August 25, 2003, FERC Docket No. RT01-2-010.
r. FERC Order on Rehearing and Compliance Filing Regarding Transmission Expansion Projects Needed to Promote Competition, Docket Nos. RT01-2-009, RT01-2-010, and ER03-738-001, October 24, 2003.
s. PJM Compliance Filing, November 24, 2003, FERC Docket No. RT01-2-012.
t. PJM Manual 3: Transmission Operations. Effective Date: January 13, 2004.

u. FERC Order No. 2000 (Regional Transmission Organizations), Docket No. RM99-2-000, December 20, 1999.
v. Transmission Expansion Advisory Committee Meeting, February 26, 2003.
w. PJM Compliance Filing, August 25, 2003, FERC Docket No. RT01-2-010.
x. FERC Order on Rehearing and Compliance Filing Regarding Transmission Expansion Projects Needed to Promote Competition, Docket Nos. RT01-2-009, RT01-2-010, and ER03-738-001, October 24, 2003.
y. PJM Compliance Filing, November 24, 2003, FERC Docket No. RT01-2-012.
z. PJM Manual 3: Transmission Operations. Effective Date: January 13, 2004.
aa. FERC Order No. 2000 (Regional Transmission Organizations), Docket No. RM99-2-000, December 20, 1999.

# Southeastern Electric Reliability Council (SERC)

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*(as of 11/18/04)*

## Overview of the Southeastern Electric Reliability Council (SERC)

The Southeastern Electric Reliability Council (SERC) is the largest NERC Region as measured by total generation and total load. The SERC Region covers an area of approximately 464,000 square miles and includes parts or all of thirteen southeastern and south central states. SERC is divided geographically into four diverse sub-regions – Entergy (the geographical areas of Entergy Operating Companies and Associated Electric Cooperative, Inc.), Southern (the geographical areas of the Southern Operating Companies, Alabama Electric Cooperative, South Mississippi Electric Power Association, SE Power Administration, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and City of Dalton), TVA (the Tennessee Valley Authority area) and VACAR (the Virginia-Carolina areas including Progress Energy Carolinas, Dominion Virginia Power, Duke Power Company, South Carolina Electric and Gas Company, North Carolina Electric Membership Cooperation, Old Dominion Electric Cooperative, Alcoa Power Generating Company Inc., Fayetteville Public Works Commission, North Carolina Eastern Municipal Power Agency, and South Carolina Public Service Authority). SERC's membership of 39 regular members and 14 associate members include investor-owned utilities, cooperative utilities, municipal utilities, federal and state power systems, independent power producers, and power marketers.

## A. Review of Current Planning Process of SERC

### *1. Responsibility for Planning in the Region*

Since the SERC Region is so large, the SERC member system staffs conduct the necessary analyses of the transmission systems and propose enhancements to facilitate the regional planning process within their system, coordinate planning activities with other entities within the region, and perform joint planning, as required, to ensure that the defined transmission adequacy criteria are met. The SERC staff does not perform any regional planning studies or analysis or publish a regional report with all the proposed transmission enhancements. The SERC member systems perform next season assessments from an operational perspective, assessments for budget purposes for the next five years, and assessments for up to 10 years out for forecasting of potential transmission projects within the sub-regions of SERC. These assessments are presented to the appropriate owning entity for the final decision process to determine which facilities or options are to be implemented.

Reliability Agreements among SERC member systems require that joint transmission planning assessments are conducted and other coordinated planning activities are performed through participation in reliability groups. SERC member systems participate in the following reliability groups included but not limited to:

VACAR-AEP-SOUTHERN-TVA-ENTERGY
VACAR
VACAR-SOUTHERN-TVA-ENTERGY
SOUTHERN-TVA
VACAR-SOUTHERN
VACAR-TVA
SOUTHERN-ENTERGY
ENTERGY-TVA
VACAR-ECAR-MAAC
MAIN - ECAR-TVA
MAIN - TASG
MAIN - FSSG
MAAP-MAIN-SPP
SOUTHERN–FRCC
ENTERGY-SPP
ENTERGY-MAPP
ENTERGY-MAIN

The results of the assessments conducted by these groups are thoroughly and regularly reviewed by SERC. If these assessments determine that enhancements are required, then the impacted entity uses their internal process for processing the enhancements.

### *2. Regional Planning Process/Stakeholder Input*

The stakeholders included in this process are the transmission owning entities; these are customers that request firm transmission service and appropriate regulatory bodies. The involvement of these stakeholder groups varies across the different sub-regions but their inputs and concerns are considered in all sub-regions. SERC does not have a structure where the stakeholders have a vote to determine which projects are constructed. Instead, the transmission owners consider all requests for firm transmission services from their stakeholders and then, using the NERC Planning Standards and additional more stringent regional and individual planning requirements, determine if their system is adequate and reliable to meet all firm transmission service requests. If this annual analysis indicates that new or upgraded transmission facilities are required to ensure an adequate and reliable transmission system, then the responsible transmission owner evaluates options and decides what is the appropriate enhancement or option to pursue. If needs are discovered during this analysis, the transmission entity where the enhancement is required plans for, designs and ensures that the required enhancements are constructed in a timely manner. Upon completion, the enhancement is owned by the transmission entity and the owner becomes responsible for the maintenance and repair of the facility for its useful life. In most instances some form of cost allocation is made between the wholesale and retail classes of customers for the transmission enhancements completed.

### *3. Specific Regional Practices*

The SERC Region does not have a standard policy for the treatment of non-wire type solutions; however, the transmission owners consider options in determining the best possible solution for a transmission

need. For example, the Southern Company has customers with interruptible power supply contracts and, if the use of one of these contracts can defer the need for transmission upgrades for a period of time, then this is one of the options considered. Dispersed generation is another non-wires type solution considered when the opportunity is presented.

NERC Planning Standards and SERC Supplements are the foundation documents used within SERC for performing studies. SERC member systems may impose additional requirements on their respective transmission system planning evaluations. SERC member systems comply with NERC Planning Standards Table IA and SERC Supplements IA, IE1, IE2 and IID. (SERC Supplements to the NERC Planning Standards may be found on the SERC website at: http://www.serc1.org/Pages/DocumentSearch.aspx?FN=SERC%20Supplements/Planning). Most SERC member systems study and plan for a contingency criteria greater than n-1 when planning their respective transmission systems. Additional criteria are created and approved by the regional member system for their respective transmission system and documented in the annual FERC Form 715 filing.

Key factors considered by the system members in making these analyses are as follows: load forecast, resource expansion plans, and signed agreements for firm transmission service. Base cases are made available to the stakeholders via the individual companies OASIS website or the SERC website. A stakeholder may request these cases and, after paying an administrative fee, be provided the base cases used by the transmission owning entity for evaluating their transmission system. Using these base cases, in conjunction with resource and transmission expansion plans, stakeholders have access to the proposed plans for a transmission entity.

SERC member systems comply with the NERC Planning Standards and SERC Supplements. Compliance is assessed annually by self-certification as part of the SERC Compliance Program and by on-site audits scheduled every three years. The individual systems also perform annual reviews of their respective systems to ensure compliance with their individual system criteria. Currently no monetary or contractual obligations are imposed by SERC for non-compliance; however, non-monetary sanctions such as peer pressures are imposed if an entity fails to make appropriate system enhancements and a neighboring entity anticipates transmission impacts on its system.

The involvement of local, state, and federal regulators varies across the region due to jurisdictional responsibilities. Not all transmission owners fall under a local, state or federal regulator and each regulator approaches the regulatory process differently. For those that are regulated, once a need and corresponding solution has been identified the appropriate regulator is included in the process.

A summary of several of the state's planning and siting responsibilities is provided below.

### *Alabama*

The Alabama Public Service Commission (APSC) has legislative jurisdiction over the construction of plant, property, and/or facilities for the production, transmission and/or delivery of gas, electricity, water, or steam by a public utility, except for the normal and ordinary extensions of existing systems. The public utility is required to make a written application to the Commission for a Certificate of Public Convenience and Necessity and, after a public hearing; the Commission may or may not, at its discretion, issue the Certificate to the public utility.

The APSC does not have formal requirements or authority regarding the siting or planning of generation and transmission facilities. In addition, the APSC does not have any formal Integrated Resource Plan fil-

ing requirements for electric and gas utilities. However, the IRP process has been recognized and accepted by the Commission as a prudent means of identifying necessary and appropriate additions of electric generating capacity. On an informal basis, this information is presented to the Commission staff for informational purposes only. The Commission has also adopted Request for Proposal (RFP) Guidelines to be followed by the public utility seeking to build new electric generating capacity.

### *Arkansas*

The Arkansas Public Service Commission requires public utilities to obtain a Certificate of Public Convenience and Necessity for the construction or operation of any new equipment or facilities for supplying a public service. Public utilities are also required to obtain a Certificate of Environmental Compatibility and Public Need for the construction of a major utility facility.

### *Florida*

Florida has both power plant and transmission line siting legislation. For power plants with a steam capability of greater than 75 MW, an applicant must obtain a Determination of Need from the Florida Public Service Commission (FPSC). The same is true for transmission lines that are 230 kV or greater, cross a county line, and are greater than 15 miles in length. Both the transmission and power plant siting laws require approval from the Florida Department of Environmental Protection and ultimately, the Governor and Cabinet issue the final certification. In this manner, the laws of Florida seek courses of action that will fully balance the increasing demands for electrical power plant/transmission line location and operation with the broad interests of the public.

Florida also requires certain utilities to file Ten-Year Site Plans that include both generation and transmission planned additions. While not a formal integrated resource plan, the FPSC reviews this information annually and reports to the DEP for use in future siting proceedings. In addition, local water management districts comment on the proposed plans.

### *Georgia*

The Georgia Public Service Commission (GPSC) has authority under the Integrated Resource Planning (IRP) Act to approve an Integrated Resource Plan for the investor-owned utilities in the state (Georgia Power and Savannah Electric & Power Companies) and to certify certain capacity additions used to serve retail load. The GPSC does not have jurisdiction over siting of transmission facilities — just approval of costs associated with the portion of transmission facilities that are allocated to serve retail load which are recovered through base rates.

The GPSC has no specific requirements for siting and construction of transmission lines. Utilities are encouraged to work with the Georgia Department of Transportation to ensure that lines conform to road and highway specifications. Other state agencies such as the Georgia Department of Natural Resources may also have certain jurisdiction if construction involves a river or wetland crossing. A state law passed in 2004 increases the requirements on all electric utilities in Georgia for transmission lines that require the use of eminent domain and are at least115 kV and over one mile in length.

### *Kentucky*

All electric transmission lines require a Certificate of Public Convenience and Necessity from the Kentucky Public Service Commission. Utilities that operate under the jurisdiction of the Commission

must obtain Commission approval before they begin to construct any generating facilities or major transmission facilities, particularly those needed to tie generation into the existing transmission grid. The approval process consists of two separate and distinct analyses arising under different statutory provisions.

One analysis, arising under KRS 278.020(1), requires the Commission to grant a certificate of public convenience and necessity before the proposed facilities are constructed. This analysis examines the extent to which a utility's existing facilities are or will soon be inadequate to provide reasonable service to current or future customers. If an inadequacy exists; the proposed facilities are then examined to ensure that they will not result in any wasteful duplication. In addition, if the proposed facilities include a new transmission line that will operate at 400 kilovolts ("kV") or higher, KRS 278.027 requires consideration of the route of that line. Specifically, the Commission cannot grant a certificate of public convenience and necessity for a 400 kV or higher transmission line unless it finds that the proposed route "will reasonably minimize adverse impact on the scenic and environmental assets of the general area concerned, consistent with engineering and other technical and economic factors."

The other analysis, arising under KRS 278.025, requires the Commission to determine whether the utility should be granted a certificate of environmental compatibility to construct facilities to be used for the generation of electricity. This analysis examines the environmental impacts of the proposed facilities and requires any adverse impacts to be balanced against the community needs, industrial development, customer requirements, and the economics of the facilities.

### *Louisiana*

The State of Louisiana does not have any legislative requirements concerning the certification of electric generation and transmission facilities or integrated resource planning. Approvals for the construction of such facilities are subject to local zoning and the normal state and federal environmental permits. For example, the Louisiana Department of Environmental Quality issues air permits for new generation facilities based on federal standards.

In September 1983, the Louisiana Public Service Commission (LPSC) adopted a General Order requiring the certification of new capacity resources. A Louisiana utility must obtain a certificate of public convenience and necessity (CPCN) from the Commission prior to commencing construction or entering in to a purchase power contract. (This does not apply to economy energy or emergency power purchases.) Under the General Order, the Commission shall rule on a CPCN application within 120 days, and the utility must provide justification for the proposed resource acquisition along with the supporting cost data.

The LPSC recently completed a rulemaking docket which supplements and modifies the 1983 General Order (Docket No. R-26172). The approved Rule requires the use of a market-based mechanism (such as a formal RFP process) whenever a Louisiana electric utility seeks to construct or acquire new generation resources, above certain size thresholds. This Rule requires the RFP solicitation process and project review to be conducted subject to Staff oversight and consultation.

The LPSC does not have a formal integrated resource planning process or detailed filing requirements. Bulk power supply planning issues are reviewed at various times in rate cases, certification cases (pursuant to the 1983 General Order), fuel clause reviews and other special proceedings.

At the present time, the LPSC does not have formal requirements regarding transmission planning or

certification. However, the Commission recently initiated a transmission certification rulemaking proceeding, and depending on the outcome of that proceeding, may adopt a certification requirement for new transmission investments (Docket No. R-26018). Energy Louisiana, Inc., in cooperation with Staff, recently completed a major cost/benefit study of transmission expansion investments. (Docket No. U-23356, Subdocket A)

### *Mississippi*

The Mississippi Public Service Commission issues a Certificate of Public Convenience and Necessity authorizing the construction of electric facilities, which Mississippi courts had previously determined as a prerequisite to the utility's right of eminent domain. Other state or federal agencies may require separate permits for transmission lines. For example, if a natural feature such as a river is crossed, the utility must contact the appropriate state or federal agency.

Under Mississippi law, the PSC has siting authority for any generation unit or transmission addition regardless of ownership. The siting must be in the public interest.

Permitting requirements of other federal, state and local entities must be met as well. Once the certificate of public convenience and necessity is granted the PSC has no other authority for wholesale units. Obviously, there is full authority for retail units and the planning thereof. Merchant plant certificates have been granted expeditiously. Several months, more or less, has been required to complete the filing and hearing process. The PSC also has the authority to approve or deny the transfer of assets as might be required in the establishment of Transcos or RTOs or in the case of mergers or sales.

### *North Carolina*

Under North Carolina law, any public utility or other person proposing to construct an electric generating facility must first obtain from the North Carolina Utilities Commission a certificate that the public convenience and necessity requires, or will require, such construction. Notice of an application is provided to the public, and a hearing is commenced within three months of the date of the application. A decision must be issued within 90 days after the conclusion of the hearing. By Commission rule, certain information must be filed 120 or more days before the filing of an application for facilities with a capacity of at least 300 megawatts and which are proposed to be constructed by a public utility.

This certification requirement does not apply to persons who construct an electric generating facility primarily for their own use; however, any such proposed construction must nevertheless be reported to the Commission. In addition, any person proposing to construct an electric generating facility must apply to the North Carolina Department of Environment and Natural Resources (DENR) for the appropriate air and water permits and must comply with local zoning ordinances.

In addition, no one may begin construction of a new electric transmission line in North Carolina without first obtaining from the Utilities Commission a certificate of environmental compatibility and public convenience and necessity. A transmission line is defined as an electric line designed with a capacity of at least 161 kilovolts. Notice of an application is provided to the public, and a hearing is scheduled (subject to cancellation if no significant protest is received) within four months of the date of the application. A decision must generally be issued within 60 days after the conclusion of the hearing. Copies of an application to construct either an electric generating facility or a transmission line are distributed through the North Carolina State Clearinghouse to the permitting divisions of DENR as well as other state agencies (such as the Historic Preservation Office, the Department of Agriculture, and the

Department of Transportation) and the relevant county clearinghouse. The information returned to the Utilities Commission through the Clearinghouse includes comments from these non-permitting agencies and further information from the permitting agencies on whether all permits have been identified by the applicant.

The Utilities Commission reviews the public utilities' plans for construction of generation and transmission annually through the integrated resource planning (IRP) process. Investor-owned utilities and the state-wide electric cooperative are required to file annual reports on September 1 of each year including forecasts of load and generation resources to meet the load, transmission planning, and certain other information. Comments on the utilities' IRP plans are received from interested parties and a hearing is held to receive testimony from public witnesses.

### *South Carolina*

The Public Service Commission of South Carolina is responsible for issuing a Certificate of Environmental Compatibility and Public Convenience and Necessity for electric transmission lines greater or less than 125 kV. An application to the South Carolina Public Service Commission should include a description of the facility and its location; summary of any environmental impact studies; a statement explaining the need for the facility; and such other information that the applicant considers relevant or that the Commission may require.

Within 60 to 90 days of receipt of the application by the Commission, a public hearing must commence. Before granting a Certificate, the Commission must determine the basis of the need for the facility and determine the nature of the probable environmental impact. The Commission must also determine whether the environmental impact is warranted, considering current technology and alternatives; whether the facility will serve the interests of system economy and reliability; and whether convenience and necessity requires the construction of the facility. The applicant must also provide reasonable assurance that the facility will conform to applicable state and local laws and regulations.

### *Tennessee*

The Tennessee Valley Authority (TVA) serves as the clearinghouse for electric transmission line siting. Siting follows guidelines based on the National Environmental Protection Act and any other pertinent national environ-mental laws. TVA solicits appropriate input from state agencies when considering a new line.

### *Virginia*

The Virginia State Corporation Commission issues Certificates of Public Convenience and Necessity for lines that meet criteria. In exercising its authority the Commission may permit the construction and operation of electrical generating facilities, which shall not be included in the rate base of any regulated utility, upon a finding that such generating facility and associated facilities including transmission lines and equipment (i) will have no material adverse effect upon the rates paid by customers of any regulated public utility in the Commonwealth; (ii) will have no material adverse effect upon reliability of electric service provided by any such regulated public utility; and (iii) are not otherwise contrary to the public interest. In review of its petition for a certificate to construct and operate a generating facility described in this subsection, the Commission shall give consideration to the effect of the facility and associated facilities, including transmission lines and equipment, on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact.

The pricing of transmission service within the SERC Region is based on tariffs filed with the FERC by the individual transmission service providers. SERC does not have a regional transmission rate due to the number of states involved and the size of the territory included within the region.

## B. Review of Operations Procedures of SERC

### *1. Standards and Compliance*

The majority of the SERC member systems utilize a state estimator program for studying transmission and generation outage / maintenance. For seasonal or extended timeframe analysis (operational planning) a multi-system load flow will be utilized for evaluating system outages. The following guidelines are generally used for scheduling transmission outages:

- The Reliability Coordinator will initiate a weekly transmission call to identify all 230 kV and 500 kV outages, including hot line work, and all 115 kV and 161 kV tie-line outages. Additionally, any other internal line outages that result in decreased generating capability or reduced tie-line capability should be communicated as well as any lower voltage lines considered regionally important.
- All lines at any voltage level determined to be Open Access Same Time Information System ("OASIS") critical or shown to affect transfer capability should be evaluated. This information must be maintained for accuracy in the near-term and will be considered the authority if conflicting dates are found.
- Planned outages should be identified and scheduled as far in advance as possible. OASIS critical lines or elements should be scheduled a minimum of one week in advance. This does not preclude scheduling either emergency or routine work with shorter notice on a direct contact basis by mutual agreement.
- Operating organizations perform a 13 Month transfer analysis to facilitate long-range OASIS postings. Any known long-range outages planned over the upcoming 13 months should be included in these long-range OASIS transfer studies. While experience has shown that transmission outage schedules made as far as 13 months in advance are estimates and should be expected to change, every effort is made with regards to coordination of network outage requests and accurate evaluation of transmission service requests. In accommodating outage requests and approving transmission service, priority will be given to the outage requests with the earliest notification with consideration given for the least economic impact.
- Each SERC sub-region's Reliability Coordinator initiates a conference call weekly with all sub-region members to capture outage requests. These outages are evaluated by the Reliability Coordinator to ensure sub-region reliability is not compromised.
- The outages that are scheduled for 100kV and above transmission facilities are shared by posting the information on a database maintained by the region. The database is accessible by transmission organizations that have signed a regional confidentiality agreement. This database allows regional evaluations to be performed utilizing current system configurations to ensure regional reliability is not compromised.

Each SERC sub-region's Reliability Coordinator updates the system data exchange (SDX) once each day to reflect the 100kV and above outages. The database is utilized to populate the eastern interconnection model, for determining the reliability of the interconnection, and, to curtail transmission system usage under transmission loading relief (TLR) procedures that may be initiated by a Reliability Coordinator. The region follows the NERC standards, however; this regional database exceeds NERC requirements.

The responsibility for operations and maintenance of transmission facilities is defined and is associated with ownership. Coordination is achieved within the operating companies by accumulating the individual outage requests, evaluating the requests as outlined in the above described method and scheduling the outages to meet NERC defined reliability requirements. A sub-region's request is processed in a similar manner to encourage communications while ensuring proper maintenance is achieved within NERC reliability requirements. The sub-region information is supplied to the region to ensure proper coordination, communication and to permit regional evaluation.

Responsibilities are shared with the member systems, aggregated by the each SERC reliability coordinator for subregional input, delivered to the region for regional evaluation, and finally rolled up to the eastern interconnect for assimilation into an overall model.

Retail or wholesale consumers are not normally involved in setting SERC standards since these standards are designed to prevent customer interruptions. In rare instances where maintenance will necessarily result in customer interruptions the customers will be notified.

NERC requirements define good utility operational behavior and provide guidance in maintaining reliability. SERC does not impose monetary penalties for failure to meet their requirements since non-compliance results in reliability margins that are unacceptable to customers, SERC members and regulators. The SERC Regional philosophy regarding operator training is that each operator must be adequately and effectively trained to perform their roles and responsibilities. For example, the Southern Company training program includes:

- Adequate time for training
- Good training material
- Use of drills and training exercises
- One dedicated instructor plus subject matter experts
- Good documentation.

Southern Company covers its operations schedule with six rotating shifts. (Four shifts are necessary to cover operations. One additional shift allows for relief and a sixth allows for training.) For each 6-week rotation of operators, five eight-hour days are allocated to training. This schedule provides approximately 340 hours per year for training with additional potential time during the relief shift.

Southern is instituting individual development plans, including course titles as well as course numbers, for each operator with yearly training goals. An individual's salary increase is tied to meeting these goals.

An Initial Training Course (ITC) is designed for new operators. Basically, it includes a one-week orientation to the Bulk Power Operations Department, an overview of the EMS, a three-day NERC Pre-certification course, and 8-12 weeks of on-the-job training. After this, the operator is scheduled to work the desk. This training is scheduled as needed, driven by vacancies. One of the end results of successful completion of this course is NERC Certification.

An Extended Training Course is offered to operators who have completed the ITC. It includes advanced levels and special courses. Typical Extended Course offerings (spring and fall seasons) include Power System Elements, Steady State Operation, and the Interconnected System, along with company specific topics such as Local Operating Procedures, Transmission Loading Relief procedures, System Security, and others.

Continuing Education Seminars and Drills involve regularly scheduled activities of a reiterative nature. They are designed to maintain and extend the knowledge and skills of coordinators and to enhance emergency preparedness. They consist of three-day seminars sponsored by SERC and others and include Emergency Preparedness Drills, material on system alerts and restoration, and other topics as well. Two annual drills (one in the spring prior to the summer peak and the other in the fall prior to the winter peak) are included as a part of the annual training programs for the Southern Control Area operators.

Southern has one trainer dedicated to Control Area and Security Coordination Training, other company trainers and Subject Matter Expert trainers. They also use outside training resources, such as those provided by SERC. Southern uses instructed training courses, self help courses, and drills to complete the training for existing staff.

The Southern Power Coordination Center provides and monitors the technical training that the operators receive. Non-technical training is provided and monitored by Human Recourses.

A three-step process is used to determine when a trainee is ready to perform shift responsibilities. First, the trainees must complete the training program. This is demonstrated by completion of the requirements listed on a series of check-off sheets for each position. The trainee is paired up with an experienced operator at each position. The completion of the check-off boxes is verified by demonstration to the operator with whom they are assigned. Associated with task assignments are homework on procedures and quizzes on the procedure review. As they complete these requirements, the Southern Training Coordinator interviews them. After all checks are completed, the operator demonstrates to the Training Coordinator his knowledge of all items. Finally, the operator must complete a verification interview with the Training Coordinator, the supervisor of the area, and other management or position experts. The final interview includes demonstration of subject matter and operational knowledge. The operator also must pass the NERC Certification Test. The Code of Conduct is reviewed annually.

Southern has a document titled "Power Coordination Center Training Program." In the Overview section of this document, it states on page 1 of 6, "Power Coordination Center Training includes instructor-led class work, self-study, site visits and operational exercises and simulation training. Training includes NERC and SERC policies and procedures." Outside training opportunities are discussed, as well as training for the use of new tools. Finally, the reference is made to FERC regulatory requirements, system reliability, and the economics of the competitive market requiring "a highly skilled operator and the necessity for a training program to address the complexities of the business."

Southern Company purchased a simulator in May of 2004 to use for Black start and restoration drills in addition to current operator training.

The Southern Company's Vegetation Management protocols as filed with the FERC in June 2004 are attached to this document to demonstrate one Company's vegetation management program. Other company's vegetation management programs can be obtained from the FERC as required.

The SERC Region does have a common definition of O&M expenditures however the Southern Companies and those entities regulated by the FERC are required to maintain its books and records regarding Operation and Maintenance Expenses per the Federal Energy Regulatory Commission's Uniform System of Accounts. The accounting requirements for labor, material, and expenses are in accordance with the Code of Federal Regulations, Title 18, Part 101. A copy of this is attached for your reference.

The SERC Region does not maintain planned and unplanned transmission facility maintenance outage data on a regional basis; however, each transmission owning entity maintains such information internally. The SERC Region maintains a repository on its website for its membership to post planned maintenance outages. This information is posted for coordination of outages among neighboring system within SERC.

## C. Sources Used in Summary of SERC Region

a. NERC 2002 Annual Report.
b. NERC's RTATF Summary Report for the SERC Region dated March 12, 2004.
c. SERC Website (www.serc1.org).
d. Interviews with various SERC Member System's Transmission Planning and Operations functions.
e. Southeastern Infrastructure Assessment report prepared by The Southeastern Association of Regulatory Commissioners dated May 8, 2002.
f. Southern Companies Control Area (SOCO) NERC Control Area Readiness Audit dated March 23 to 25, 2004.

# Southwest Power Pool (SPP)

*Prepared by: Nick Akins, American Electric Power*
*(as of 6/9/04)*

## A. Review of Current Planning Process of SPP

### *1. Responsibility for Planning in the Region*

SPP, located in Little Rock, Arkansas, has the responsibility for the regional planning of the transmission system within its footprint. Details of the regional planning process can be found at the following on SPP's website: http://www.spp.org.

The composition of the stakeholder groups is not prescribed. Basically, anyone with a legitimate business interest in the process may participate. The SPP stakeholder process is flexible and accommodating to stakeholder participants. If an entity feels that something is missing from the regional planning process or the stakeholder feedback process, that entity may express their concerns, air their differences, suggest alternative solutions, or process modifications at any time through a public Regional Planning Summit meeting periodically facilitated by the SPP. Information that is confidential or critical to national security is accessible through a secure website once a legitimate business need to obtain the information is demonstrated.

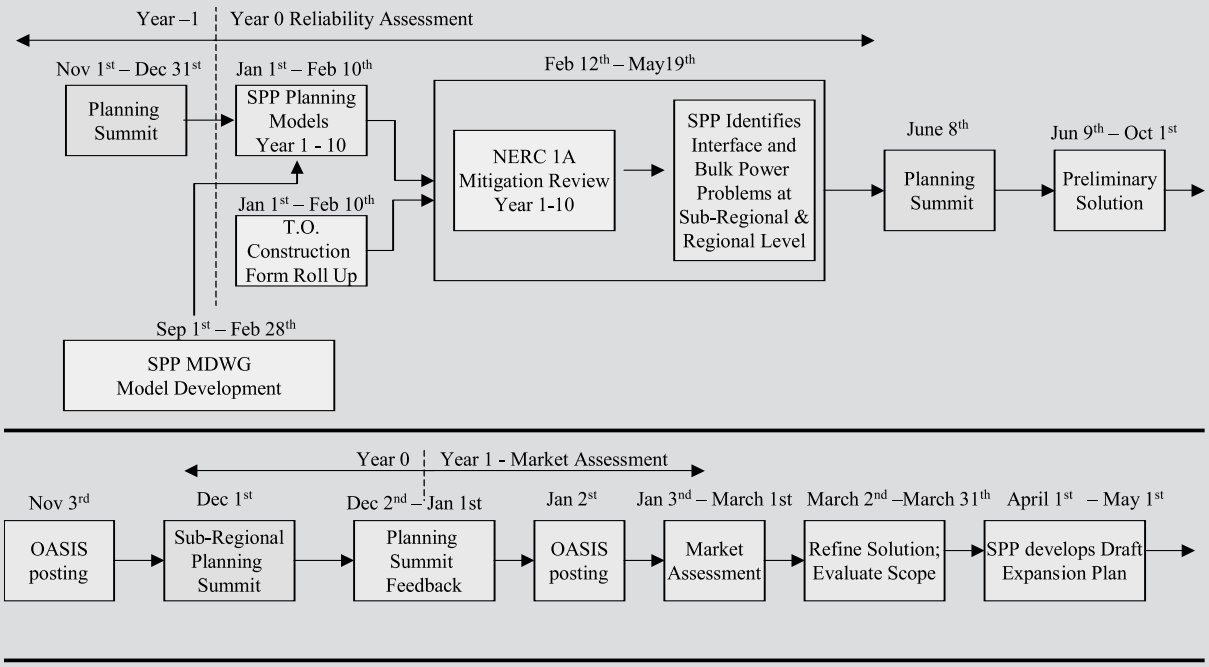
### *2. Regional Planning Process/Stakeholder Input*

The SPP regional planning process is summarized by the Gantt chart shown in Figure 1. Stakeholders have the opportunity for feedback through several mechanisms. SPP targets communications to stakeholder-designated contacts. The designated contacts are responsible for providing input for each stakeholder. Study participants must have a designated contact. Contacts will be notified of study results, meetings, assumptions, scenarios, etc.

### *3. Specific Regional Practices*

SPP incorporates findings of recent stakeholder engineering analyses for projects in and around the SPP footprint. SPP obtains copies of FERC Form 715 reports from its members for its independent review. SPP then documents the findings without disclosing any particulars in the Regional Expansion Plan. Stakeholders are to provide copies of any pertinent study or report that would be beneficial to the SPP staff. Documents are not shared unless authorized by the stakeholders. Model data is shared with SPP Members who are bound by SPP Bylaws, Membership Agreements, and FERC and State Codes of Conduct. Non-members must sign a Non-Disclosure Agreement to receive study models and data. Non-members are required to fill out Identification Forms to receive access to models and data. Non-disclosure agreements and Identification Forms are available at SPP's website; http://www.spp.org.

**Figure 1**
**SPP REgional Planning Process (2 year cycle)**




Source: GANTT

### *a) Planning Horizon*

SPP has proposed a two year planning cycle using a 10-year horizon. During the first year, SPP will develop an expansion plan based on reliability needs. During the second year, SPP will assess the system to determine market needs based on economic expansion plans. Study models will be posted on SPP's password protected website. The study will monitor facilities 100 kV and above. Details regarding projects will be made available, but national security concerns may limit availability of some data which will only be available on SPP's password protected website.

### *b) Principles of the Region*

SPP adheres to the NERC Transmission Reliability Planning Standards. Base case and N-1 Assessments are made for the entire SPP footprint and neighboring control areas. SPP assesses the reliability of the transmission network during summer operating conditions (short-term and long range). SPP plans for multiple contingencies and extreme disturbances. SPP Members are required to review and submit mitigation plans; annually review mitigation plans and effectiveness of operating directives; and investigate long-term solution for operating directives.

### *c) Cost Allocation and Cost Determinations*

SPP allocates costs, determines pricing, and resolves disputes through the administration of the processes described in its FERC filed Open Access Transmission Tariff, which is also available at SPP's website, http://www.spp.org.

## B. Review of Operations Procedures of SPP

SPP performs the following major services related to operations for their members:

- independent reliability coordination,
- administration of a FERC approved transmission service tariff,
- a computer-based telecommunications network,
- regional transaction scheduling, and
- operating reserve sharing.

### *1. Standards and Compliance*

SPP administers compliance with NERC's Operating Policies and Planning Standards. Responsibilities for compliance with the NERC Operating Policies and Planning Standards are described on the NERC website. The NERC website describes clearly defined consequences that are set in place for non-compliance, however, compliance, at this time, is voluntary.

#### *a) SPP Criteria*

SPP Criteria is considered as the policies, standards or principles of conduct by which the coordinated planning and operation of the SPP interconnected electric system is achieved. As stated in the introduction to the SPP Criteria manual:

> A primary purpose of SPP is to facilitate joint planning and coordination in the construction and operation of the generation and transmission network of the individual members so as to provide for increased operating efficiency and continuing service reliability, both in SPP and the contiguous regions. To assist in achieving these objectives, the members of SPP recognize that common criteria and procedures must be used in the planning and operation of the combined electric system for cost effective, adequate and reliable bulk power supply. This Criteria presents the characteristics of a well-planned bulk power electric system, describes the basis for model testing and lists the reliability and adequacy tests to be used to evaluate the performance of the SPP bulk electric system, and describes coordinated operating procedures necessary to maintain a reliable and efficient electric system. Reliable operation of the interconnected bulk electric system of SPP requires that all members comply with this minimum Criteria. Compliance with these Criteria is considered essential to a well planned and operated electric system, and is mandatory for all SPP members. Adherence can be expected to provide adequate and effective safeguards against the occurrence of uncontrolled area-wide power disturbances and will also provide efficient utilization of the electric system resources. This Criteria is also intended to serve as a guideline for developing more specific and definitive criteria by each member of SPP. It is the policy of SPP to maintain as high an interconnection capability with adjoining regions as is economically prudent. Interconnections with adjoining regions shall be designed such that SPP will remain interconnected following all of the more probable transmission and generation outage contingencies. Emergencies that occur in adjoining regions can affect SPP, just as the emergencies within SPP can affect adjoining regions. Therefore, joint studies shall be made on a regular basis to investigate various system emergencies that can occur and their effects on the electric system. In this way, the effectiveness of existing and planned interconnections shall be periodically measured and the design of the system periodically updated so that the interconnection capability and reliability shall be maintained.

### *b) Independent Reliability Coordination Services*

SPP Criteria 5 details the reliability coordination procedures utilized by SPP. SPP, on behalf of the membership, is a NERC approved independent reliability coordinator for the SPP footprint. The SPP Reliability Coordinator is the highest operating authority and is charged to ensure the transmission system is monitored and appropriate control action performed to ensure the transmission system is operated so that instability, uncontrolled separation, cascading outages, or equipment damage will not occur as a result of the most severe single contingency. They are responsible for implementing transmission loading relief procedures, as detailed in SPP Criteria 14, in a fair and equitable manner. The SPP Operating Reliability Working Group (ORWG) maintains, coordinates and implements Criteria related to the reliable and secure operation of the bulk electric system operated by the members of the Southwest Power Pool (SPP). The ORWG provides oversight and direction for the Reliability Coordinator function of the SPP. The ORWG also is responsible for ensuring compliance of the SPP Criteria with NERC Operating Policies and Standards.

### *c) Administration of a FERC Approved Transmission Service Tariff*

SPP administers an open access regional transmission service tariff, as approved by FERC, for the SPP footprint. The SPP Regional Tariff Working Group (RTWG) is responsible for development, recommendation, overall implementation and oversight of SPP's open access regional transmission service tariff. The RTWG will further advise the Staff on regulatory or implementation issues not specifically covered by the tariff or issues where there may be conflict or differing interpretations of the tariff. Details of the SPP Open Access Transmission Tariff business practices can be found at: http://www.spp.org/Publications/SPP_Business_Practices.doc. The SPP OATT can be found at: http://www.spp.org/Publications/SPPTariff_copy.pdf

### *d) A Computer-Based Telecommunications Network*

SPP operates a computer-based telecommunications network to facilitate the exchange of reliability data between the SPP control area operating centers and the SPP Reliability Coordinator. Additionally, this network is tied into the NERC Inter-Regional Security Network (ISN), to facilitate the exchange of reliability data across NERC. SPP also has deployed an emergency communications network of satellite phones located at each SPP control area operating center.

### *e) Regional Transaction Scheduling*

SPP administers an electronic scheduling system for the SPP members to facilitate the verification and approval of transmission service schedules. SPP acts as the scheduling agent for purposes of the SPP regional tariff. As such, SPP reviews and approves all tags involving SPP regional transmission service and provides a net scheduled interchange (NSI) value for each SPP control area to use for regulation purposes. To date use of the SPP generated NSI value is voluntary. However, SPP is moving towards full implementation where all members will use the SPP generated NSI value. Additional information on the SPP regional scheduling practices can be found at: http://www.spp.org/Publications/ How-To-Do-SWPP-Regional-Scheduling.doc and at http://www.spp.org/Publications/RTO_SS_26april01.ppt

### *f) Operating Reserve Sharing*

SPP operates a Reserve Sharing Group, as per the requirements in SPP Criteria 6. The Reserve Sharing Group maintains distributed generating operating reserves that are available to respond to an operating

reserve contingency event in order to provide adequate regulation of frequency and control area tie line power flow without shedding firm load or curtailing firm power sales.

### *2. SPP Corporate Governance*

SPP members approved Bylaws modifications April 27, 2004 to change its governance to a completely non-stakeholder Board of Directors with the addition of stakeholder committee called the "Members Committee." Additionally, on April 26, 2004 the Regional State Committee (RSC) for the Southwest Power Pool formed, adopted its bylaws and elected officers. The RSC provides collective state regulatory agency input on matters of regional importance related to the development and operation of bulk electric transmission. The SPP RSC is comprised of retail regulatory commissioners from agencies in Arkansas, Kansas, Missouri, New Mexico, Oklahoma and Texas.

On February 10, 2004, the FERC issued an order in the SPP RTO filing docket (RT04-1) conditionally approving SPP as an RTO. Per the order, SPP was directed to, among other things, transition to a non-stakeholder Board of Directors as a pre-condition to RTO approval. This transition was contemplated to occur immediately following RTO recognition in SPP's initial filing.

At its March 16, 2004 meeting, the SPP Board of Directors approved the Strategic Planning Committee's (SPC) recommendation to move forward in complying with all conditions/issues in the SPP RTO order. FERC was clear in its requirement that SPP transition to the non-stakeholder Board of Directors in advance of receiving RTO recognition. FERC required that this transition occur as soon as possible in that SPP was already making implementation decisions regarding Order 2000 compliance. The SPC recommended and the Board of Directors concurred with the changes to the SPP Bylaws necessary to accomplish these requirements. Pursuant to Section 8.0 of the current Bylaws, changes to Section 4.0 of the Bylaws regarding the structure and authorities of the Board of Directors must be approved by the Membership.

Additionally, FERC's Order conditionally approving SPP as an RTO directed SPP to modify its governance structure. The order provided direction as to the sectors that must be represented on the Members Committee and the Corporate Governance Committee (formerly the Nominating Task Force). The Strategic Planning Committee (SPC) reviewed the sectors of other regional organizations, and the sectors included in FERC's White Paper on Standard Market Design. In considering those and the requirement as stated in SPP's RTO Order, the SPC formulated a structure to comply with the Commission's directive. The Board of Directors accepted that recommendation at its March 16, 2004 meeting.

Subsequently, SPP staff facilitated discussions among the members in the various sectors in order to select representatives for the Corporate Governance Committee. In accordance with Sections 5.1 *Members Committee* and *6.6 Corporate Governance Committee* in the Bylaws dated May 1, 2004, the Corporate Governance Committee then met for purposes of creating a slate of nominees for the Members Committee for consideration and election by the membership (Attachment). In accordance with those Bylaws, it is the Membership's responsibility to elect the representatives to serve on the Members Committee. The slate of nominees presented for the Members Committee to become effective May 1, 2004 was approved April 27, 2004.

### *a) SPP Board of Directors Duties*

The Board of Directors acts in the best interest of SPP in its management, control and direction of the general business of SPP. The Board of Directors solicits and considers a straw vote from the Members Committee as an indication of the level of consensus among Members in advance of taking any actions other than those occurring in executive session. Its duties include, but are not limited to the following:

a. Direct activities of all SPP Organizational Groups;
b. Serve on SPP Organizational Groups;
c. Remove Members, and approve the re-entry of Members that have been removed;
d. Authorize all major contracts and debt instruments;
e. Select and review the performance of Officers, who shall serve at the pleasure of the Board of Directors;
f. Determine positions, duties, qualifications, salaries, benefits and other necessary matters pertaining to the SPP Staff;
g. Review, approve, disapprove or recommend revision to the actions of any Organizational Group;
h. Act on appeals pursuant to Section 3.10;
i. Approve or revise the operating and capital budgets and any additional expenditures;
j. Convene a meeting of Members at least annually;
k. Approve amendments to these Bylaws;
l. Approve amendments to the Membership Agreement;
m. Approve Criteria pertaining to planning and operating standards and policies and penalties for non-compliance with such Criteria; and
n. Authorize filings with regulatory bodies.

### *b) Composition of SPP Board of Directors*

The SPP Board of Directors consists of seven persons. The seven Directors are independent of any Member; one Director serves as the President of SPP. A Director is not limited in the number of terms he/she may serve. The President of SPP is excluded from voting on business related to the office of President or the incumbent of that office. No other SPP staff member is permitted to serve as a Director.

### *c) Qualifications of SPP Board Directors*

Directors must have recent and relevant senior management expertise and experience in one or more of the following disciplines: finance, accounting, electric transmission or generation planning or operation, law and regulation, commercial markets, and trading and associated risk management.

### *d) Conflicts of Interest*

Directors cannot be a director, officer, or employee of, and cannot have any direct business relationship, financial interest in, or other affiliation with, a Member or customer of services provided by SPP. Directors may indirectly own securities through a mutual fund or similar arrangement (other than a fund or arrangement specifically targeted toward the electric industry or any segments thereof) under which the director does not control the purchase or sale of such securities. Participation in a pension plan of a Member or customer is not deemed to be a direct financial benefit if the Member's or customer's financial performance has no material effect on such pension plan.

### *e) Terms and Election of SPP Board of Directors*

Except for the President, a Director of the SPP Board is elected at the meeting of Members to a three-year term commencing upon election and continuing until his/her duly elected successor takes office. Initial staggering of terms was decided by lottery with two Directors terms to expire in the first year, two in the second year, and two in the third year. The election process is as follows:

### *f) Resignation and Removal of SPP Board of Directors*

Any SPP Board Director may resign by written notice to the President noting the effective date of the resignation. The Membership may remove a Director with cause by the vote of a majority of each Membership sector at a meeting of Members. Removal proceedings may only be initiated by a petition signed by not less than twenty percent of the Members. The petition must state the specific grounds for removal and specify whether the removal vote is to be taken at a special meeting of Members or at the next regular meeting of Members. A Director who is the subject of removal proceedings is given fifteen days to respond to the Member petition in writing to the President.

### *g) Vacancies on the SPP Board of Directors*

If a vacancy on the SPP Board occurs, the Corporate Governance Committee presents to the Board of Directors for consideration and election an interim Director to serve until a replacement Director is elected and takes office. A special election is held at the next meeting of Members to fill the vacancy for the unexpired term. The replacement Director takes office immediately following the election.

### *h) Functioning of the SPP Board of Directors*

In reaching any decision and in considering the recommendations of any Organizational Group or task force, the Board of Directors abides by the principles in the SPP Bylaws.

### *i) Meetings and Notice of Meetings of SPP Board of Directors*

The Board of Directors meets at least three times per calendar year and additionally upon the call of the Chair or upon concurrence of at least four Directors. At least fifteen days' written notice is given by the President to each Director, the Members Committee, and the Regional State Committee of the date, time, place and purpose of a meeting of the Board of Directors, unless such notice is waived by the Board of Directors. Telephone conference meetings may be called as appropriate by the Chair with at least one day's prior notice. Board of Directors' meetings include the Members Committee and a representative from the Regional State Committee for all meetings except when in executive session; provided however, the failure of representatives of the Members Committee and/or of the Regional State Committee to attend, in whole or in part, does not prevent the Board of Directors from convening and conducting business. The Chair shall grant any Member's request to address the Board of Directors.

### *j) Election and Terms of SPP Board Chair and Vice Chair*

The SPP Board of Directors elects from its membership a Chair and Vice Chair for two-year terms commencing upon election and continuing until their duly elected successors take office or until their term as a Director expires without re-election. The President of SPP may not serve as the Chairman of the Board of Directors. The Vice Chair shall act for the Chair:

a. at the request of the Chair;
b. in the event the Chair should become incapacitated and unable to discharge the functions of the office; or
c. if the office of Chair becomes vacant, until the next regularly scheduled meeting of the Board of Directors, at which meeting a new Chair shall be elected by the Board of Directors to fill the vacancy. The Chair shall appoint a director to fill a vacant Vice Chair position until the next meeting of the Board of Directors, at which meeting a new Vice Chair shall be elected by the Board of Directors to fill the vacancy.

### *k) Quorum and Voting of the SPP Board of Directors*

Five SPP Board Directors constitute a quorum of the Board of Directors; provided that a lesser number may adjourn the meeting to a later time. Decisions of the Board of Directors are by simple majority vote of the directors present and voting. Directors must be present at a meeting to vote; no votes by proxy are permitted. Voting is by secret ballot. The Secretary collects and tallies the ballots, and announces the results of a vote. Only voting results are announced and recorded in the minutes; individual votes are not announced or recorded.

### *l) Compensation of SPP Board Directors*

SPP Board Directors receive compensation as recommended by the Human Resources Committee, and approved by the Membership, and are reimbursed for actual expenses reasonably incurred or accrued in the performance of their duties.

### *m) Executive Session of the SPP Board of Directors*

Executive sessions of the SPP Board of Directors (open only to Directors and to parties invited by the Chair) are held as necessary upon agreement of the Board of Directors to safeguard confidentiality of sensitive information regarding employee, financial, or legal matters.

Additionally, FERC's Order conditionally approving SPP as an RTO required SPP to modify its *Committees Reporting to the Board of Directors,* per Section 6.0 of the Bylaws effective May 1, 2004. In accordance with Sections 6.0 Committees Reporting to the Board of Directors and 6.6 *Corporate Governance Committee* in the Bylaws dated May 1, 2004, the Corporate Governance Committee met for purposes of creating a slate of nominees for these committees for consideration and appointment by the Board of Directors. In accordance with those Bylaws, it is the Board's responsibility to appoint the representatives to serve on these committees. The Board approved that slate on April 27, 2004.

## C. Sources Used in Summary of SPP Region

a. Southwest Power Pool. "SPP Regional Transmission Planning Summit," Kansas City, Mo., November 17, 2003.
b. http://www.nerc.com.
c. http://www.spp.org.

# Western Electricity Coordinating Council (WECC)

*Prepared by: Kiah Harris, Burns and McDonnell*
*Reviewed by: Marv Landauer, Bonneville Power Administration*
*and Steve Fausett, Tristate Transmission and Distribution Association, Inc.*
*(as of 11/22/04)*

## Overview of the WECC Region

The Western Electricity Coordinating Council (WECC) is a NERC reliability region. It was formed on April 18, 2002, by the merger of the Western Systems Coordinating Council (WSCC), Southwest Regional Transmission Association (SWRTA), and Western Regional Transmission Association (WRTA). Geographically, it covers all or part of fourteen western states and parts of Canada and northern Mexico, an area of approximately 1.8 million square miles. The WECC utilities serve approximately 71 million people. The demand in the WECC for 2004 was projected to be approximately 139,000 MW. The WECC utilities met this demand with a diversity of hydro-electric, coal, nuclear, gas and renewable resources.

The WECC is governed through a Board of Directors that is composed of 27 Members. Twenty of the Members are from five different Member classes, which consist of transmission owners, transmission dependent utilities, independent generators/load-serving entities, end-users/public interest groups, and regulatory agencies. The remaining seven Directors are Non-Affiliated Directors that are selected by the Board. The activities of the WECC are conducted through various Member committees that advise and make recommendations to the WECC Board.

The WECC as an entity does not have any regional transmission organization (RTO) or independent system operator (ISO) functions. However, utilities in California operate within the California ISO, which has adopted the standards of North American Electric Reliability Council (NERC) and the WECC with clarifications of certain contingency conditions to be met. Various utility groups within the WECC are reviewing organizational issues for creation of RTOs. This discussion covers the more broad aspects of the WECC planning process.

The WECC maintains an extensive website at www.wecc.biz that contains information on WECC activities, committee structure, and governance.

## A. Review of Current Planning Process of WECC

### *1. Responsibility for Planning in the Region*

Utilities within the WECC are guided in their planning activities by the WECC reliability criteria. This criteria includes the merged NERC/WECC Planning Standards, the WECC Power Supply Assessment Policy, and the WECC Minimum Operating Reliability Criteria. The Planning Standards contain the NERC planning standards for Table 1 contingency planning and some more stringent WECC standards for multiple outages with performance criteria for transient and voltage stability. Utilities are responsible for the generation interconnection studies and other requests for interconnections in accordance with NERC and FERC requirements.

In the Western Interconnection, individual project sponsors are responsible for the planning and decision making in the process of implementing transmission projects. The WECC has developed "Procedures for Regional Planning Project Review and Rating of Transmission Facilities" (Procedures) to assure that project sponsors work with their peers when developing projects. The background section of the Procedures document provides the history and development of this process.

Transmission planning within the WECC starts with the individual utilities performing analysis on their systems. In addition, projects may be proposed to local planning groups. Individual sponsors of projects then move the project into the regional planning process. If the projects identified within the regions are deemed significant, then they may move into a path rating process which includes broader input from the WECC. If the projects are not deemed significant, the projects are developed solely within the respective regions.

### *2. Regional Planning Process/Stakeholder Input*

WECC as an entity does not perform specific planning functions and relies on each of the member utilities to perform planning functions in accordance with the NERC requirements as modified by WECC guides. WECC's Procedures provide for peer review to ensure that stakeholders are satisfied that the requirements of the process are met. The project sponsor is responsible for demonstrating that it has met these guidelines. The peer review process culminates with a recommendation by the Planning Coordination Committee (PCC) to the WECC Board that the requirements of the process have been met and subsequent Board approval has been achieved. This peer review process does not engage in any commercial discussions, nor does it certify that all stakeholders are satisfied with the outcome. It addresses only that the process requirements have been met.

Projects which have significant regional impacts are responsible for demonstrating their conformity with the WECC Regional Planning Guidelines, in addition to complying with the reliability and transmission rating review process. The purpose of the WECC Regional Planning Guidelines is to:

a) Foster the development of a broad regional planning perspective among all stakeholders in the planning process,
b) Promote and encourage the most efficient use and development of the region's existing and future facilities that enhance interconnected system operation, and
c) Assure that all relevant regional planning issues are considered during the planning of transmission projects with regional significance.

The WECC has adopted the WSCC principles that stipulate "Resolved that WSCC facilitate a voluntary regional planning process and a Regional Planning Policy Committee be formed to explore and specifically define WSCC's role." Further, "The voluntary consensus based nature of the Regional Planning Project Review Process requires the WECC facilitate but not become either a champion or a challenger of competing projects proposed by its members." The WECC mission is to facilitate a reliable system. The WECC regional Planning guidelines ensure that each project shall:

a) Take multiple project needs and plans into account, including identified utilities' and non-utilities' future needs, environmental and other stakeholder interests.
b) Cooperate with others to look beyond specific end points of the entities' project to identify broader regional needs or opportunities.
c) Address the efficient use of transmission corridors (e.g., rights-of-ways, new projects, optimal line voltage, upgrades, etc.).

d) Identify and show how the project improves efficient use of, or impacts existing and planned resources of the region (e.g., regional benefits and impacts, transmission constraint mitigation) and cooperate with non-participant members in determining the benefits and impacts due to the project.
e) Identify transmission physical and operational constraints resulting from the project or that are removed by the project.
f) Coordinate project plans with and seeks input from all affected systems, sub-regional planning groups, power pools, and region-wide planning group(s).
g) Coordinate project plans with and seek input from other stakeholders (advisors) including utilities, independent power producers, environmental and land use groups, regulators (as represented by the advisors), and other stakeholders that may have an interest.
h) Review the possibility of using the existing system or upgrades and address the feasibility of alternatives.
i) Coordinate with potentially parallel or competing projects and consolidate projects where practicable.

It is the responsibility of the project sponsor to show that it has met the above Guidelines in a Regional Planning Report to the PCC.

The WECC planning process is a consensus-based voluntary process. The WECC includes a mediation process, which allows for a facilitator to try to achieve agreement among the parties if disagreements do occur. If this mediation process does not succeed, the parties have to seek recourse though another court or regulatory body such as FERC.

Final decisions on the acceptability of the planning process, the proposed ratings and other project technical issues are made by the WECC. Once the project has been approved by the WECC, it has essentially achieved consensus with the regional stakeholders. Final decisions to permit the construction of the project are made by the state, local and federal government requirements where the project is to be constructed. Final approval for construction, right of way acquisition, etc is the responsibility of the state, local and federal agencies.

### *3. Specific Regional Practices*

The WECC as an entity does not perform any planning functions. WECC does, however, compile transmission system models through an extensive data collection and modeling process. WECC Members utilize these models in their planning processes. Utilities and local or regional planning groups are the source of most projects which move through the planning process. There are three basic categories of projects that are reviewed. These are:

- Reliability Assessments
- Generator Impact Studies
- Economic Upgrades

Information on all projects that are currently in the process is available on the Western Interconnect Coordination Forum (WICF) Internet Web site (http://www.wicf.org). The WICF is primarily used for dissemination of data on transmission plans of the various WECC members.

The development of projects in the WECC comes from the utilities, independent power producers and other sponsors of projects. The WECC region does not have a general transmission tariff system and

each transmission owner establishes its own rates in accordance with regulatory requirements. Cost responsibility for the studies, project development and construction, operations and maintenance lies with the sponsor(s). Pricing of transmission service to incorporate new projects is determined by each transmission owner.

### *a) Rating Process*

If a transmission project sponsor desires protection of the rating of their project, or if the proposed projects affect the path ratings of existing facilities, the three phase rating process to establish path ratings is instigated. The three phase process includes the following major phases:

- Phase I starts with a project notification sent to the WECC. Once Phase I has been announced, a Proposed Rating is developed by the sponsor with general coordination with others.
- Phase II starts when the Phase I studies are accepted by the WECC committees and the path achieves a Planned Rating. The Phase II process entails the establishment of broad stakeholder advisory groups which could include members from utilities, regulatory bodies, consumers, independent power producers, environmental advocates, etc.
- Phase III starts when the project studies have been accepted and an Accepted Rating has been developed for the project. This phase allows the sponsor to move the project forward into construction, depending on the normal permitting and approval process which regulates the state or local area where the project is proposed. Phase III ends when the project enters service.

### *b) Planning Groups*

Regional planning groups have been formed to study a variety of additions in the WECC. The following is a list of currently active regional planning groups:

- Rocky Mountain Area Transmission Study (Wyoming/Utah/Montana/Idaho)
- Northwest Transmission Assessment Committee
- (BC/Alberta/Washington/Oregon/Idaho/Montana/Utah/Nevada/Wyoming)
- SW Transmission Expansion Plan (California-Arizona)
- SW Area Transmission Study (Arizona-New Mexico)
- Colorado Coordinating Planning Group
- California ISO Internal Planning Process
- Seams Steering Group – Western Interconnection

Of the various regional groups engaged in transmission system planning, the Seams Study Group –Western Interconnect (SSG-WI) is of particular interest. The SSG-WI was formed to facilitate continued progress toward a seamless western market, particularly through supporting the development of the electric infrastructure necessary to foster competitive wholesale electricity markets and efforts to promote an efficient market design process. It is expected that SSG-WI will play a major role in resolving the seams issues that will develop with the formation of RTOs in the west. The SSG-WI is strictly a voluntary organization that provides a forum for discussion and information exchange for planning in the western interconnection. The organization has developed draft regional planning process that furthers the economic expansion of the West's transmission system. SSG-WI also has efforts underway in the areas of congestion management, market monitoring, OASIS issues, and transmission pricing. The SSG-WI maintains a website at www.ssg-wi.com that has detailed information on its activities.

The stakeholders in the process are volunteers from any sector which desires to have input to the process. Consumers can be involved in the WECC planning process, the regulatory permitting process, subregional planning meetings and sponsored project meetings.

### *c) Reliability Assessment*

As a NERC region, the WECC is responsible for filing with NERC periodic updates on regional reliability assessments and other NERC reports. Utilities are responsible for supporting the planning requirements to meet the NERC/WECC Planning Standards. Utility projects associated with reliability improvements for load serving within a utility's service area are typically not involved in the WECC planning process and are planned by the respective utility. Approval for these local utility reliability projects is typically provided through the state, federal or local regulatory body for the utility.

Projects identified by the utilities in their reliability assessments are provided to the WECC for inclusion in the submission to the NERC. These projects are also included on the WICF list of projects. Typically, the projects reviewed in the WECC process are for a five to 10-year horizon.

Load flow models for the WECC are maintained by the WECC and include the transmission system facilities of the regional utilities typically down to the 115kV level. Utility specific models usually include additional lower voltage facilities.

### *d) Generator Impact Studies*

Generation interconnects are handled in accordance with the utility's and FERC procedures and only involve the WECC planning process when major facilities are needed to move the power long distances from the proposed plant to load centers or if the addition of the project impacts the capability of other members' facilities.

Sponsors of the proposed generation file an interconnect request with the specific transmission owner where the unit will be located. The process of the transmission owners, in general, follows the FERC requirements in the Proforma OATT. This process includes the necessary studies to determine the local interconnection requirements, the facility costs and the procedure for their construction. The process can take several months to complete, at which time the project sponsor will have the requirements and costs for the facilities necessary to allow connection of the generator to the system.

The ability to transmit energy from the facilities requires filing of the separate OASIS request and can include additional studies to determine the system upgrades necessary to support the transmission of energy from the plant to its expected load. The process follows in general the similar studies as for the interconnect request. If facility upgrades are necessary for firm delivery of the energy from the unit, the cost is developed by the utility. Where adjacent utilities' systems are affected, they will be included in the study.

Facilities resulting from the study may be included in the regional planning process if they affect other utilities or if the projects required are extensive in scope. Costs for the studies and upgrades necessary to connect the facility to the grid are born by the generator. Costs responsibility for system facilities necessary for the transmission of power to load may be credited back to the generator through the transmission service charge or recovered through the transmission provider(s) OATT.

### *e) Economic Upgrades*

Need determinations for economic upgrades to facilitate transfer of lower cost power to higher cost areas are sponsored by various parties and can include broad state coalitions that support the upgrade. These projects are typically within the planning process of the WECC and subregional planning groups.

The responsibility for the project lies with the sponsor(s) who determine the economic advantage of the addition based on the cost of the upgrade, the impact to the transmission service charges required by the transmission owner(s) involved and various other factors associated with the proposed project.

Ownership of the project lies with the sponsor(s). These projects may include transmission proposals for facilities that traverse hundreds of miles and affect numerous existing transmission paths. Since most transmission paths may have multiple existing owners, sponsors promoting an economic upgrade project will have to negotiate with the existing owners to determine rights for new projects. Any affects to existing paths will require the path rating process of the WECC be followed for the determination of the new path capability.

## B. Review of Operations Procedures of WECC

The WECC adheres to the both the NERC and WECC operating standards. In cases where there are differing standards between the two organizations, the more stringent standard is applied. The NERC operating standards are typically published in the form of NERC Operating Guides. The WECC standards are broadly described in the WECC "Minimum Operating Reliability Criteria" which is supported by a body of WECC Operating Policies and Procedures. WECC standards in general meet the NERC standards with certain additional more stringent standards. Responsibility for operations and maintenance lies with the owner of the facility. The responsibilities for operation and maintenance jointly owned facilities are negotiated between co-owners.

Consumers have input to the process through representation on WECC committees under the state and provincial members. Proposed standard changes can be initiated by "anyone having a legitimate interest in electric system reliability." The WECC includes consumers at the retail or wholesale level as parties having legitimate interests.

The WECC has implemented the WECC Reliability Management System (RMS), a reliability compliance agreement that binds the signatories to operating, maintaining, and planning the transmission system in the west in a reliable manner. The agreement establishes definitive and measurable reliability criteria that the signatories must meet, the assessment of written and monetary sanctions, a governance committee structure, an arbitration process, and an appeal process. Participation in the RMS is open to all transmission operators in the WECC on a voluntary basis. The participant agreements and reliability criteria agreements that constitute the RMS have been filed at FERC. The RMS currently has established standards and performance levels for the following:

- Operating reserves
- Disturbance control
- Control performance
- Operating transfer capability
- Relay settings and applications
- Remedial action schemes
- Operator certification
- Unscheduled flow relief
- Transmission maintenance standards
- Interchange schedule tagging
- Generator automatic voltage regulators
- Power system stabilizers

At the present time, all but two of the WECC major transmission owners are participating in the RMS

## C. Sources Used in Summary of WECC Region

a. WECC Mission and Goals.
b. WECC Reliability Criteria.
c. WECC Bylaws.
d. WECC Reliability Management System Agreement.
e. Voting Procedures for WECC Standing Committees.
f. Dispute Resolution WECC Procedure Appendix C.
g. WECC Procedures for Regional Planning Project Review and Rating Transmission Facilities.
h. Process for Developing and Approving WECC Standards.
i. Amended and Restated Bylaws of California Independent System Operator.

# Seams Steering Group – Western Interconnection (SSG – WI)

*Prepared by: Marv Landauer, Bonneville Power Administration*
*Reviewed by: Kiah Harris, Burns and McDonnell*

Seams Steering Group-Western Interconnection Planning Work Group (SSG-WI PWG) is a group formed by the three RTO/ISOs (some are still being formed) in the Western Interconnection: California ISO, Grid West (formerly RTO West) and WestConnect. The SSG-WI PWG was established to provide a forum for further the development of a robust west-wide interstate transmission system, an important pre-requisite for a seamless electricity market in the west. Subregional transmission planning processes have also been established to facilitate transmission planning and expansion for specific geographic areas within the Western Interconnection in conjunction with the region-wide SSG-WI process.

The SSG-WI PWG has developed a description of the SSG-WI Planning Function and how it interacts with other Planning processes within the western Interconnection. This description can be found at http://www.ssg-wi.com/documents/256-Planning_Process___Approved_by_SSG_August_5__2003.doc

Below is a portion of that document that describes the SSG-WI Planning Process.
SSG-WI Planning Function and its Interactions
Within the Western Interconnection

## Introduction

The three proposed western RTOs (RTO West, California ISO and WestConnect) jointly filed a report with FERC on January 8, 2003. Included in that report was a description of the elements of a draft SSG-WI planning process with a diagram depicting the flow of information within this process and with other interfacing processes. The filing indicated that the planning process was still being worked on and it was expected to evolve over time as experience is gained with interconnection wide transmission planning. The January 2003 filing also identified four major issues with this planning process that needed to be addressed to make the planning process functional.

This discussion reflects the result of review and update of the SSG-WI planning process described in the January 8, 2003 FERC report. This description of the SSG-WI Planning Function and its interactions within the Western Interconnection was developed by the SSG-WI Planning Work Group (PWG) in coordination with WECC and participating stakeholders. The PWG participants consist of representatives of the proposed RTOs, WECC, state regulators, public entities, and generation developers.

The primary driver for SSG-WI involvement in interconnection-wide planning is to address seams issues that arise between the three proposed western interconnection RTOs and to address major transmission constraints that affect a wide area of the Interconnection. The PWG recommends that whenever a planning seams issue is identified, SSG-WI should be prepared to address the issue. These seams issues can range from investigating long term inter-RTO transmission requirements to providing processes to address planning issues that affect one or more areas (for example, beyond the boundaries of a single RTO). This mainly includes working with other organizations and agencies that have interconnection wide scope. The PWG may work with individual entities or projects, upon their request, to facilitate the development of transmission projects.

The process described is applicable to both the pre- and post- RTO timeframes. However it is likely the process will evolve over time and will be reviewed and modified for post-RTO operation. The WECC portion of the process is an existing process, described in the WECC document "Procedures for Regional Planning Project Review and Rating Transmission facilities". The SSG-WI portion of the process is being implemented. The first SSG-WI Transmission Planning Report resulting from the SSG-WI portion of the process was issued in September 2003.

## The SSG-WI Planning Function

The SSG-WI Planning Function is a proactive, region-wide, transmission planning effort addressing transmission needs and alternatives to meet conceptual resource development scenarios. It is a stakeholder-involved process. It addresses congestion issues that impact the marketing of energy between RTOs or sub-regions[24], including the study of congested paths within a sub-region that have an impact on the ability to market between sub-regions. The study of transmission congestion within an RTO that does not impact other sub-regions remains the responsibility of the individual RTO's or local/subregional entities. However, RTOs or other entities may request the PWG to assist them in evaluating or developing specific projects.

Transmission planning performed by the RTO/ISOs, sub-regions and others within the West is an important part of the overall transmission planning process for the West and SSG-WI provides for a seamless transmission planning function throughout the interconnection.

The SSG-WI Planning Function provides information for Load Serving Entities (LSEs), other market participants and state/provincial policy makers to make informed decisions about the transmission implications of possible resource scenarios for meeting their load obligations. The time horizon is five years and beyond. In this timeframe, SSG-WI planning incorporates transmission expansions that are being implemented and investigates the subsequent needs of the West.

The SSG-WI Planning Function is open to industry segments and stakeholders within the Western Interconnection. It includes state and regulatory input. SSG-WI will coordinate its process and planning cycle with the three RTO's and others within WECC.

The PWG addressed the relationship between the SSG-WI Planning Function and the WECC processes. The WECC Regional Planning Project Review Process describes how transmission planning should take place within the West.[25] The SSG-WI and WECC processes are very complementary and reinforce each other. They will build on each other to foster successful completion of both processes. The SSG-WI Planning Function will provide proactive region-wide planning at the front end of the WECC process, while the WECC process will provide follow through and closure for sponsored projects moving through to implementation and facility rating.

WECC's coordinated planning policies and procedures for the Western Interconnection, documented in *Procedures for Regional Planning Project Review and Rating Transmission Facilities* can be found at www.wecc.biz. The Rating Transmission Facilities portion of the WECC procedures is clearly the responsibility of a project sponsor and beyond the scope of the SSG-WI Planning Function.

The SSG-WI Planning Function is expected to incorporate several inputs, including input from RTO, subregional and LSE expansion and resource plans. SSG-WI will perform an analysis of historical path use and future system needs. At this time, this analysis includes generation scenario modeling and

transmission long range planning. Other analyses may be added or modified in the future as the planning function evolves. The SSG-WI Planning Function takes the information gathered from outside sources (e.g. Subregional Planning Groups, RTOs/ISOs, PTOs, LSEs, non-RTO/ISO members) and the results of its own internal studies, and identifies future system needs and possible solutions to these needs, both transmission and non-transmission. This information is developed in an open process and disseminated to all interested parties and posted for input from the market participants and other parties interested in regional planning. As SSG-WI analyzes the transmission needs of the system (from its various inputs), it will also propose high-level alternative solutions to these problems.

These solutions include possible non-transmission solutions or an aggregate set of non-transmission alternatives. The level of detail of these non-transmission alternatives includes favorable location and sizes of generation and demand-side measures that would be necessary to impact the transmission alternatives. All of these possible solutions are posted for market input and comment before SSG-WI completes its expansion plan.

The SSG-WI Planning Function is envisioned to provide information to market participants to facilitate market participant decisions. The SSG-WI Steering Group decides which issues should be recommended to the RTOs for further analysis. The Planning Function incorporates any input received into its analysis and develops an annual SSG-WI Transmission Planning Report. SSG-WI is limited in its ability to go beyond the identification of possible future transmission and non-transmission additions for others to implement. It is not intended to be a decision-making body but rather take on a supporting and facilitating role. It does not fund or compel any projects nor allocate costs.

The goal is to get Project sponsors to come forward to review the SSG-WI planning work and to determine whether there is an economic interest in pursuing project development. Sponsors are responsible for determining if there are other interested projects participants and for taking projects through the WECC Regional Planning Project Review Process and subsequent project development actions such as environmental analysis and siting, permitting and approval requirements.

SSG-WI does not perform environmental analysis of sponsored projects. SSG-WI does not participate in siting processes or other governmental activities with analysis or recommendations unless requested by project sponsors or state agencies. SSG-WI limits its participation to making models available and explaining the extent of its analysis. Project sponsors are responsible for developing economic justification, arranging financing, designing and constructing the project.

### *Notes*

1 TOA, Article 2, III (A), Sections 2&3.
2 It is outside the scope of this assessment to review the public input practices of MISO member companies.
3 MTEP pg. 6, from Appendix B to the *Agreement Of Transmission Facilities Owners To Organize The Midwest Independent Transmission System (TOA).*
4 The MISO Advisory Committee is advisory to the MISO Board and is distinct from the Planning Advisory Board.
5 *2003 Intermediate Area Transmission Review of the New York State Bulk Power Transmission System (Study Year 2008),* New York Independent System Operator, March 23, 2004.
6 *Basic Criteria for Design and Operation of Interconnected Power Systems,* Northeast Power Coordinating Council, August 9, 1995.
7 *Guidelines for NPCC Area Transmission Reviews,* Northeast Power Coordinating Council, November 7, 2001.
8 *Reliability Rules for Planning and Operating the New York State Power System,* New York State Reliability Council, Version 6, March 14, 2003.

9 *Review of the Reliability of the New York Power Pool Bulk Power Transmission System in the Year 2006,* New York Independent System Operator, July 2000.

10 *2002 Load and Capacity Data,* New York Independent System Operator.

11 *NYISO Transmission Expansion and Interconnection Manual,* New York Independent System Operator, September 28, 1999.

12 The RTEP does not require the approval of the Members Committee.

13 State regulators may be legally prevented from endorsing the plan because new transmission projects usually need to be reviewed and approved by a state agency (typically the state public service commission). Having a state commission "approve" a plan before a filing is made at the state commission could be viewed as a violation of due process because the commission would be pre-judging the merits of a prospective application.

14 Our interest is in network upgrades that are needed as a result of new generating capacity coming into service. It is widely accepted that the generator should bear the cost of its interconnection to the grid.

15 MAAC is the Mid-Atlantic Area Council, one of the 10 Regional Reliability Councils of the North American Electric Reliability Council.

16 ARRs are a form of financial transmission right, denominated in MW, that entitle the holder to receive the congestion revenues associated with congestion between two specified locations within the PJM grid. They provide a financial "hedge" against congestion charges. Hence, a generator located at point A that receives 100 MW of ARRs from point A to point B would not have to pay congestion charges to send 100 MW of power to point B.

17 Order on Rehearing and Compliance Filings, 109 FERC ¶ 61,067 (Oct. 18, 2004).

18 The definition of "unhedgeable congestion" is an unresolved issue. In simple terms, "unhedgeable congestion" means congestion that cannot be hedged through the purchase of financial transmission rights.

19 Amendment to Operating Agreement Schedule 6, 1.5.7(d) (2) on First Revised Sheet No. 185D.

20 See PJM Compliance Filing, Docket No. RT01-2-014, April 21, 2004, p. 14.

21 Of course, the value of the ARRs can and likely will change significantly over a 30-year period.

22 PJM also is the security coordinator for American Electric Power's service area even though AEP is not yet a member of PJM.

23 PJM performs such functions as part of its security-constrained unit commitment and dispatch and LMP-based congestion management.

24 The term "sub-region" refers to a geographic sub-area of the Western Interconnection. The term "region" refers to the entire Western Interconnection.

25 The WECC Regional Planning Project Review Process is described in WECC, *Procedures for Regional Planning Project Review and Rating Transmission Facilities.* Currently, the WECC Procedures state that "the subject of this report . . . . is limited to identifying how transmission project sponsors should work and interact with their peers *when developing a project* that has a significant regional impact." *Id.* at 1 (emphasis added).

**Consumer Energy Council of America**
*Transmission Infrastructure Forum*

# Appendix B

# Cross Sound Cable Project: An Overview

*Prepared by:*
*Stephen Ward, Maine Public Advocate*

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## BACKGROUND

The CECA Transmission Infrastructure Forum asked its System Planning & Operations Working Group to develop a project outline of a successful transmission expansion project, including challenges faced in completing such a project. The Working Group chose the Cross Sound Cable transmission line expansion project as an illustration of a complex, highly contentious, but ultimately successful intertie project between the New York and New England control areas. Below is a brief outline of the Cross Sound Cable project and the chronology of events that led to the project's final approval.

### Project Summary

The project consists of a 24-mile undersea link between New Haven, Connecticut and Shoreham, New York that provides an additional tie between the New York ISO control area and the ISO-New England control area. The transmission cable was energized in July 2004 following a multi-party settlement that terminated a FERC proceeding initiated by Cross Sound and the Long Island Power Authority. The line has operated without incident since being energized in July 2004. The project was subject to significant uncertainty prior to that point.

The transmission link consists of two 150-kilovolt Direct Current (DC) cables capable of delivering electricity in two directions to land-based DC converter stations that connect with the New York and New England AC grids. The transfer capability of the project is 330 MW. The DC cable and converter stations originally cost $135 million to construct. Cross-Sound Cable Company owns and operates the project, having acquired it from Hydro-Quebec's subsidiary, TransEnergieUS. The project received FERC and ISO-New England approval in 1999 as a merchant transmission line whose rates are market-based rather than tariffed. Permanent operations in July 2004 put an end to a long and tumultuous history of controversy over the line during the prior four years.

### Project History

The project was briefly operational from August 2003 to May 9, 2004, due to an emergency order from the U.S. Department of Energy following the August 14, 2003 Northeast Blackout. Two Connecticut

state officials (the Attorney General and the head of the Department of Environmental Protection) successfully challenged DOE's emergency order, contending that its emergency basis expired when the grid was stabilized in August 2003 after the blackout. Ultimately the project went forward only when the Connecticut Attorney General and the Department of Environmental Protection extracted concessions from Cross Sound, including a $6 million grant for research and restoration activities in Long Island Sound, that caused them to terminate their opposition at FERC after five years of struggle.

Following interconnection approval from ISO-New England in 1999 under NEPOOL's Section 18.4 provisions, the project was first energized for testing in 2002. The project received all necessary approvals from the Connecticut Siting Council in January 2002, following a public hearing process. The Connecticut Superior and Appellate Courts and the Second Circuit Federal Court of Appeals all heard appeals of aspects of the siting approval.

The Long Island Power Authority will use the line to sell surplus energy and capacity to southern Connecticut customers when the opportunity arises. Other major users of the line include marketers and brokers who have received capacity on the line, by means of contract entitlements. In addition to individual customers benefiting from access to New York-based resources at times of high prices within the ISO-NE control area (and vice versa), the tie line also potentially provides reliability benefits for both control areas. This is because the Direct Current design of the system guarantees that instability in one control area cannot cascade into the other control areas, while at the same time providing access to power during periods of scarcity.

The apparent basis for the objection of the Connecticut parties to the line was the expectation that in periods of high demand, power in Connecticut would be diverted to serve load on Long Island. In fact, during the August 14, 2003 blackout, the reverse was true: power from Long Island helped stabilize the grid in Connecticut.

## Conclusion

The painful history of this project illustrates the extent to which efficient grid operations depend entirely on a single proposition: electric consumers regardless of location benefit from access to transmission and generation capacity in a large multi-state region, even if they do not often rely on regional resources. This proposition is vulnerable to political challenges of all types. In this instance, powerful institutions in one state, Connecticut, mobilized to prevent electricity being transferred to another state in another power pool so that local generation resources could only be used locally. The events of August 14, 2003 demonstrate, if nothing else, that major grid disruptions occur on a scale that ignores local preferences and assumptions. When the largest boats capsize, the smallest do as well.

In this case, the Congressional delegation from the State of Connecticut, the Connecticut Legislature and two key state agencies (the Attorney General and the Department of Environmental Protection) used all available leverage to prevent the project from going forward. There was extensive involvement by the public, representatives of the public and by public agencies in many state and federal settings as part of this concerted effort (see attached Chronology). Those settings included state and federal regulatory agencies, state and federal courts, the Connecticut Legislature and the U.S. Congress. To be sure, both of New York's U.S. Senators were equally forceful in advocating for the line, along with the Long Island Power Authority. But at the end of the day, very significant resources were deployed and significant delay resulted due to Connecticut's desire to retain locally-generated power for local use. The August 14, 2003 Blackout in one fell swoop demonstrated how myopic this insistence can be insofar as

the restoration of electric service in Southern Connecticut depended, at least to a degree, on the energy transfers that the Cross Sound Cable made possible.

Finally, the Cross Sound saga also demonstrates that an effective regulatory agency, in this case FERC, may resolve an intractable problem merely by threatening to act unilaterally, unless a multi-party agreement is reached prior to a firm deadline. FERC's announcement that it would act unilaterally by June 25, 2004 (almost certainly to dismiss with prejudice the Connecticut agencies' request that the line be de-energized) was the factor that gave negotiations among the parties a high-priority and led to their success.

## Sources


a. NEPOOL Forecast of Capacity, Energy, Loads and Transmission: 2000-2009, April 1, 2000; April 1, 2001; April 1, 2002; April 1, 2003, ISO-NE.
b. Regional Transmission Expansion Plans, 11/7/02 and 11/19/01, ISO-NE.
c. Connecticut Attorney General website: www.cslib.org/attygenl/press.
d. ISO-NE website, "Section 18.4 Interconnection" and "legal."
e. www.iso-ne.con/smd/transmission_planning/status_of_18.4Applications/.
f. Cross-Sound Cable website: www.crosssoundcable.com.
g. New York ISO website: www.nyiso.com.
h. Trans Energie US website: www.transenergieus.com/projects.htm.
i. Conversation with Paul Peterson, Synapse Energy Economics, Cambridge, MA, April 14, 2004.
j. Conversations with Bruce Johnson, Connecticut Office of Consumer Counsel, New Britain, CT, April 15, 2004 and January 5, 2005.
k. Conversation with Kerim May, ISO-NE, Holyoke, MA, January 5, 2005.

## Cross Sound Cable Chronology, 1999 to 2004

| | | |
|---|---|---|
| 1. | ISO-NE receives 18.4 interconnection application for Cross Sound; subsequently approved. | 12/1/99 |
| 2. | FERC grants approval of market-based rate authority for project. | 6/1/00 |
| 3. | Connecticut Siting Council denies first application for Certificate of Environmental Compatibility and Public Need without prejudice, for a 24 mile bi-directional HVDC cable from New Haven to Brookhaven (two 150 KV Cables and a fiber-optic cable) transferring up to 330 MW. | 3/28/01 |
| 4. | Connecticut Siting Council proceedings begin on the 2nd application for a Certificate of Environmental Compatibility and Public Need. | 7/24/01 |
| 5. | Council holds public hearing on $135 M project. | 10/24/01-10/30 |
| 6. | Council releases Findings of Fact and grants project approval (CECPN). | 1/3/02 |
| 7. | AG requests reconsideration of Council decision (denied 1/17/02). | 1/9/02 |
| 8. | ISO-NE "Capacity, Energy, Loads and Transmission Report (CELT)" incorporates the Cross Sound project as a new transmission tie in 2002. | 4/1/02 |
| 9. | AG files for a stay based on cumulative environmental impacts and no demonstration of need (denied 4/02). | 4/5/02 |
| 10. | Cross Sound begins construction. | 5/10/02 |
| 11. | AG seeks Superior Court order reversing Council 1/31/02 approval. | 5/15/02 |
| 12. | Connecticut DEP issues Notice of Violation for "air-jetting" of sediments during construction. | 5/24/02 |
| 13. | AG and DEP seek injunction in Superior Court barring Cross Sound from energizing the line. | 8/1/02 |
| 14. | Line energized for testing. | 8/5/02 |
| 15. | Superior Court dismisses AG's Appeal of Council 1/3/02 approval. | 8/21/02 |
| 16. | AG files brief in Connecticut Appellate Court seeking reversal of Superior Court ruling. | 10/31/02 |

17. Cross Sound seeks Writ of Mandamus against DEP seeking favorable environmental ruling. 1/28/03

18. ISO-NE CELT report incorporates the Cross Sound Project for 2003. 4/1/03

19. Legislature enacts a moratorium (PL 02-95) on Sound crossings for electric, gas and telecommunications lines, vetoed by Governor 4/11/02. 4/3/02

20. Cross Sound appeals denial of Writ of Mandamus. 4/23/03

21. Appeal denied for Cross Sounds' request for Writ of Mandamus. 5/31/03

22. LIPA offers Connecticut firm energy over Cross Sound and Norwalk-Northport cables. 5/03

23. DOE Secretary Abraham grants emergency order for cable following 8/14/03 Blackout. 8/14/03

24. Cable energized on emergency basis. 8/15/03

25. Both New York Senators request that DOE order be made permanent. 8/22/03

26. DOE Secretary Abraham makes emergency order permanent. 8/28/03

27. LIPA wheels energy from ISO-NE to Connecticut via cable. 9/4/03

28. AG withdraws state Supreme Court appeal of Council siting decision. 9/22/03

29. AG and DEP file for review of DOE order in Second Circuit Federal Court of Appeals. 3/30/04[1]

30. "Northeast ISOs Seams Resolution Report" includes reference to Project 22, projected for 2004 completion, finalizing end-state requirements for scheduling transfers over cable. 4/15/04

31. DOE Secretary Abraham rescinds the emergency order; line is de-energized. 5/9/04

32. Cross Sound files with FERC, jointly with LIPA, a request for re-energizing line. 5/21/04

33. NEPOOL votes to endorse re-energizing the line. 6/11/04

34. ISO-NE files a letter opposing DOE action on an emergency basis re-energizing the line. 6/14/04

35. Connecticut AG and DEP, the Connecticut DPUC, LIPA and Cross Sound jointly agree to energize the line on a permanent basis in exchange for environmental mitigation on the sea floor by Cross Sound and a $6 million grant to the Long Island Sound Study Management Conference. Twelve Connecticut legislators also sign the agreement. 6/24/04

36. Joint LIPA/Cross Sound FERC application withdrawn 6/28/04

37. Cross Sound Cable Reactivated. 7/2/04

***Note***

1 In 3/04: 475, 061 MWH to Long Island, 6,341 MWH to Connecticut; cable leased by LIPA for $20M/yr.

# Acronyms

| | |
|---|---|
| ARRs | Auction Revenue Rights |
| BPA | Bonneville Power Administration |
| CAISO | California Independent System Operator |
| CECA | Consumer Energy Council of America |
| CEP | Compliance Enforcement Program |
| DG | Distributed Generation |
| DOE | U.S. Department of Energy |
| EAB | Secretary of Energy's Electricity Advisory Board |
| EIA | Energy Information Administration |
| ELCON | Electricity Consumers Resource Council |
| EPAct | Energy Policy Act |
| EPRI | Electric Power Research Institute |
| ERCOT | Electric Reliability Council of Texas |
| FERC | Federal Energy Regulatory Commission |
| FRCC | Florida Regional Coordinating Council |
| FTRs | Financial Transmission Rights |
| GDP | Gross Domestic Product |
| ISO | Independent System Operator |
| ISO-NE | ISO-New England |
| ITC | Independent Transmission Company |
| LMP | Locational Marginal Pricing |
| MAAC | Mid Atlantic Area Coordinating Council |
| MAIN | Mid-America Interconnected Network |
| MAPP | Mid-Continent Area Power Pool |
| MISO | Midwest Independent System Operator |
| NARUC | National Association of Regulatory Utility Commissioners |
| NERC | North American Reliability Council |
| NIMBY | "Not In My Back Yard" |
| NPCC | Northeast Power Coordinating Council |
| NYISO | New York State Independent System Operator |
| OASIS | Open Access Same-time Information System |
| OMS | Organization of MISO States |
| PURPA | Public Utility Regulatory Policies Act |
| QFs | Qualifying Facilities |
| R&D | Research and Development |
| RDD&D | Research, Development, Demonstration and Deployment |
| RPS | Renewable Portfolio Standards |
| RSC | Regional State Committee |
| RTO | Regional Transmission Organization |
| SAIDI | System Average Interruption Duration Index |

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|---|---|
| SAIFI | System Average Interruption Frequency Index |
| SERC | Southeastern Electric Reliability Council |
| SMD | Standard Market Design |
| SPP | Southwest Power Pool |
| STEP | Southwest Transmission Expansion Plan |
| TDUs | Transmission Dependent Utilities |
| TEAC | Transmission Expansion Advisory Committee |
| TLR | Transmission Loading Relief |
| TVA | Tennessee Valley Authority |
| WAMS | Wide Area Measurement Systems |
| WECC | Western Electricity Coordinating Council |

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