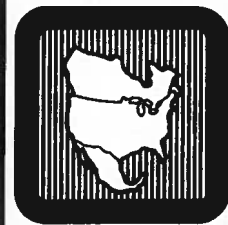


Reliability Assessment 1996–2005

The Reliability of
Bulk Electric Systems
in North America



North American
Electric
Reliability
Council

Reliability Assessment

1996–2005

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North American Electric Reliability Council

October 1996

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FOREWORD

About This Report

The North American Electric Reliability Council (NERC) Board of Trustees formed the Reliability Assessment Subcommittee (RAS) in 1970 to review annually the overall reliability of the existing and planned electric generation and transmission systems of the nine Regional Councils.

This *Reliability Assessment 1996–2005* report presents:

- An assessment of electric generation and transmission reliability through 2005,
- A discussion of key issues affecting reliability of future electric supply, and
- Regional assessments of electric supply reliability, including issues of specific Regional concern.

The report reflects the expertise, judgment, and interpretations of the RAS members. In preparing the report, the RAS interviewed representatives of selected Regions; reviewed summaries of Regional self-assessments, including forecasts of peak demand and planned resources; appraised utility plans for new electric generation resources and transmission facilities; and assessed the potential effect of legislation, regulations, and governmental policies on future electric supply reliability.

The data in the report reflect conditions projected as of January 1, 1996. Detailed background data are included in NERC's *ES&D* database and in the *Electricity Supply & Demand 1996–2005* summary brochure dated June 1996.

About NERC

Electric utilities formed NERC in 1968 to coordinate, promote, and communicate about the RELIABILITY of their generation and transmission systems. In short, NERC helps utilities work together to prevent blackouts.

NERC's members are nine Regional Councils and one Affiliate encompassing virtually all of the electric utility systems in the United States, Canada, and a portion of Baja California Norte, Mexico. The members of the Regional Councils are electric utilities from all ownership segments of the industry — investor-owned, federal, state, municipal, rural electric cooperative, and provincial — as well as some nonutility generators and electricity marketers.

EXECUTIVE SUMMARY

The electricity supply and transmission systems in the United States and Canada will be adequate to meet customer electricity demands in the near term and are capable of being operated reliably under a wide range of system conditions. Nevertheless, unanticipated equipment problems and extreme weather can combine to exceed the planned capability of these systems even when projections and assessments show them to be adequate.

The key issues identified in this ten-year Assessment, and *actions needed to address them*, are:

- Increased competition in wholesale electricity markets and open access to the transmission systems will present new challenges to the reliable operation of the interconnected bulk electric systems. *Improved security processes with appropriate and timely information sharing and continued coordination among generation and transmission operations are key elements in meeting these challenges.*
- The adequacy of existing and planned resources and transmission systems is less certain than in the past because the electric industry is moving to a more competitive electricity supply environment and commitments to new resources are being delayed to the last possible moment. Delays in placing generation or transmission facilities in service as needed can jeopardize the future reliability of the bulk electric systems. *The Regions and NERC will continue to assess overall generation and transmission adequacy and provide the market with the assessment results. Any generation or transmission shortfalls or weaknesses will be brought to the attention of the industry, the government, and the public.*
- Regardless of the electric industry restructuring that takes place, NERC will continue to define and ensure compliance with its reliability Planning and Operating Policies to ensure that a continuous and adequate supply is maintained and that transmission systems are operated within security limits. *All participants in electricity markets must comply with NERC and Regional Council reliability Policies and Standards.*
- As utilities reorganize to separate their transmission operational reliability functions from their wholesale electricity merchant functions to comply with FERC Order 889 and to satisfy other business objectives, *operational coordination and control for reliability must be maintained.*
- As the operation of the bulk electric systems becomes more complex, *system operators must continue to receive training and retraining, have sophisticated tools to effectively monitor and assess the reliability of their systems, and have clear authority to take timely action to ensure reliability.*

Near-Term Assessment (one to three years)

Committed generating capacity is adequate to serve expected customer demands in the near term. Similarly, the bulk transmission systems will be adequate and able to be operated reliably over a wide range of conditions provided that transmission additions are completed as planned.

Two specific areas of near-term reliability concern are:

- Limited operable generating capacity in the New England area of NPCC as a result of the 1996 shutdown of five nuclear generating units (4,080 MW), and
- Delays in the completion of the proposed Wyoming-Cloverdale 765 kV line between West Virginia and Virginia in ECAR. The U.S. Forest Service's recent recommendation against siting of this line through federal lands could block any further action on this critical transmission reinforcement. This line, which was originally scheduled for service in 1998, is needed to guard against a potential voltage collapse and resulting cascading failure of the transmission network in southeastern ECAR, with the possibility of cascading into neighboring areas.

Longer-Term Assessment (three to ten years)

In the longer-term, the adequacy of resources and transmission systems is less certain because the industry is moving to a more competitive wholesale electricity market and commitments to new resources are being delayed to the last possible moment. As this transition occurs, it will be important to continue to coordinate generating capacity additions with transmission expansion and use. The Regions and NERC will continue to assess overall generation and transmission adequacy and provide the market with the assessment results. Any shortfalls or weaknesses uncovered by these assessments will be brought to the attention of the industry, the government, and the public.

Generation Lead Times Shorter

In the latter years of the ten-year assessment period, a number of Regions and subregions are no longer reporting generating capacity additions needed to satisfy Regional criteria, although they do recognize such needs. The result is a decline in reported capacity margins compared to the last several years. This decline does not necessarily mean that future generation adequacy is in jeopardy. However, it does signal an increased reliance on short lead-time resources that allow commitments to be delayed until clearly required and reflects a shift toward a market-driven supply where customers choose the quantity and level of supply adequacy appropriate for their purposes.

Transmission May Be Limiting Factor

Generating unit lead times for gas-fired units continue to be relatively short, such that necessary generating capacity shown in the resource plans as “unknown” can actually be placed in service in two to three years. However, recent experience indicates that the planning and siting of associated transmission facilities necessary to integrate new generation resources into the interconnected network generally takes longer. Delays in placing transmission facilities in service as needed can jeopardize the reliability of the bulk electric systems.

Key Reliability Issues and Challenges

The reliability of the interconnected electric systems in North America will be just as important in the future as it has been in the past. The focus of responsibility for electricity supply adequacy, however, is shifting to the customer as the industry moves to a competitive market. This transition will require changes in how NERC assesses generation and transmission reliability of the bulk electric systems.

Regardless of the electric industry restructuring that takes place, NERC will continue to define and ensure compliance with its reliability Planning and Operating Policies to ensure that a continuous and adequate supply is maintained and that transmission systems are operated within security limits. Specific issues that must be addressed and improved include:

- accountability for reliability,
- processes for ensuring compliance with NERC and Regional Council reliability Policies and Standards,
- NERC's ability to keep pace with the rapid changes occurring in the industry, and
- the need for all market participants to share the necessary information for reliability assessments.

How all market participants respond to these issues will determine the degree to which the reliability of the bulk electric systems remains adequate and secure.

WSCC — Capacity margins and fuel supplies are projected to be adequate throughout the Region for the assessment period. The results of recent system disturbances, having Region-wide impact and follow-up technical studies to assess the unusual operating conditions during which the disturbances occurred, have heightened WSCC's concern regarding the potential for voltage instability in some areas. As a result, the WSCC members have intensified focus on the voltage stability issue and mitigating measures to ensure reliability throughout the Region. Other issues that continue to receive significant consideration are the uncertainty associated with competition and new industry structures, and the delicate balance between reliability and the economics of competition.

ASCC — Assessment of the 1996–2005 generation adequacy indicates that sufficient generating capacity margins exist in each of the three major customer demand areas: the Fairbanks area, the Anchorage Bowl, and the Kenai Peninsula.

Reliability risks for system-wide blackouts due to single contingency outages will decrease with construction of a second line connecting the Kenai Peninsula and the Anchorage Bowl and with the second transmission line between the Healy coal-fired generating plant and the major demand in the Fairbanks area.

NERC'S ACTION PLAN FOR RELIABILITY

Strategic Initiatives for NERC

In October 1995, NERC's Board of Trustees approved four *Strategic Initiatives for NERC* to ensure reliability in the new era of open transmission access. These Initiatives assign a higher priority and increased sense of urgency to several ongoing NERC Committee activities that address reliability issues. The issues that underlie these Initiatives are not new to NERC or the industry. However, changes in industry structure and regulation have pushed these issues to the top of NERC's agenda.

- Develop uniform definitions for determining available (transmission) transfer capability and related terms that satisfy both FERC and electric industry needs and which are to be implemented throughout the industry.
- Develop recommendations and a timetable for implementing formal, coordinated Regional and interregional "security" processes. "Security" refers to the electricity supply systems' ability to work reliably, even under adverse conditions.
- Review NERC Operating Policies and develop more clearly defined, uniform, and specific Operating Standards as soon as possible.
- Further develop the list of Interconnected (Ancillary) Operations Services that satisfies both FERC and electric industry needs.

All of these Initiatives are important. However, **the one Initiative that is of immediate strategic significance to the continued reliability of electricity supply and delivery systems in North America pertains to the second Initiative and the prompt implementation of the recommendations of NERC's Security Process Task Force.**

Studies of recent operating problems in the NERC Interconnections have concluded that better information sharing and better operational coordination are needed. The recent events in WSCC are no exception. The high levels of electric supply reliability that have been achieved in past years will be difficult to sustain in the open access era with today's moderate levels of information sharing and varying degrees of control area-to-control area coordination of emergency procedures.

The recommendations of NERC's Security Process Task Force call for:

- improving the sharing of operating data among control areas,
- establishing an Interregional Security (Information) Network,
- identifying and empowering Regional Security Coordinators, and
- developing Regional Security Plans.

At its May 1996 meeting, the NERC Board approved the Security Process Task Force's recommendations and a timetable for their implementation. Work is aggressively under way at both the NERC and Regional levels to complete implementation of all recommendations by January 1998. As aggressive as this timetable is, it may not be aggressive enough. The industry must find ways to accelerate the implementation of these recommendations to reduce the vulnerability of the interconnected bulk electric systems to potentially unforeseen, but in some cases preventable, outages.

Future Role of NERC

In addition to NERC's Strategic Initiatives, the NERC Board of Trustees, in early 1996, initiated an in-depth reassessment of NERC's role, responsibilities, and organizational structure in light of the rapidly changing electric industry environment. In September 1996, the Board unanimously accepted the findings and recommendations of its Future Role of NERC Task Force — II and directed the NERC Engineering and Operating Committees, under the auspices of the Task Force, to develop a detailed action plan to implement these recommendations. That plan will be presented to the Board at its January 1997 meeting. The plan will address:

- Establishing Reliability Standards,
- Measuring Performance, and
- Mandatory Compliance.

At the heart of this effort is the question of how NERC will ensure compliance with its Operating and Planning Policies in an increasingly competitive electricity supply and delivery market. NERC will likely continue to rely on some form of self-regulation as its means of ensuring compliance. However, the new compliance process will need to be based on:

- more aggressive oversight, review, and follow up of Committee and Board-approved recommendations,
- continuing and increased support and assistance as necessary to Regional Councils and their members,
- open, all-inclusive participation,
- use of alternative dispute resolution in lieu of sanctions, court actions, or referrals to regulatory bodies, and
- an unwavering demand for *excellence* in the planning and operation of interconnected bulk electric systems, up to and including direct CEO involvement.

Summary

The interconnected bulk electric systems in North America can and will continue to operate reliably, even as the electric industry evolves and changes, as long as:

- NERC and the Regional Councils continue to develop and maintain clear, consistent, and comprehensive reliability Policies and Standards.
- All entities that are involved in the generation, transmission, and interchange of electricity and which can affect the interconnected bulk electric systems understand, respect, and comply with NERC and Regional Council Policies and Standards.
- Regional Councils implement promptly and completely the recommendations in NERC's Security Process Task Force report, including the Interregional Security Network.

ASSESSING RELIABILITY IN A CHANGING INDUSTRY

The continued reliability of the interconnected bulk electric systems (electric Interconnections or “grids”) in North America is essential to an efficient electricity supply market and will be as important in the future as it has been in the past. However, as the industry transitions to a competitive market, customers will have more choices about the adequacy of their electricity supply. This transition will require a change in how NERC assesses generation and transmission reliability.

It is not yet clear how reliability will be assessed in a restructured, competitive marketplace. Regardless of the industry restructuring that takes place, NERC will continue to define and enforce reliability Policies and Standards to ensure that a continuous supply and demand balance is maintained and that interconnected bulk electric systems are operated within security limits. Specific issues that must be addressed include: accountability for reliability, compliance with reliability Policies and Standards, NERC’s ability to keep pace with the changes in the industry, and the willingness of market participants to share the information required for reliability assessments. How the market participants respond to these issues will bear heavily on the future reliability of the bulk electric systems.

Who Will be Accountable for Reliability?

Reliability is a combination of SECURITY (the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements) and ADEQUACY (the ability of the electric systems to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements). The security component of reliability is protected by the security function of individual control areas and coordinated through Regional and multi-Regional security coordinators. The adequacy component, however, is undergoing great change in the new competitive

environment. Beyond the basic reliability Policies and Standards established by NERC and the Regional Councils are a whole host of industry and individual utility practices and procedures related to operations, maintenance, testing, construction, etc., which are key influences on reliability.

Many different industry structures (Independent System Operators, Regional Power Exchanges, Regional Transmission Associations, etc.) are being proposed by the electric industry to achieve the benefits of a more competitive electricity supply market, while maintaining reliable system performance. A key issue for NERC in these restructuring proposals is to determine who will be accountable for ensuring

reliability in the future. Traditionally, this has been control areas and transmission operators. NERC reliability Policies and Standards need to continue to balance the interests of these *accountable* entities with the interests of those that are *affected* by the reliability of the bulk electric systems. Consistent, well understood, and fundamentally sound procedures and incentives to ensure that the NERC Policies and Standards (“Rules of the Road”) are followed must be in place. These rules must be consistently applied throughout the interconnected electric systems in NERC so that integration of various restructuring models can be accomplished while reliability is maintained. It will be important for all market participants to adhere to the NERC and Regional Council reliability Policies and Standards to ensure reliable system performance.

The term “reliability” can also have two meanings in the context of industry restructuring — bulk electric system reliability and individual customer supply reliability. Careful distinction between the two is very important. Bulk electric system reliability refers to the overall security of large portions of the interconnected systems, which affects electricity supply to millions of customers at the same time. In the future, individual customers will be able to make choices regarding the reliability of their own electricity supply. These customers will evaluate the costs to achieve the benefits of greater reliability against the savings of reduced reliability.

New industry structures will recognize that different customers have different supply reliability needs. These differences must be recognized and accommodated on the local level while not impacting the security of the bulk electric systems or the adequacy of supply to other customers.

As the industry responds to a more competitive market, customers will have more choices about the adequacy of their electricity supply. The choices that customers make must not cause the operations of the interconnected bulk electric systems to fall below the minimum reliability Standards set by NERC. The potential consequences to the economy and public health and safety are too great.

Monitoring and Enforcing Compliance

In the future competitive environment, peer pressure will not be as effective as it has been in the regulated electric utility industry of the past. It is likely also that compliance mechanisms will need to be different for electricity production standards (Adequacy) versus network integrity standards (Security). With respect to the Security function, all participants in electricity markets will continue to be required by NERC and the entities charged with the responsibility for wide-area security to follow the NERC "Rules of the Road." However, electricity production being a competitive market will require economic-based compliance mechanisms such as monetary

penalties, required load shedding if a customer's electricity supply is unavailable, or loss of trading privileges in the market for noncompliance. Loss of market privileges would put a supplier at a market disadvantage because they would be viewed as a "low reliability" supplier.

Because overall network security depends on maintaining a continuous balance between supply and demand and having the ability to quickly adjust generation or demand to relieve system security violations, it is paramount that effective compliance mechanisms be established. NERC must continue to focus on developing technically correct and consistent policies and procedures along with effective monitoring and compliance enforcement mechanisms to ensure that its policies and procedures are followed. NERC reliability Policies and Standards need to be consistent and written so that all market participants who own, operate, or use the interconnected electric systems will know what is expected of them. Consequences for noncompliance must be applied in a consistent, nondiscriminatory manner. NERC's role in setting these standards for both generation (electricity supply) and network security is clear, as is NERC's need to ensure strict compliance with network security standards. What is not clear is whether NERC should have some role in establishing and administering market-based processes for ensuring compliance with NERC-

established electricity supply standards.

"Quick" Action to Change Policies and Standards to Meet Changes in the Industry

Operating and planning practices and policies will continue to change as new participants, structures, and contracts develop to meet specific customers' demands. Procedures must evolve more rapidly to handle problems that surface in daily operations. NERC is streamlining its ability to develop and implement new and revised Policies and Standards that reflect the needs of the changing industry, while maintaining the reliability of the bulk electric systems. These Policies and Standards are the rules necessary to keep the marketplace a reliable forum in which to conduct business.

Future Supply Adequacy

Future supply adequacy is less certain today than it has been since the formation of NERC in 1968. Lead times for new gas-fired resources are shorter, utilities are postponing commitments for new capacity, new market mechanisms are evolving, and customers are looking beyond their traditional suppliers. Meaningful resource adequacy assessments require participants to provide accurate and complete information on future customer demands and resources. Information is required from all entities that control or operate generation or directly serve customer demand (native load or through "contract"). Increasingly, new resource needs are being reported with-

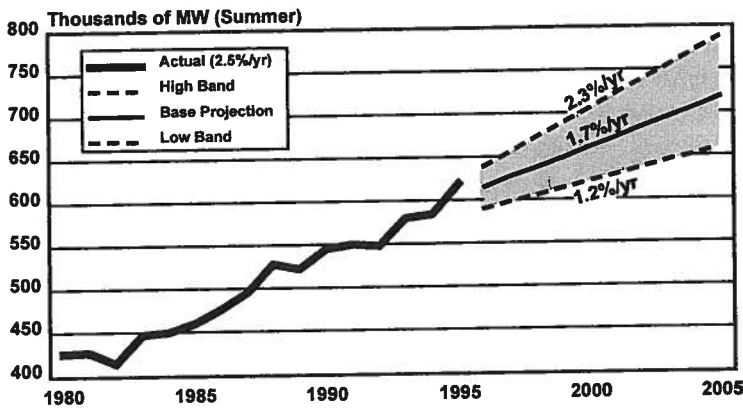
out identifying where those resources will be located or who will be responsible for providing them. This lack of identification can lead to “double counting” of resources or “under counting” of customer demand, making it difficult to perform accurate resource or transmission reliability assessments. NERC Policies require reporting the information required to perform supply adequacy assessments that can be used by all market participants. The NERC Load Forecasting Working Group is currently investigating data reporting requirements that will address and resolve these issues. The EIA Data Coordination Task Force is developing reporting requirements aimed at reducing double counting of resources. In a competitive industry, with separate generation and transmission activities, NERC may need to address different data reporting requirements so as to protect the confidentiality of competitively sensitive information but at the same time have sufficient information to perform meaningful adequacy assessments. The obligation to provide data for adequacy assessments may need to be required through contracts.

RESOURCES

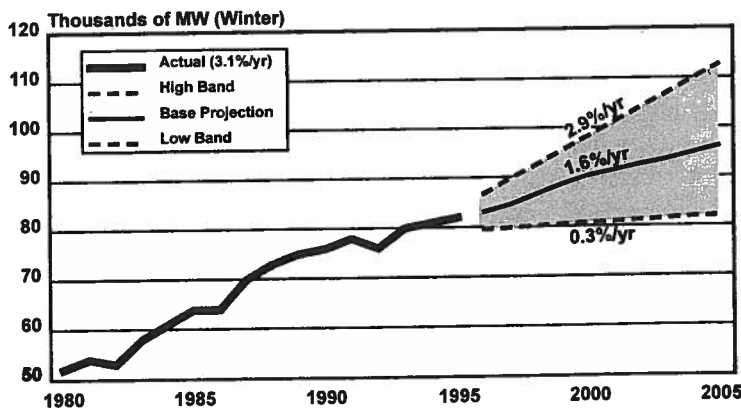
Committed resources are adequate to serve expected customer demands in the near-term. In the long-term, resource adequacy is less certain because the industry is in a period of transition to a more competitive electricity supply market. As the industry moves into a market-driven environment, it will be important to continue to coordinate resource additions with transmission expansion and use. The Regions and NERC should continue to assess overall resource adequacy and provide the market with these assessment results.

Figure 1

United States Peak Demand 1996–2005 Projection



Canada Peak Demand 1996–2005 Projection



Resource Adequacy

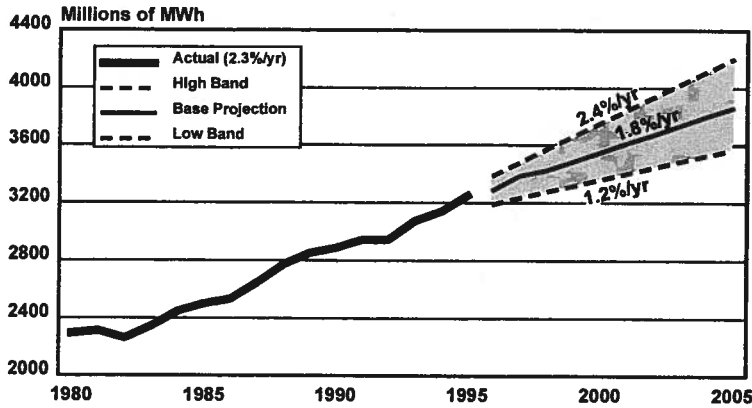
The projection of growth in the United States for peak demand and net energy for load over the next ten years is essentially the same as the last several years. The ten-year growth rates in Canada are somewhat less. High and low bands around the base forecast reflect a range of uncertainty in these forecasts (Figures 1 and 2).

The Regional projected resources, which have been assessed using their respective Regional reliability criteria, are judged to be adequate to meet projected demand through 1999. In the remaining years of the ten-year review period, a number of Regions and subregions are no longer reporting uncommitted resource additions needed to satisfy Regional criteria, contributing to a decline in reported capacity margins compared to margins projected in the last several years (Figure 3). This signals an increased reliance on short lead time resources and a strategy of delaying resource commitments until the last possible moment (Figures 4 and 5).

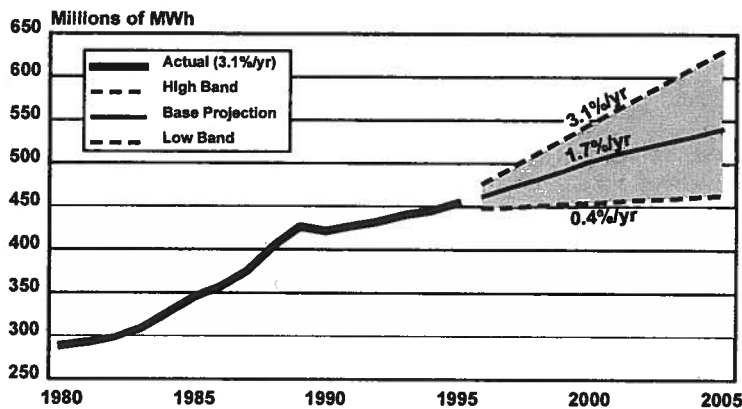
Resource adequacy problems can occur if several buyers rely on the same limited resource "pool" to supply future requirements. The Regions and NERC should continue to assess overall Regional and multiRegional resource adequacy and provide the market with these assessment results as a "market analysis" of future Regional resource needs.

Figure 2

United States Net Energy for Load 1996–2005 Projection



Canada Net Energy for Load 1996–2005 Projection



Resource Planning

Transmission and resource planning functions have traditionally been integrated due to the technical coordination that is required and the economic trade-offs that exist between them. However, as traditional utilities reposition themselves for competition, and in response to FERC Order 888, many are separating and reassigning the responsibility for the three core business functions: generation, transmission, and distribution. Such changes may make it more

difficult to ensure the coordination required for resource and transmission planning by fostering a reluctance to share information considered to be competitive and lead to a loss of synergy in the generation and transmission planning functions.

Although generating plant in-service lead times have been significantly reduced, such that capacity shown in resource plans as “unknown” can reasonably be placed in service in two

to three years, the transmission planning necessary to integrate these new resources into the systems has not been completed. Recent experience indicates that it may be more difficult to site transmission facilities than generation resources. Any delay in placing generation or transmission facilities in service as needed may jeopardize the reliability of the bulk electric systems. It may be desirable for market participants to develop and maintain an inventory of licensed or licensable plant sites and transmission corridors to help ensure that needed facilities can be constructed in a timely manner. In addition, those who will be planning generation resource additions need to actively participate in the regional transmission planning process as discussed under the “Transmission” section of this report.

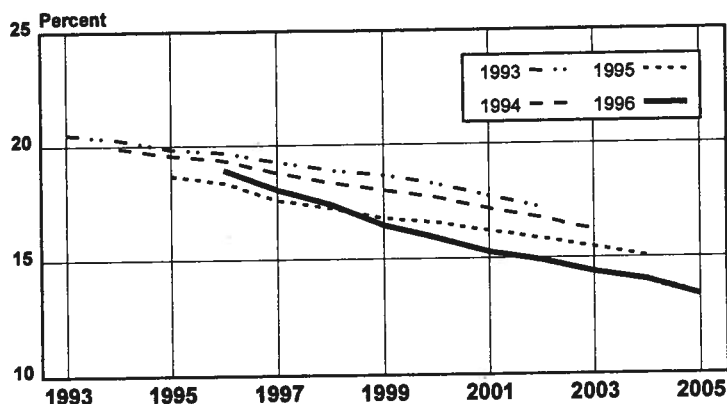
“The Market Will Provide — How? How Well?”

Under the existing system, an entity having an obligation to serve plans new capacity on the basis of forecast demand and a given supply adequacy criterion. With a market-driven system, a supplier will add new resources if a profit is anticipated, typically on the basis of existing and projected prices. The unique characteristic of electricity supply is the long lead time for developing the transmission required to integrate new resources into the bulk electric system.

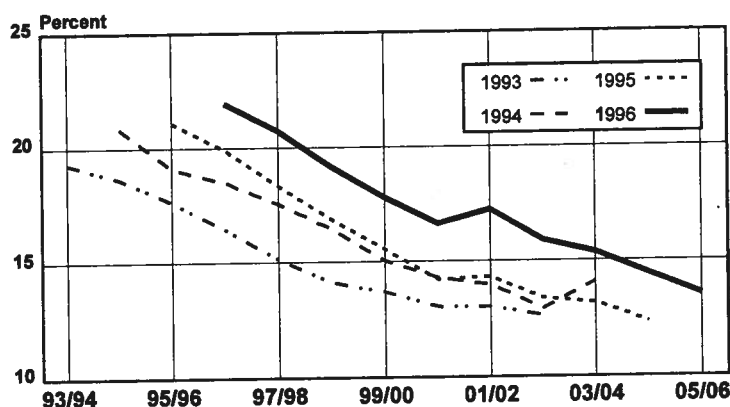
Discussions of resource adequacy — how, when, and by whom will new resources be

Figure 3

**Capacity Margins Trends
United States – Summer**



**Capacity Margins Trends
Canada – Winter**



developed — often center on the axiom, “the market will provide.” It is not clear how this will occur, since a fully functioning, totally deregulated resource market has not yet developed. If the market does not provide resources when and where needed, prices will rise and some customers will choose not to pay the price. Price elasticity is an integral part of a functioning market — the customer that is willing to pay for electricity will receive service. At some point, price signals

received by customers or service dissatisfaction of customers, will result in either construction of new resources or a reduction in demand.

The creation of markets to trade in electric power futures may provide useful information for all market participants and offset some of the resource uncertainty. As pricing of electricity futures sends signals to resource developers, incentives may be sufficient for them to commit construction capital. However,

for such signals to be effective for planning purposes, market signals must reflect the lead times necessary to construct new generation as well as any associated transmission. In the transition to a fully competitive electricity market, some resource adequacy problems could occur if price signals do not reflect needed lead times.

Other Challenges to Resource Reliability

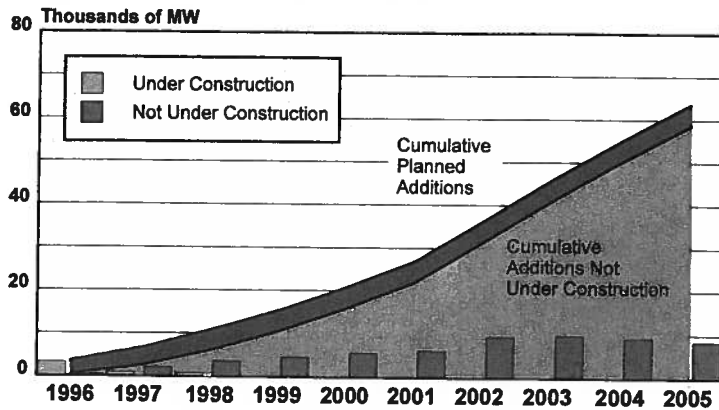
As the electricity supply industry becomes more competitively driven, several other challenges exist that could adversely impact resource adequacy if not addressed in a timely manner. Some of these challenges include: accurately projecting the demand to be served and the resources available to serve it, allocation of the responsibility for capacity margins, maintenance scheduling, and potential over-reliance on any particular fuel technology.

Demand forecasting

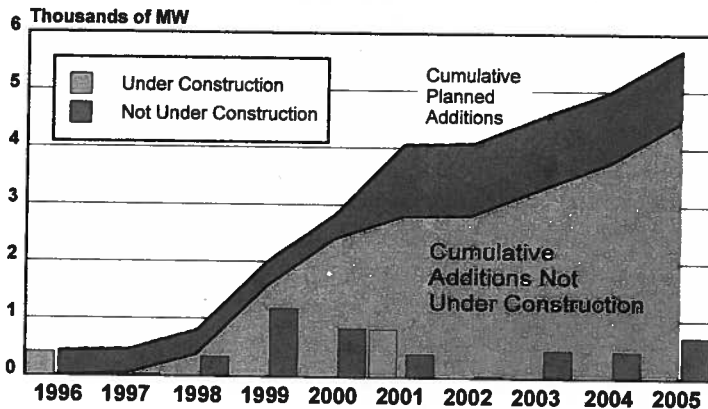
and reporting — Meaningful resource assessments require market participants to provide the necessary information on future demand and resources. Keeping track of the customers’ demand for electricity, the different levels of supply reliability, and who is responsible for providing reserves will become an increasing challenge as competitive suppliers seek to acquire new customers. The traditional demand forecasting and reporting systems of the Regional Councils and NERC will need to adapt to these challenges. The NERC Load Fore-

Figure 4

Annual and Cumulative Capacity Additions United States



Annual and Cumulative Capacity Additions Canada



casting Working Group is addressing these reporting needs.

Resource reporting — The electric industry is presently experiencing some “double counting” of capacity. Capacity is being sold by entities on a nonfirm basis and being reported by purchasers as firm capacity. Marketers aggregate many nonfirm purchases in their portfolio, to allow sales on a firm basis, similar to the way utilities use generation capacity margins to “firm up” supply. With the ex-

isting capacity reporting methods, the entity that sells nonfirm capacity to a marketer would report the capacity as its own installed capacity, since it is available to serve the seller’s own demand. In addition, the entity purchasing “firm” capacity from the marketer’s portfolio also reports it as capacity, thereby double counting it. As more participants enter the market, and as more market-driven mechanisms and marketing programs evolve to meet specific customer demands, the potential

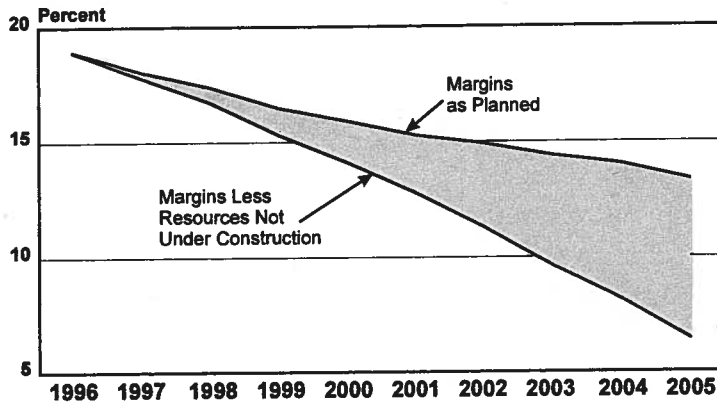
to lose track of the resources available to serve demand increases. The NERC-EIA Data Coordination Task Force is addressing capacity reporting issues.

Deliverability of purchased resources — Historically, utilities have offered each other generating capacity and energy at various levels of firmness. These levels of firmness represented a composite of generation availability and available transmission transfer capability. With an increase in market participants and as the industry moves to open access, there will be the possibility of tying firm capacity purchases together with nonfirm transmission. Customers contracting for capacity and energy services from any potential market participant will need to understand the firmness of each of the components of that service and ensure that the service contracts provide the overall level of reliability they specify.

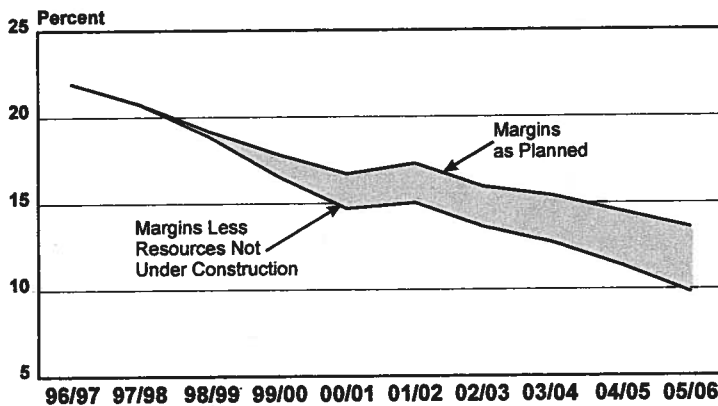
Capacity benefit margin — Transmission interconnections with neighboring electric systems provide for assistance during generation capacity emergencies. This “capacity benefit margin” reduces the required installed generation capacity margin that would otherwise be necessary to attain the same level of customer supply reliability without interconnections. As the responsibility for installed generating capacity margin shifts to the customer in the future, who is responsible for maintaining “capacity benefit

Figure 5

Capacity Margins United States – Summer



Capacity Margins Canada – Winter



margins” becomes less clear. With the advent of open access transmission, recognition must preserving the capacity benefit margin and its critical impact on resource adequacy. NERC has addressed this issue in its *Available Transfer Capability Definitions and Determination* report.

Fuel supply flexibility — Problems in fuel supply, delivery, priority, and inventory remain a reliability concern. Experience demonstrates that too much reliance on any single fuel can be a problem. As competition decreases resource margins, reliance on nonfirm, or interruptible fuel contracts will become less prudent. The ability to fuel switch at generating plants may become more important in the market-driven environment.

The bulk transmission system will support reliable operations in the near term (three to five years) provided transmission additions are completed as planned. Transmission system planning must include consideration of the needs and interests of all stakeholders. The determination of available transfer capability (ATC) must recognize the effects of all simultaneous transfers and parallel path flows and be made on a coordinated, wide-area basis recognizing how the transmission network is actually used. The Regional Councils and NERC will need to address reliability issues arising from the implementation of FERC Orders 888 and 889.

Near-Term Assessment

A key transmission line to enhance the reliability of the network is American Electric Power's proposed Wyoming-Cloverdale 765 kV line between southwestern West Virginia and western Virginia. The project, originally announced in the late 1980s with an expected service date of May 1998, and subsequently rescheduled to winter 2000/01, has recently received a major setback in its ability to construct this line. The U.S. National Forest Service recently issued a Draft Environmental Impact Statement for the approximately 12 miles of this line that will cross federal lands in which it recommends against the siting of this line through federal lands. This development could block any further action on this critical transmission reinforcement. The line is needed to guard against a potential voltage collapse and resulting cascading failure of the transmission network in southeastern ECAR and with the possibility of cascading into neighboring areas. This line would also significantly strengthen transmission capability from the Midwest to the Eastern Seaboard. Special operating proce-

dures are in place to limit power transfers and implement other emergency actions until the line can be placed in service.

Planning

The existing transmission system was planned, designed, and constructed to deliver electricity from generating stations to load. The interconnections among neighboring utilities were intended for reserve sharing (improved reliability and reduced investment in generating capacity), improved electrical stability, frequency control, and economic interchange. The ability to expand the transmission system when and as needed is crucial to maintaining a reliable electric system in the future. Issues related to industry restructuring will clearly affect how planning will be accomplished in a competitive market. Regardless of how the generation market evolves, the future security of energy supply will be dependent on the security and expansion of the interconnected electric transmission systems.

The transmission needs of all stakeholders must be considered simultaneously to plan an ade-

quate and reliable transmission system. These needs may in some cases overlap Regional boundaries as buyers look beyond their traditional suppliers. This will require close interregional planning and coordination of the needs of every entity requiring the use of the interconnected system. In addition, development and siting of new generation resources and how they will be used must be coordinated with existing and planned transmission to ensure adequate transmission capability is available to reliably integrate these resources into the system. Regardless of the process used for planning, it will continue to be difficult to approve and site new transmission lines.

Parallel Path Flows and Available Transfer Capability

In an interconnected system, the power flows of one utility will be carried in part by the transmission systems of other interconnected utilities. Transmission system planners and operators must adopt a wide-area, macro view of the network to reliably accommodate the parallel path flows inherent in the interconnected system. Parallel path flows and simultaneous transfers impact system transfer capability, and that impact will increase as power transfers across the system increase.

Under FERC Orders 888 and 889, all transmission providers must determine and offer for sale available transfer capability (ATC) taking into account existing obligations and allowing appropriate margins to maintain

reliability. Transmission owners are developing new processes to assess transmission system capability consistent with NERC's *Available Transfer Capability Definitions and Determination*, June 1996.

Electric utilities historically have recognized the need for transmission margin in the planning and operation of the interconnected transmission networks. With the introduction of mandatory, nondiscriminatory access, and the resulting need to quantify ATC for the competitive electricity market, there is now a need to formally address two types of transmission margin — Transmission Reliability Margin (TRM) and Capacity Benefit Margin (CBM). TRM is an amount of transmission transfer capability necessary to ensure the secure operation of the interconnected transmission network taking into account uncertainties in system conditions. CBM is an amount of transmission import capability reserved to ensure access to emergency power supplies, which reduces the amount of installed generation reserves that would otherwise be needed to meet generation reliability requirements.

The NERC Board of Trustees, at its May 13–14, 1996 meeting, approved the following recommendations pertaining to the determination and implementation of ATC throughout NERC:

1. All Regions (or subregions) should develop procedures for the determination and posting of ATCs and the al-

location of transmission services (including reservations and scheduling), taking into account the ATC Principles in NERC's *Available Transfer Capability Definitions and Determination* report.

2. NERC Planning and Operating Policies need to be reviewed and modified, as appropriate, to address the reservation and scheduling of transmission services recognizing the interdependent characteristics of the interconnected networks and the actual use that will be made of the networks for electric power transfers.
3. A NERC ATC Implementation Group should be formed to monitor and review the procedures developed by the Regions (or subregions) for determining ATC to ensure that they are in concert with the ATC Principles in this report. All Regions (or subregions) are expected to develop and submit such procedures and implementation plans to this NERC ATC group by January 1, 1997.

The NERC Engineering and Operating Committees, at their July 16–17 meetings, approved the scope of a Transmission Reservation and Scheduling Task Force to develop processes for the reservation of transmission services and scheduling of energy transfers that recognize the actual use being made of the Interconnections. In addition, the scope of the NERC ATC Implementation Working Group was approved to monitor the

procedures developed by the Regions for determining ATC.

OPERATIONS

Increased competition and open access to the transmission system will present new challenges to the reliable operation of the interconnected system. These challenges include the increasing number and complexity of schedules, coordination, and administration of ATC and unbundled Interconnected Operations Services. Better security processes with the appropriate and timely information sharing and continued coordination between generation and transmission maintenance are needed. More uniform Operating Policies and definitions, plus the ability to revise those Policies quickly, are essential keys to meeting these challenges. As the electricity market develops, security coordinators and control area operators who are charged with the responsibility for security must exercise their authority and enforce the Operating Policies.

Interchange Scheduling

Increased competition and open transmission access will increase the number of requests for interchange schedules and schedule modifications. Operators of the bulk electric system will be expected to meet the level of requests received. Better and more automated scheduling processes will help operators accommodate increased scheduling demands and still maintain reliability.

The NERC Security Process Task Force (SPTF) has made recommendations to ensure continued reliability in a more complex interchange scheduling environment. This Task Force has determined that security coordinators and increased information sharing are required. The recommendations of the SPTF have been approved and are being incorporated into the NERC Operating Policies and complied with by the industry. The Regions are developing formal security plans that will

govern the implementation of the SPTF recommendations.

Transaction Complexity

As customers look for ways to reduce their energy costs, they may opt for lower levels of service reliability by purchasing nonfirm electricity supplies and transmission services. The wide range of different terms and conditions that customers may negotiate can create confusion as to customer service priority when the control area operator is forced to take action to reduce demand or curtail transactions. The primary responsibility of the control area operator is to maintain the security of the bulk electric system. To carry out this responsibility, operators need flexibility to interrupt supply to customers or curtail wholesale transactions to keep the bulk electric system in balance at all times. With more customers seeking to customize their electricity service, control area operators will need a clear understanding of customer service priorities to be able to take

effective emergency action in a fair and nondiscriminatory way.

Identifying the source of an energy supply can become quite complex for the control area operator as transactions change ownership several times, are subdivided, and recombined. The control area operator must be able to identify points of delivery, intermediaries and points of receipt, and levels of firmness so curtailments can be implemented quickly to safeguard system security while at the same time respecting contract priorities. The NERC Operating Committee is developing policies, which provide clear rules for interchange scheduling, and all market participants must commit to abide by them.

Interconnected Operations Services

In the past, Interconnected Operations Services/Ancillary Services were bundled with energy transactions. Transmission users will soon be able to purchase unbundled services from different or various sources. Administering these services will add additional burdens on system operators. Uniform policies for Interconnected Operations Services do not exist at this time. Without adequate Policies, it is possible that not all energy transactions will include the necessary Interconnected Operations Services. It is important to the reliability of the bulk electric system that common requirements, definitions, standards, and measures for these services be established as quickly as needed. These

will form the basis for future compliance requirements.

Available Transfer Capability

Electronic network posted available transfer capability (ATC) is now being used for reserving transmission service and for scheduling energy transactions on the bulk electric system. FERC's Order 889 now requires that ATC be posted on the Open Access Same-time Information System (OASIS) by November 1, 1996. There are at least two operating concerns regarding ATC. A major concern is the inability of some areas of the bulk electric system to determine the parallel flow impacts of multiple transactions occurring simultaneously in different areas. These parallel flows can cause the ATC in another area to be changed when combined with transactions in that area. Each evaluation of the network's ability to support an additional transaction should take all previously committed transactions into account. Methodologies are needed to determine total path or interface usage in each area due to the parallel path flows of all transactions affecting that area.

A second concern is that ATC may require continuous monitoring and frequent updating by bulk electric system operators for the sake of the market, thereby diverting attention from other important reliability duties. If ATC is to be determined and updated in the control room, sufficient staff must be provided.

Information Sharing

Maintaining reliability of the bulk electric system requires adequate sharing of operating information between all parties responsible for network security. For this to occur in a competitive environment, it is essential that the market function be totally separated from control area operations. In fact, FERC's Order 889 now requires this separation. It is important to note that the market function can be separated from control area operations, but, in the end, generation control cannot be totally separated from transmission control. Generation control is an essential part of controlling transmission flows, providing system restoration following a significant disturbance, and maintaining the availability of shared reserves. Therefore, the operators of any separated functions must share security-related information.

A significant amount of thought and industry task force activity has gone into the development of the user-accessible "front end" of the OASIS, but little coordination has occurred on the control area access and use portion. Adequate operator access must be in place to allow the control areas to utilize OASIS information to the extent needed to ensure reliability.

Maintenance and Reliability

Electric utility restructuring is resulting in some degree of separation of responsibility for generation and transmission. Nevertheless, coordination of generation and transmission maintenance

must continue to occur in order to ensure the ongoing reliability of the bulk electric system.

The high utilization of some transmission facilities could result in reduced opportunities to remove these facilities from service for maintenance. Adequate maintenance will be a key component to maintaining the reliable operation of the transmission system as it becomes more heavily utilized.

There is increased pressure in the industry to reduce maintenance costs in order to become more competitive. If budgets are reduced, it will be important that adequate attention be given to those systems critical to reliability, such as protective relaying and control systems.

NERC policies reflect the need to adequately maintain power system facilities at the level necessary to meet overall system performance standards.

Independent System Operators

The ISO concept is gaining popularity in many areas of NERC, with various models having different ISO functional responsibilities being considered. Although the ISOs that actually become implemented may be significantly different from one another, they will serve to enhance network reliability if they all conform to the same, consistent set of reliability principles — NERC Reliability Policies and Standards. These "Rules of the Road" must be observed by all market par-

ticipants. The functions of the ISO must complement, not conflict with, the roles of control areas, Regional Councils, regional transmission associations, security coordinators, and any other entities formed with security responsibility or oversight. If there is sharing of responsibilities for reliability between control areas, the Regional security coordinators, and the ISOs, there must be clear agreement on the role of each entity and a total commitment to thorough coordination.

Control Performance

Keeping generation and demand in balance and contributing to interconnection frequency control are paramount to reliability. NERC has established control performance standards to provide for the equitable distribution of the responsibility for maintaining this balance among all the control areas. New standards are currently under review. Compliance to these standards continues to be a priority that must be adhered to by all control areas. Noncompliance could lead to a reliability risk in that interconnection frequency could become more erratic and frequency recovery more difficult to coordinate.

System Operator Training, Tools, and Authority

System operators are expected to operate the transmission systems in a safe, reliable, and economic manner. In some cases, special protection systems, adaptive relaying, and operating procedures are being used to increase system capability with-

out adding new transmission facilities. System operators need to understand and be well trained in the use of these devices and techniques. The challenge to the system operator is to determine the *reliable* capability in the system that is available for transactions. In other words, how far can the system be “pushed” and still adhere to NERC and Regional reliability Policies and Standards.

Reliable operation of the bulk electric systems also depends on effective operational planning — planning for the reliable operation of the systems for the upcoming days, weeks, and months. Operational planning models need to take into account those resources that may be capacity limited, energy limited, or that may have special operating characteristics. New patterns of generation that may result from competitive pricing of these resources and the transmission flow patterns that result need to be carefully analyzed in advance to identify any potential conditions under which the reliable operation of the systems may be at risk.

System operators must continue to receive advanced training, have sophisticated tools to effectively monitor and assess the state of the systems, and have clear authority to take timely action to ensure reliability. The Regions and their members need to review the need for tools such as on-line power flow and stability programs and real-time data monitors that can assess primary reliability indicators for system-wide frequency

and voltage performance on a real-time basis and that can record disturbances for effective and timely determination of their cause and impacts. This is especially critical during the period of rapid change the electric industry is facing today. NERC’s System Operator Subcommittee is responsible for NERC Operating Policy 8 — Operating Personnel and Training. It develops various training documents and training aids to assist Regional Councils and their members in ensuring that system operators are well trained and have a thorough understanding of the NERC Policies.

One issue of immediate concern to NERC is how utilities may reorganize to separate their transmission operations and reliability functions from their wholesale electricity merchant functions to comply with FERC Order 889 and to satisfy other business objectives. It is not totally clear what utilities will do to comply with FERC’s Standards of Conduct. However, what is clear is the critical need to continue to have *integrated operational control* of generation *and* transmission to ensure reliability. NERC has several of its subcommittees looking into this issue to make sure that operational control for reliability is not overlooked or compromised.

Voltage and Reactive Issues

While much work has been done recently, voltage collapse continues to be the subject of frequent discussions by utility personnel. Both operations and

planning engineers are taking a great deal of interest in this complex phenomenon. Some systems or areas are experiencing transfer limitations now due to voltage collapse problems and have developed special operating procedures to deal with them. Others are focusing on maintaining an adequate reactive supply to keep voltage levels within desired limits.

What has changed in recent times that has made voltage collapse such a significant issue? One change is the increased use of the transmission system for the transfer of energy from remote generation to load centers. The public does not want generating units in its local areas, which has caused utilities to build generating stations in outlying areas or purchase capacity from remote sources. Furthermore, utilities are loading the transmission systems by transferring large amounts of electricity from Region to Region. They are also using more devices such as special protection systems and shunt capacitors to increase their capability to transfer larger amounts of electricity. Excessive use of shunt capacitors for transmission line reactive compensation can raise the critical voltage into the normal voltage range. Both the East and West Coasts now have areas where voltage stability can limit electricity transfers.

In an effort to shed more light on this emerging issue, the NERC Engineering and Operating Committees jointly directed NERC's Interconnection Dynamics Working Group to re-

view this subject. The recommendations in the August 1991 report of the Task Force called for Regions or their individual utility members to consider:

- Development of training programs for system operators, plant operators, and system planners to increase their awareness of the importance of voltage and reactive scheduling and the interaction between the plants and the system.
- The voltage collapse phenomenon when developing or reviewing Regional and utility planning and operating criteria.
- Development of a program for testing generating units to establish their actual reactive capability range and for enhancing that range by implementing cost-effective measures to remove limitations.
- The need for and implementation of remedial measures to prevent, mitigate, or deal with voltage collapse. Such measures could include: 1) coordination of voltage and reactive scheduling among neighboring utilities and Regions; 2) blocking load tap changers during declining system voltage conditions; and 3) implementation of under voltage load shedding schemes.
- The need for changes to the NERC Operating Guides to reflect voltage collapse issues.
- Working with EPRI, academia, and others to focus in-

dustry efforts toward improved modeling and analyses of the voltage collapse phenomenon. These efforts could include an examination of load modeling practices as they relate to load behavior over a range of system voltages. In particular, the modeling requirements in areas with heavy saturation of air conditioner loads could be reviewed. Also, the modeling requirements and voltage quality needs of modern solid-state controlled loads could be reviewed.

NERC and the Regions will review the recommendations in NERC's 1991 report, *Survey of the Voltage Collapse Phenomenon*, survey member utilities regarding their implementation of these recommendations, and determine if any additional follow-up work is needed to address the voltage collapse issue.

REGIONAL RELIABILITY ASSESSMENTS

The remainder of this report assesses the reliability of the electric generation and transmission systems of the nine Regional Councils and one Affiliate member. Some key information is summarized below.

<u>Region</u>	<u>Annual Net Energy for Load (Thousands of MWh)</u>	<u>Peak Demand (MW)</u>	<u>Planned Capacity Resources (MW)</u>	<u>Capacity Margins (% Planned Capacity Resources)</u>	<u>Transmission 230 kV & Above (Circuit Miles)</u>
1996					
ECAR	519,644	85,643	103,003	16.9	15,953
ERCOT	236,549	44,990	55,074	18.3	6,859
MAAC	242,963	45,224	56,881	20.5	6,931
MAIN	222,834	43,229	52,112	17.0	5,559
MAPP-U.S.	144,758	27,487	32,665	15.9	14,106
MAPP-CANADA (winter)	34,387	6,129	8,063	24.0	5,853
NPCC-U.S.	259,702	48,290	62,368	22.6	6,456
NPCC-CANADA (winter)	327,327	56,901	73,905	23.0	28,608
SERC	753,742	137,434	165,844	17.1	28,608
SPP	297,400	57,951	69,354	16.4	14,503
WSCC-U.S.	612,284	99,612	130,180	23.5	54,807
WSCC-CANADA (winter)	100,281	16,275	19,600	17.0	10,268
U.S.	3,289,876	589,860	727,481	18.9	153,782
CANADA (winter)	461,995	79,305	101,568	21.9	44,729
MEXICO (summer)	5,514	1,142	1,390	17.8	425
ASCC (winter)	3,849	710	1,272	44.2	141
2005					
ECAR	605,289	100,648	115,385	12.8	16,230
ERCOT	289,696	54,443	60,344	9.8	7,479
MAAC	276,054	50,298	62,149	19.1	6,996
MAIN	254,857	48,419	57,318	15.5	5,728
MAPP-U.S.	174,127	32,086	33,188	3.3	14,320
MAPP-CANADA (winter)	37,688	6,684	8,131	17.8	6,339
NPCC-U.S.	286,402	52,747	60,231	12.4	6,618
NPCC-CANADA (winter)	381,210	66,457	76,578	13.2	29,362
SERC	916,778	164,753	191,355	13.9	30,451
SPP	342,029	67,500	77,595	13.0	14,890
WSCC-U.S.	712,894	115,212	134,270	14.2	57,888
WSCC-CANADA (winter)	120,764	19,381	22,342	13.3	10,324
U.S.	3,858,126	686,106	791,835	13.4	160,600
CANADA (winter)	539,662	92,522	107,051	13.6	46,025
MEXICO (summer)	10,906	2,200	2,473	11.0	525
ASCC (winter)	4,631	806	1,320	38.9	141

As the electric industry transitions to a new era of competition and open access, the ECAR membership remains committed to maintaining the reliability of the interconnected bulk electric systems. ECAR is actively addressing the key issues that must be successfully resolved to ensure the transition to the "new world" is accomplished in a way that does not adversely impact reliability.

The bulk electric systems in ECAR will continue to perform well in meeting the forecast demand obligations over a wide range of anticipated system conditions, as long as established operating limits and procedures are followed and proposed projects are completed in a timely manner. In particular, American Electric Power's Wyoming-Cloverdale 765 kV line is needed to guard against potential voltage collapse and resulting cascading failure of the transmission network in southeastern ECAR and with the possibility of cascading into neighboring areas. Currently planned capacity resources will satisfy the Region's criterion for adequate reliability throughout the assessment period provided the average annual generating unit availability is maintained at or about levels experienced in recent years.

Demand and Energy

Throughout the assessment period, the total internal demand of ECAR members is expected to remain summer peaking with a 1.85% average annual growth rate, up from 1.6% forecasted last year. Current resource plans developed by ECAR members project a reliance on direct-controlled and interruptible load management programs of about 3,550 MW; plans also include about 1,100 MW of new noncontrolled programs. With demand-side management included, the ECAR Region's net internal demand is projected to grow at 1.7%, reaching about 101,000 MW in 2005.

Resource Assessment

ECAR members are projecting to add or contract for about 13,500 MW of new capacity, including 2,200 MW of nonutility generation. Only

about 5% of the projected generation additions are reported to be under construction or under contract. Of the new capacity, about 11,700 MW is expected to be combustion turbine-based with about 94% of the new combustion turbine capacity expected to be gas-fired. If capacity reported as "planned" is excluded, capacity margins will be at 4.0% in 2005. As these resource projections evolve, the mix of demand-side programs, nonutility generation, and utility-owned capacity used to meet demand growth may change.

ECAR annually conducts an extensive probabilistic assessment of long-term capacity margin adequacy. It considers the Regional peak demand profile and the generation availability of ECAR members to assess ECAR-wide reliability against a

criterion of one to ten days per year of Dependence on Supplemental Capacity Resources (DSCR). Supplemental capacity resources includes assistance from neighboring Regions, contractually interruptible demands, and direct-controlled load management.

One of the most critical parameters to the adequacy of bulk electric supply in ECAR is generation availability. The 1996 capacity margin assessment determined that the annual generation availability must remain at or above 78% to meet the DSCR criterion throughout the assessment period. For perspective, average annual generation availability in ECAR has been 80.1% over the last ten years and was 81.7% during 1995.

It is believed that the aging of generating equipment will necessitate increased maintenance and lengthened outages. By the year 2005, about 59% of the capacity in ECAR will be 30 or more years old, and about 22% will be 40 or more years old. ECAR members recognize the challenges in maintaining the high levels of generation availability experienced in recent years, but expects to meet them. As margins continue to decline, coordination of maintenance schedules will become more difficult.

Coal, the predominant fuel used within the ECAR Region, is expected to supply about 90% of the total electrical energy requirements during the next ten years. While compliance plans to meet Phase 1 of the Clean

Air Act Amendments of 1990 (CAAA) have been implemented, some uncertainty remains in NO_x regulation compliance. The emissions cap provisions of the CAAA may lead to some generating units becoming energy limited. A utility at or approaching its annual emissions limit may be unable to provide emergency assistance to neighboring utilities.

Transmission Assessment

The transmission networks in ECAR are expected to perform adequately over a wide range of anticipated system conditions, as long as established operating procedures are followed, limitations are observed, and critical facilities are placed in service when required.

Local transmission overloads are possible during some generation and transmission contingencies. However, operating procedures are used by ECAR members to mitigate such overloads. Current plans call for the addition of 294 miles of Extra High Voltage (EHV) transmission lines (230 kV and above) that are expected to enhance and strengthen the bulk transmission network. Included in these planned additions is the American Electric Power (AEP) Wyoming-Cloverdale 765 kV transmission project. This project, originally scheduled for completion in May 1998, and subsequently rescheduled to 2000/01, has recently received a major setback in the ability to construct the project. The U.S. Forest Service, in June 1996, issued a Draft Environmental Impact Statement (DEIS) for

AEP's Wyoming-Cloverdale 765 kV line recommending against the siting of this line through approximately 12 miles of federal lands.

System studies indicate that by the late 1990s transmission facilities in the southeastern part of ECAR could become overloaded under certain circumstances. Should these overload conditions occur, a potential voltage collapse and cascading failure of the transmission network could be precipitated that would affect power supply in southern West Virginia and southwestern Virginia. Should uncontrolled cascading occur, a major blackout affecting southeastern ECAR and possibly neighboring areas could result.

In 1990, AEP proposed the addition of a 115-mile, 765 kV line to connect AEP's Wyoming County, West Virginia substation to AEP's Cloverdale, Virginia substation (near Roanoke). Upon completion, it would provide a substantial increase in the transmission capacity in southeastern ECAR specifically and, in turn, from the Midwest to the East Coast — enough to mitigate transmission constraints for the foreseeable future. The findings of the U.S. Forest Service in its recently issued DEIS raises questions as to whether this project can be constructed.

If the line cannot be built, the ramifications are enormous. Stop gap measures can be employed, but electric service reliability in southeastern ECAR eventually will erode to an unacceptable level. That may re-

sult in the possibility of a major blackout in the southeastern ECAR Region. Because of the historical development of the interconnected power grid and its complex network of facilities, recovery from such a blackout would be extremely difficult and costly.

Operations Assessment

Reliability will continue to be maintained through the use of operating procedures such as the Reliability Coordination Plan (RCP) and the MAIN-ECAR-TVA (MET) Emergency Transmission Loading Relief Procedure.

The RCP is used to resolve line loading problems involving power transfers in eastern ECAR, MAAC, and the VACAR Subregion of SERC to ensure that reliability is maintained. The number of times this procedure has been used in the last few years is lower than prior years because: 1) the installation of 2,300 Mvar of EHV reactive power support has improved the power transfer capability across that part of the transmission network, and 2) the level of power transfers across that area has been reduced from the level seen in previous years. However, the use of this procedure during 1996 has increased significantly over its use in 1995.

The MET Emergency Transmission Loading Relief Procedure is used by systems in ECAR, MAIN, and SERC to maintain reliability during heavy north-to-south electricity transfers similar to those experienced

during the summer of 1993. This procedure utilizes a computerized Data Exchange and Communication System (DECS) to facilitate the quick exchange of relevant operating data, such as line loadings and interchange schedules, whenever a problem develops or is anticipated by any MET company. MAIN, TVA, and each control area in ECAR have remote terminals on DECS that they can use to initiate data exchange.

Other ECAR Activities

The Energy Policy Act of 1992 is the principle driver of the significant changes occurring in the electric industry as evidenced by FERC's final orders on open access, OASIS, and standards of conduct; various industry restructuring initiatives under consideration in several states and the U.S. Congress; and NERC's "Strategic Initiatives."

Like everyone involved in our changing industry, the ECAR membership is addressing the new challenges it faces and is making necessary changes to the way ECAR functions to be responsive to the realities of the "new world." Here is a brief summary of some key ECAR activities.

■ **ECAR Structure and Governance**

As ECAR considers the basic question of "How do we continue to be an effective reliability-focused organization in the new era of competition and open access?,"

ECAR is reviewing its organizational structure, governance provisions, and technical documents and guides. Some changes have already been made in these areas and others are in the works.

■ **Membership Growth**

In 1994/95, ECAR modified its Membership Requirements to allow and encourage broader participation in ECAR activities by IPPs, power marketers, and full members of other Reliability Councils. ECAR's Associate Membership has grown from four at year-end 1993 to 24 as of August 1996. Membership growth is expected to continue for some time.

■ **OASIS Implementation**

ECAR is participating in the multiregional collaborative effort known in the industry as the "JTSIN Group." Through this joint effort, ECAR plans to implement the "Phase 1" FERC OASIS requirements as set forth in FERC Order No. 889 in a fully compliant, timely, and cost-effective manner. ECAR will install a Regional OASIS node at the ECAR office for use by all ECAR transmission provider members.

■ **Security Process**

In concert with the ongoing NERC security process initiative, ECAR is developing a security plan for the Region. ECAR expects to have the

plan completed by December 1996.

■ **Reserve Sharing**

As part of the security process initiative, ECAR is developing a formal reserve sharing mechanism similar to that now in use in the Southwest Power Pool.

■ **ATC**

In close coordination with the OASIS and security process initiatives, ECAR is developing its plan to respond to the NERC *Available Transfer Capability Definitions and Determination* report and recommendations.

The East Central Area Reliability Coordination Agreement (ECAR) membership currently consists of 29 Full Members and 24 Associate Members serving either all or parts of the states of Michigan, Indiana, Kentucky, Ohio, Virginia, West Virginia, Pennsylvania, Maryland, and Tennessee.

Future resource reliability in ERCOT will become dependent on load serving entities arranging for needed resource commitments or additions in a timely manner.

The bulk transmission system is adequate and will continue to meet ERCOT Reliability Criteria while a new transmission planning and acquisition process is being determined and put in place in ERCOT.

Demand and Energy

The average annual growth rate in ERCOT's summer peak demand is projected to be 2.0% for the 1996–2005 period. This is below last year's forecast of 2.1%. The expected winter peak demand growth of 2.3% is down from last year's estimate of 2.5%. The projected average annual growth for energy of 2.3% is above last year's estimate of 2.1%.

Resource Assessment

Prior to this year, most of ERCOT's planned and actual capacity additions have been utility-owned. This year, ERCOT plans show a higher percentage of independent power producer (IPP) capacity additions during the next ten years than utility-owned additions. Significant IPP additions are shown beginning in 2000 and will require future bidding and contract negotiation. Therefore, these resources are currently unidentified and uncommitted.

ERCOT's capacity reliability criteria is 15% reserve margin (13% capacity margin). This year's planned capacity indicates reserve margins of 22.4% (18.3% capacity margin) in 1996 dropping to 10.8% (9.8% capacity margin) in 2005, with

15% reserve margin or above through 1999. The capacity shown through 1999 is existing capacity and the reserve is adequate. The drop below 15% in 2000 does not represent a decline in reliability. It is due to the fact that in the competitive environment, load serving entities may not identify future capacity additions until they are actually committed for.

ERCOT should continue to have adequate resource reliability as long as the load serving entities allow sufficient lead time in their acquisition process to ensure the capacity is available when needed. With most of these additions being contract purchases or new capacity based on combustion turbine additions, a three-year lead time is sufficient.

Transmission Assessment

Recent Texas Public Utility Commission (PUC) rulemaking requires that an Independent System Operator (ISO) be established in ERCOT with one of its duties being regional transmission planning. The rulemaking leaves responsibility for new transmission construction unclear until the new process is more clearly defined.

No 345 kV transmission is being constructed in ERCOT at this time, but studies indicate that the current transmission system is adequate and will continue to meet ERCOT Reliability Criteria while a new transmission planning and acquisition process is being determined and put in place.

Operations Assessment

For the past year, ERCOT has been studying merging its two security centers into one independent security center to provide for comparability. As previously mentioned, recent Texas PUC rulemaking has established the requirement for an ISO in ERCOT. This ISO is also charged with the responsibility for performing the security function and facilitating the efficient use of the transmission system, including the operation of an ERCOT TSIN. ERCOT will integrate the independent security center into the ISO. This integrated operation should provide for maximum reliability of the bulk power system. An ERCOT task force is currently revising the ERCOT operating guides to ensure compatibility with the new security structure.

Reliability Issues

During ERCOT's transition to an ISO structure for security and transmission access, all participants must work together to maintain reliability during the transition and ensure that all new operating and planning procedures adopted maintain adequate provisions for the future reliability of the bulk electric system.

The major portion of planned new resources in ERCOT continue to be natural gas fired. Very cold weather in the Region in February of 1996 resulted in substantial natural gas curtailments for electric generation and significant use of back-up fuel oil. ERCOT resource operators must continue to monitor the availability and firmness of their natural gas supplies and provide adequate back-up fuel reserves to ensure the continued availability of the generation during severe weather.

The Electric Reliability Council of Texas (ERCOT) is comprised of 16 municipalities, 46 cooperatives, six investor-owned utilities, two state river authorities, five nonutility generators, and 15 power marketers. ERCOT members serve over 12 million customers (and approximately 200,000 square miles or 73% of Texas) and account for 56,000 MW of generating capacity and 32,000 miles of transmission lines.

MAAC will have adequate generation and transmission capacity over the ten-year forecast period. Committed capacity meets targeted reserve margins through the year 2003. Maintaining system reliability in the new competitive marketplace is being addressed during the PJM restructuring.

Demand and Energy

Net peak demand and energy forecasts for 1996 are similar to the 1995 forecasts. The net peak demand growth rate increases from 1.3 to 1.4% and the energy growth rate remains 1.5%.

Resource Assessment

The MAAC forecast shows adequate capacity to meet the Region's reliability goals throughout the forecast period. Net capacity resources are projected to increase by 5,000 MW from 1996 to 2005. While only a small portion of the increase is currently shown as fueled by natural gas, expectations are that a major portion of this new capacity will be gas fired as the capacity is committed. In recent years, the trend for outage rates in MAAC has been down despite an increasing average age of generating units. This reflects good maintenance practices and should prevent the increasing age of generators from becoming a reliability problem. MAAC reliability studies confirm that MAAC can meet its reliability criteria with a reserve margin requirement of 20% in 1998.

The resource planning process is being complicated by longer lead times for transmission additions compared to generation, uncertainty of generation supply

sources, and uncertainty of who will supply wholesale customers after current power contracts expire. As a result, MAAC capacity forecasts show increasing amounts of undetermined generation in the later years. The Regional reserve level without this undetermined generation first drops below the targeted reserve margin of 20% in 2004. There is adequate lead time to commit undetermined resources as needed to meet MAAC reserve requirements.

Transmission Assessment

The MAAC Regional transmission system, with its ties to the Eastern Interconnection, is adequate for reliable operation under non-simultaneous emergency assistance transfer conditions. It is also likely that there is enough operating flexibility in the power system to maintain reliability even during possible simultaneous emergency electricity transfers. Increasing competition in the electric utility industry will put more pressure on the transmission system as new transactions are desired. The reliability of subareas of MAAC will be closely monitored to ensure that the import capabilities and internal generation levels of subareas do not fall below levels required for MAAC to meet its reliability criteria. A new 500–230 kV substation is expected to rein-

force supply to eastern PJM in 1997.

Operations Assessment

MAAC recognizes that increasing competition in the wholesale electricity market has increased both the number of market participants and the number of transactions. To meet the operational needs of this expanded market, PJM and other control areas must develop additional rules and procedures for communications and data reporting necessary to ensure reliable operation of the bulk electric system.

The PJM companies have filed two separate integrated packages of proposed agreements that represent a comprehensive restructuring of the PJM Pool. Both of these filings restructure the PJM Interconnection Association into an Independent System Operator (ISO). In both, the ISO will be responsible for the daily management and administration of Pool operations, the energy market, and the Regional transmission network. Included are the administration of pool-wide, unbundled, non-discriminatory transmission services and tariffs, as well as an enhanced pool-wide planning process.

There has been an increasing trend in Minimum Generation Emergencies declared by PJM (up from 48 occurrences during 1994 to 66 occurrences during 1995). This trend will be monitored to determine if load-following capability is becoming

inadequate during Minimum Generation Emergency conditions.

Reliability Issues

There are several areas of concern in MAAC related to the advent of greater customer supply choices that are being addressed as part of the ISO to ensure that reliability can be maintained.

To improve the ability to plan for generation and transmission needs, the ISO will incorporate input from MAAC members and associates. Load-serving entities will, as a minimum, need to provisionally indicate where their generation needs will be supplied from with sufficient lead time to allow for the planning and installation of any needed transmission.

Other areas of concern, which MAAC shares with other Regions, include the ability to plan and install new generation facilities faster than new transmission can be installed, as well as possible double-counting of capacity if an aggregation of nonfirm capacity contracts are repackaged as firm capacity.

Cooperation among all participants in the Region will be essential in order to develop rules and procedures for the data exchange and electric system planning processes that will be necessary to ensure reliability in the MAAC Region.

The Mid-Atlantic Area Council (MAAC) Region consists of 18 Full Members and 20 Associate Members serving over 22 million people in a 48,700 square mile area. The Region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey, and Maryland, and a small portion of Virginia.

MAIN expects to have adequate generating capacity reserves and transmission system capability to meet its reliability criteria throughout the 1996–2005 period.

Demand and Energy

Summer peak demand for the 1996–2005 period is forecast to increase at an average annual rate of 1.75%, slightly above last year's projected rate. The actual MAIN 1995 demand of 45,782 MW was about 4.15% above last year's forecast.

The projected electrical energy average annual growth rate for 1996–2005 is 1.69%, slightly above last year's forecast rate. Actual electrical energy use in MAIN was 224,380 GWh, about 3.66% above forecast.

Resource Assessment

MAIN utilities expect to add over 4,000 MW of net production capacity resources and about 1,500 MW of load management and interruptible demand resources in the next ten years. Reserve margins for MAIN as a whole are projected to remain in or above the recommended range of 18 to 22% (15 to 18% capacity margin).

Supply adequacy in MAIN is assessed using loss of load probability (LOLP) analysis. Considering load forecast uncertainty due to all factors, including weather and diversity among Regions, MAIN will have adequate generating capacity to meet its one day in ten years criterion (0.1 day or less per year LOLP) throughout the entire study period, based on

the projected yearly reserve margins for MAIN.

Transmission Assessment

The long-term analysis of transmission in MAIN indicates that the MAIN transmission system is expected to be adequate to support reliable operations. Constrained interfaces reported in 1996 have been relieved with the exception of the ECAR to Northern Illinois interfaces, which continues to be assessed as inadequate to support emergency imports required by ComEd.

The Burnham-Taylor 345 kV line, which had been delayed for several years, was completed in March of 1996. The line serves the downtown Chicago area.

Operations Assessment

The summer of 1995 was one of the Region's hottest ever, and MAIN set an all-time peak in July. The record heat and humidity was very demanding on the Region's bulk electric system, and numerous transmission emergencies were declared through the period. Regional members exercised numerous relief procedures that included voltage reductions, curtailments of interruptible demand, public appeals for reduced customer usage, and electricity transfer reductions via formal line-loading relief procedures.

MAIN Guide 1C (line-loading relief) was rewritten to include reductions in interchange based on priority levels related to transmission service arrangements. This revision increased the number of priority levels from four to seven.

Practical, timely, inter-regional line loading relief implementation remains a problem. Difficulties experienced in 1995 in identifying the transactions causing parallel path flow reliability problems continue in 1996. Information on transactions and unusual conditions must often be gathered "manually" through repeated telephone contacts. This emphasizes the criticality of the reliability infrastructure reforms recommended in the NERC Security Process Task Force report, which was approved by the NERC Board of Trustees in May 1996.

During 1995, MAIN certified all control areas in the Region with the implementation of MAIN Guide 9. The certification process included visits to the control areas by certification teams, consisting of representatives from other control areas within the Region, and from the MAIN Coordination Center. The teams reviewed operating procedures and verified the responses to the MAIN Control Area Certification Review Questionnaire. Six control areas were certified unconditionally, while six others were conditionally certified based on commitments by their parties to make certain compliance provisions.

*The Mid-America
Interconnected Network
(MAIN) consists of 14 Regular,
12 Associate, and five Affiliate
Members. MAIN is a summer
peaking Region serving a popu-
lation of 19 million in a geo-
graphic area of 120,000 square
miles encompassing Illinois, the
eastern third of Missouri, the
eastern two-thirds of Wisconsin,
and most of the upper peninsula
of Michigan.*

Generation and transmission resources will be adequate for the 1996–2005 period provided short lead time generation will be added toward the end of the period. MAPP-U.S. utilities plan to meet additional capacity needs mainly by installing combustion turbines, uprating existing units, and purchasing accredited generation from others. MAPP-Canada utilities will install a small amount of combustion turbine capacity at the end of the period.

MAPP members approved the Restated MAPP Agreement changing the structure of the pool. The new structure, if approved by FERC, will be an umbrella organization encompassing three functions: a NERC Regional Council, a regional transmission group (RTG), and a power and energy market. Membership will be open to any entity eligible for a Section 211 wheeling order under the Federal Power Act.

MAPP is continuing the development of a Regional Security Center to maintain reliability in the new competitive power industry. A separate Regional Open Access Same-time Information System (OASIS) is also being developed to meet FERC requirements.

Demand and Energy

Demand and energy usage continue to increase throughout the MAPP Region at a moderate rate. The peak demand for MAPP-U.S. is projected to increase at an annual growth rate of 1.9% for the reporting period, and for MAPP-Canada at a rate of 0.8%. This represents a slight increase in the MAPP-U.S. growth rate and a slight decrease for the MAPP-Canada growth rate. Use of electrical energy is expected to increase at a rate of 2.1% per year in MAPP-U.S. and 1.0% in MAPP-Canada, for a composite in the Region of 1.9% over the reporting period.

Resource Assessment

The required 15% minimum planning reserve margin above noncoincident demand will not be maintained by MAPP-U.S. through 2005 based on commit-

ted and proposed generation additions. The MAPP-U.S. reserve margin drops to 12.7% in 2002, 10.8% in 2003, 9.0% in 2004, and 5.4% in 2005. All MAPP members are committed to installing or acquiring sufficient capacity to maintain their required reserve margin. Some members are becoming more reluctant to identify specific resource additions (generator type, size, and location) until granted authorization to construct or enter into a purchase agreement. However, power resources in MAPP-U.S. are judged to be adequate over the 1996–2005 reporting period.

In MAPP-Canada, minimum planning reserve margins will be maintained throughout the reporting period by existing generation.

Transmission Assessment

Transmission capacity is expected to remain adequate over the reporting period. MAPP-U.S. utilities plan to add 550 miles of transmission at 161 kV and above during the reporting period. Approximately 120 miles will be conversion of existing 115 kV lines to 161 kV with one upgrade strengthening the Minnesota-Wisconsin interface between MAPP and MAIN. A new interconnection between MAPP and MAIN is planned for the Burlington, Iowa area for the 1997/98 time period. One very important addition to the Region is the Pauline-Mark Moore 345 kV line in south central Nebraska. This 99 mile line will relieve loading and stability constraints in the area. The line was placed in service on April 22, 1996. MAPP-Canada plans on adding 485 miles of new 230 kV transmission.

The present trend of increased transmission loading is expected to continue through the reporting period. A more heavily utilized transmission system will result in reduced transmission margins, and voltage problems will become more prevalent. Transfer capability in most directions across MAPP is considered adequate into the future, but requests for transmission access may initiate improvements to the heavily utilized eastern boundary of MAPP. The impacts of nonutility generation and transmission access is still largely unknown.

Operations Assessment

MAPP has given top priority to the development of a Regional security center. Significant progress has been made with the completion of the system model and implementation of the Operating Reserve Monitor. The Reserve Monitor checks pool generation reserves for the current and next hour. This function will be expanded to also include next day reserves. The completion of the network model is the first step in developing the Network Analysis Applications, which include State Estimator, Operator Power Flow, and Contingency Analysis.

ECAR, MAPP, MAIN, NEPOOL (Subregion of NPCC), VACAR (Subregion of SERC), and SPP are jointly developing an interregional Open Access Same-time Information System (OASIS) to implement FERC Order 889. This system will provide a common basis for the determination and posting of available transmission capability (ATC) to facilitate the inter-regional transfer of energy. This OASIS will have a common PC-based platform, provide backup for each of the other Regions, and will be funded through user fees.

Adherence to NERC and MAPP reliability criteria and standards will be considered essential in the emerging competitive industry.

The Mid-Continent Area Power Pool (MAPP) membership includes 70 utility and nonutility systems. The 28 participants consist of eight municipal systems, eight investor-owned systems, eight generation and transmission cooperatives, three public power districts, and one federal agency. The 42 Associate participants consist of two Canadian Crown Corporations, 14 municipal systems, six investor-owned systems, 19 power marketers, and one independent power producer. The MAPP Region covers all or portions of the states of Iowa, Minnesota, Nebraska, North Dakota, Illinois, Michigan, Montana, South Dakota, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area served is 890,000 square miles with a population of 16 million.

In the near term, the availability of operable generating capacity in New England is a concern. In the long term, each of the five NPCC Areas have plans for adequate capacity resources for the forecast period or is considering various options for the additional resources that may be required. The existing interconnected bulk electric transmission systems in New England, New York, Ontario, New Brunswick, and Nova Scotia meet NPCC Criteria, and are expected to continue to do so throughout the forecast period. With the completion of an extensive enhancement program, Hydro-Québec's bulk power system will be brought into full conformance with all NPCC Criteria by the 1996/97 winter peak period.

Demand and Energy

The average annual growth rate forecast for the summer peak demand for NPCC-U.S. is 1.0%, which is slightly higher than last year's 0.9% forecast. The projected summer peak demand for NPCC-U.S. for 2004, the last common year of the two most recent ten-year forecasts, is about 650 MW higher than last year's forecast. In addition, the projected annual electrical energy growth rate of 1% is the same as last year's.

The average annual growth rate for the winter peak demand for NPCC-Canada is 1.7%, which is a little lower than last year's 1.8% forecast. The projected winter peak demand of NPCC-Canada for 2004/05 is about 2,000 MW less than last year's forecast. The projected annual electrical energy growth rate of 1.7% is less than last year's forecast of 2.0%.

Resource Assessment

In the near term, the availability of operable capacity in New England may be lower than required to meet all customer demands because of the shutdown

of the three Millstone Nuclear Units (2,630 MW total), Connecticut Yankee Nuclear Unit (580 MW), and the Maine Yankee Nuclear Unit (870 MW).

The return dates of these units are uncertain at this time. Utilities in New England are taking extraordinary measures to maximize available generating capacity during the summer to minimize the impact of these conditions on customers. The New England Power Exchange (NEPEX) is prepared to make normal use of its Operating Procedure No. 4 — Action in a Capacity Deficiency — which includes actions such as voltage reductions and customer appeals to reduce customer use of electricity. NEPEX expects to be able to meet projected peak demands this summer, which are 2.4% above last summer's peak, without having to curtail any firm customer load.

In the longer term, indirect demand-side management (DSM) in New England represents a decrease of about a 2,150 MW in the otherwise expected demand by the end of the year 2005. The resultant

average annual growth rate for 1996 through 2005 is 1.1% for the summer peak demand, 1.2% for the winter peak demand, and 1.3% for energy.

Generating units owned by independent power producers (IPPs) claimed by New England Power Pool participants for capability are estimated to be nearly 2,800 MW by the end of 2005. A firm energy contract for the delivery of seven terawatt-hours (TWh) per year from Hydro-Québec to New England via the Phase II HVDC Interconnection also is in effect until July 2001. These currently committed resources in New England are adequate through the summer of 1999, assuming the unit additions, planned purchases, and estimated capacity from IPP-owned generation are in service and the forecast demands are not exceeded. In addition, the New England Power Pool, through a comprehensive resource adequacy assessment procedure, has identified potential and contingency resources in excess of forecast requirements that could be developed within the required time frame, if needed.

In New York, the peak demands that are forecast for the years 1996–2005 show an average annual growth rate of 0.9%, which is the same as last year's forecast. The forecast net energy for the same ten-year period also shows a growth rate of 0.9% (same as last year's forecast). These forecasts reflect a reduction of 2,870 MW and 10,290 GWh in the otherwise

expected demand and energy by the year 2005 due to indirect DSM programs. Capacity additions in New York include 75 MW from IPP generators, 204 MW from competitive bidding, and 22 MW from utility-owned hydro and wind generators by the year 2005. In addition, New York is planning to retire nearly 500 MW of generation by the year 2005. The New York Power Pool reserve margin will be adequate over the 1996–2003 period. The member systems are considering various options for increasing capacity by 2004.

Ontario Hydro's average annual growth rate for 1996 through 2005 is 1.5% for the winter peak demand, as compared to a rate of 1.6% reported last year. Energy growth is projected at 1.7% for the same period as compared to last year's value of 1.9%. By the winter of 2005/06, generating capacity owned by IPPs is projected to be about 1,500 MW. Future capital expenditures continue to be reviewed with many previously planned capacity additions indefinitely postponed. Ontario Hydro is forecasting adequate levels of resources throughout the reporting period even after mothballing about 4,300 MW of capacity by the end of 1996.

Hydro-Québec's average annual growth rate for 1996 through 2005 is 1.8% for the winter peak, which is slightly less than the 1.9% forecasted last year. The demand for energy will increase at an average annual rate of 1.7% between 1996 and

2005, which is less than the 2.1% projected last year. Industrial interruptible demand will be about 2,080 MW by the end of the forecast period. IPP-owned generating capacity will be about 370 MW in the winter of 1996/97, and is projected to increase to about 500 MW by the winter of 2005/06. Utility-owned generation is projected to increase by about 2,080 MW by the winter of 2005/06, while over 2,900 MW of previously planned generation, including the initiation of the Great Whale project, still is delayed beyond the forecast period.

In the Maritime Area (New Brunswick, Nova Scotia, and Prince Edward Island), indirect DSM initiatives are expected to reduce peak demand by over 250 MW by the end of the forecast period. Taking this reduction into account, the resultant average annual growth in winter peak demand for 1996/97 through 2005/06 is 1.5% and the corresponding growth in energy is 2.1%, the highest in any NPCC Area. Planned utility generating unit additions currently total about 525 MW through the forecast period and about 115 MW is scheduled for retirement. Projected IPP generator additions are estimated to total about 90 MW.

By the year 2005, total contributions for the U.S. Areas of NPCC from the indirect portion of planned DSM programs are expected to be over 5,000 MW or about 1% of the total projected summer peak demand. The dependability of these programs on a long-term basis and

their availability during peak demand periods represent reliability issues, which are being addressed in NPCC's resource adequacy assessments.

For all of NPCC, the actual electrical energy from IPP generators increased by 16% from 1994 to 1995. The increase in energy from IPP generators is, however, expected to level off. For example, the projected average annual increase in the ten year period from 1996 through 2005 is only 1.8%. For NPCC-U.S., IPP generating units have become the second largest source of electricity (behind nuclear).

By the end of the forecast period, gas-fired generation, both utility and nonutility, is projected to supply close to 30% of the electrical energy in NPCC-U.S. The deliverability of large amounts of gas to the northeastern United States is a reliability consideration that must be appropriately managed. On the other hand, it is interesting to note that NPCC's Canadian utilities are not projecting to use any natural gas for electricity generation throughout the forecast period.

Transmission Assessment

The existing interconnected bulk electric transmission systems in New England, New York, Ontario, New Brunswick, and Nova Scotia meet NPCC Criteria and are expected to continue to do so throughout the forecast period.

In the U.S. Areas of NPCC, planned transmission additions

for voltage levels 230 kV and above total about 160 miles, all in New England. In the Canadian Areas of NPCC, planned transmission line additions during the ten-year forecast period for voltage levels 230 kV and above total about 330 miles, all in Ontario Hydro and New Brunswick.

Hydro-Québec joined NPCC in 1981 with the understanding that, although its system did not satisfy all of the provisions of the NPCC Criteria, contingencies on its system would not be allowed to have a significant adverse impact on the other NPCC systems. Hydro-Québec is currently operated within this constraint. NPCC has approved a Hydro-Québec system enhancement plan that brings Hydro-Québec's bulk electric system into full conformance with NPCC planning and operating criteria by the winter 1996/97 peak demand period.

Operations Assessment

Reliable operations within NPCC are achieved through a hierarchical system. Criteria, Guides, and Procedures developed at the NPCC level are expanded and implemented at the Area level by the two U.S. power pools and five Canadian member systems. The Criteria establish the fundamental principles of interconnected operations among the Areas. Specific operating Guidelines and Procedures provide the system operator with detailed instructions to deal with such situations as: depletion of operating reserve, capacity shortfalls, line loading relief, declining voltage, light

load conditions, the consequences of a solar magnetic disturbance, measures to contain the spread of an emergency, and restoration of the system following its loss.

Each of the U.S. pools and Canadian systems operates a centralized control center for economic dispatch, overall system monitoring, and control. Coordination in the daily operation of the bulk electric system is achieved through recognized principles of good electric system operation, communications, and mutual assistance during an emergency. NPCC maintains a standing Working Group on Interpool Computer Network Application, which establishes and maintains an operational data link among the five Areas together with PJM. The New York Power Pool serves as the NPCC node on the NERC Eastern Interconnection Hotline. Further, the NPCC Areas routinely conduct conference calls every week to assess the operating conditions for the coming week, and procedures are in place to initiate emergency conference calls whenever one or more Areas feel it would serve to preclude an emergency.

NPCC is also a party to Inter-Area Coordination Agreements with MAAC and ECAR. Through these and a similar agreement among MAAC, ECAR, and the Virginia-Carolinas (VACAR) Subregion of SERC, studies are regularly conducted among MAAC, ECAR, and NPCC (MEN) and VACAR, ECAR, and MAAC (VEM). All are performed un-

der the auspices of a permanent Joint Interregional Review Committee made up of representatives from ECAR, MAAC, NPCC, and VACAR.

The Northeast Power Coordinating Council (NPCC) represents 23 investor- and publicly-owned utilities as well as six power marketers. The utilities serve about 49 million people in a one-million square mile area, including New York, the six New England states, and the Canadian provinces of Ontario, Québec, New Brunswick, Nova Scotia, and Prince Edward Island.

Planned capacity resources are judged to be adequate to supply the forecast annual summer peak demand growth for the 1996–2005 period. Nearly 90% of the planned capacity additions in the next ten years will be nonbaseload units. SERC's 1996 forecast capacity margins remain at an average of 15%. Each Subregion of SERC has forecast sufficient capacity to meet its criteria.

Transmission system studies show that contractually scheduled capacity transfers and additional emergency transfers among the SERC Subregions and between SERC and other Regions can be accommodated. However, the increased use of the transmission systems for scheduled transactions has resulted in heavy loading on critical lines and limited interregional economy energy transfer capability.

Demand and Energy

SERC's 1995 summer peak demand of 146,569 MW was 10.6% above the 1994 summer peak, and was 10.7% above the forecast. The 1996–2005 forecast average annual growth in summer peak demand was essentially the same as last year's 2.1%. The summer peak demand projected for 2004 (the last common year of the last two forecasts) is 280 MW higher than projected last year.

Annual electric energy usage increased by 5.2% in 1995 versus 1994 and was 1.4% above the forecast. Although forecast growth rates have not varied widely, the starting point has seen considerable movement in an effort to capture short-term trends.

Resource Assessment

Many systems in SERC are planning to install peaking capacity, and nearly 90% of the planned capacity additions in the next ten years will be nonbaseload units. Overall,

SERC capacity resource margins remain at about 15%.

The VACAR Subregion expansion program is primarily combustion turbine, while the Southern and Florida Subregions have a mix of combustion turbine, combined cycle, and IPPs. The TVA Subregion plans indicate undetermined additions reflecting the uncertainty of the future. Net capacity additions within SERC for the 1996–2005 period total 26,990 MW.

Transmission Assessment

SERC systems have coordinated their transmission planning and operations to ensure the continued reliable use and expansion of the transmission network. The existing facilities along with those planned to meet the future reliability needs of SERC will provide economy and emergency transfer capability between SERC and other Regions and among the SERC Subregions. All systems within SERC expect to meet SERC

reliability criteria during the review period.

The existing SERC transmission systems include 20,783 miles of 230 kV and 7,823 miles of 500 kV transmission lines. SERC systems plan to add 1,476 miles of 230 kV and 367 miles of 500 kV lines in the 1996–2005 period.

Operations Assessment

During the summer of 1995, the Southern Subregion again experienced very large and unanticipated amounts of parallel path flows through its system on its Duke Power Company interface. During peak periods for three consecutive summers, large amounts of power flow were recorded on the Duke tie lines, while no transactions were scheduled between Duke and Southern. This parallel path flow appears to be consistent with a 1,500 MW simulated transfer north to south (MAIN to SPP). These heavy flows precluded Southern scheduling imports from Duke.

Series reactors have been installed on the Southern system along the Duke (VACAR) interface to mitigate these parallel path flow problems. Capacitor additions in the MAAC Region near the MAAC-VACAR (SERC)-ECAR interfaces will improve transfer capability between ECAR and VACAR.

The SERC Operating Compliance Subcommittee continues to review SERC member systems' control areas for conformance to established operating guides. An Emergency Communica-

tions Task Force has been established to produce an improved Regional/subregional emergency communications process. The SERC Security Functions Task Force is developing plans to implement a Regional security coordination function.

The Southeastern Electric Reliability Council (SERC) membership includes 41 Member systems and 19 Associate Members located in nine states in the Southeastern United States. SERC, covering an area of 345,650 square miles, is divided into four diverse Subregions that are identified as Florida (the Florida Peninsula), Southern (the geographical area of the Southern electric system), TVA (the Tennessee Valley Authority area), and VACAR (the Virginia-Carolinas area). Total population in the Region is about 45 million.

It is becoming very difficult to assess reliability in the environment of an increasingly competitive marketplace. Future reliability will be highly dependent on the ability of the market to provide the necessary generation resources.

Demand and Energy

SPP is expected to remain a summer peaking Region with annual peak demand and energy growth rates of 1.6 and 1.5%, respectively, over the next ten years. These growth rates are lower than corresponding growth rates of 1.7 and 1.8% projected one year ago and are considerably lower than the ten-year historical growth rates of 2.9 and 2.6% for peak demand and energy, respectively.

Resource Assessment

SPP has a minimum capacity margin criteria of 15.25%. Projected capacity margins are 16.4% in 1996, dropping below the 15.25% criteria by 1999, and dropping further to 13% by the year 2005. The reason the projected margin falls below the criteria margin is because some of the members just do not forecast additions because such additions are unidentified. These members plan to make the necessary additions, but have the philosophy that if the addition is unknown, then there is no need to show it in the expansion plan.

It is becoming very difficult to assess generation reliability in the increasingly competitive marketplace. A considerable portion of the capacity additions that will be needed to meet demand growth are assumed to be purchased from the

marketplace. While economic theory states that the marketplace will meet demands, system operators had difficulty finding access to resources, regardless of price, on several days in 1995. This is occurring more frequently, all while questions on the validity of current capacity margin requirements are being raised. SPP's Criteria Working Group is readdressing appropriate capacity margin levels. Individual company and customer choices on service reliability are appropriate to the extent that these individual choices do not reduce Regional service reliability to an unacceptable level.

In anticipation of a more competitive environment, members are effectively shortening the planning horizon because they are focusing more on the short-term (two to five years) instead of two to ten years. This means there will be a strong dependence on new gas-fired generation for a Region that is already heavily dependent on natural gas. The Region realizes that much of the natural gas supply will be "nonfirm" in nature and such nonfirmness needs to be factored into reliability analyses.

Recent results from probabilistic analyses show that adequate capacity margin for SPP is very sensitive to small changes in

unit availability, emphasizing the need for reliable units.

Transmission Assessment

No transmission facilities of Regional significance are planned for the bulk transmission system over the next ten years. The planned facilities primarily benefit local areas and have little benefit to subregional or Regional transfer capability. The second High Voltage Direct Current tie to ERCOT went into service during 1995 adding 600 MW to the already existing 220 MW of transfer capability between ERCOT and SPP.

Open access is forcing the industry to deal with issues such as parallel path flow compensation, line loading relief procedures, consistent determination of available transfer capability, and standard terms and conditions for transmission service. All of these issues require a combined rather than an individual approach. Cooperation and coordination must rise above competitive pressure.

Operations Assessment

SPP's unique operating reserve criteria establishes procedures for automatic sharing of reserve for recovery from generating unit losses. Notification of contingencies is quickly distributed to neighboring control areas by a high-speed communications network. Regardless of the magnitude or location, all available reserve in the Region is quickly made available where it is needed. Recovery from unit losses is accomplished more quickly by many control areas promptly scheduling assistance.

Since implementation three years ago, members call on assistance 1.3 times per day on the average. During the last half of 1995, the daily average was over three. This process of automatically sharing reserves has been so successful and useful, SPP is promoting interregional sharing of reserve.

Southwest Power Pool (SPP) is a voluntary association of 53 electric systems located in all or parts of Arkansas, Louisiana, Mississippi, Missouri, Kansas, Oklahoma, Texas, and New Mexico. SPP currently serves more than 6.6 million customers and covers a geographic area of 500,000 square miles with a population of over 25 million.

Capacity margins and fuel supplies are projected to be adequate throughout the Region for the assessment period. The results of recent system disturbances having Region-wide impact and follow-up technical studies to assess the unusual operating conditions during which the disturbances occurred, have heightened WSCC's concern regarding the potential for voltage instability in some areas. As a result, the WSCC members have intensified focus on the voltage stability issue and mitigating measures to ensure reliability throughout the Region. Other issues that continue to receive significant consideration are the uncertainty associated with competition and new industry structures, and the delicate balance between reliability and the economics of competition.

The Western Systems Coordinating Council's (WSCC) outlook regarding the reliability of the interconnected electric system in the West is presented below for each of the four major areas that comprise the Western Interconnection — Northwest Power Pool Area, Rocky Mountain Power Area, Arizona-New Mexico Power Area, and California-Southern Nevada Power Area.

In the following text, several issues are mentioned that could impact the preservation of reliability to varying degrees:

- unusual operating conditions and potential voltage instability,
- competition and increasing pressures to reduce costs,
- changes in the structure of the electric industry, and
- uncertainty associated with competition and change.

Through active participation in the Regional Councils, such as WSCC, individual member par-

ticipants are able to properly manage these issues and maintain a balance between reliability and the economic pressures of competition. WSCC is an open forum for all entities that have a stake in the planning and operation of the interconnected electric system in western North America enabling them to actively share in the responsibility of maintaining this essential balance.

Due to the recent disturbances, the western utilities have implemented the following measures to minimize the potential for future disturbances under unusual operating conditions and maintain reliability of the WSCC Regional transmission system.

- Power flows from the Pacific Northwest to California have been limited pending further study and review of operating conditions.
- Tree trimming programs are being reviewed to minimize outages.

- WSCC will assess voltage support capability of the Northwest area and other areas, as appropriate.

Northwest Power Pool Area

The Northwest Power Pool (NWPP) Area is comprised of the states of Washington, Oregon, Idaho, and Utah; the Canadian provinces of British Columbia and Alberta, and portions of Montana, Wyoming, Nevada, and California. Over the period from 1995 through 2005, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 1.2 and 1.9%. Generating capacity margins for this winter peaking area range between 3 and 10% for the next ten years.

During the winter of 1995/96, the Pacific Northwest experienced the highest water year in the past ten years, resulting in surplus power sales and low energy prices. The months of November, December, January, and February experienced average stream flows on the Columbia River system of 180%, 267%, 169%, and 286% of median. The November, December, and February stream flow levels were the highest monthly stream flows in the 67 years of record keeping. During the first ten days of February, heavy rains, mild weather, and melting snowpack combined to swell rivers above their banks and caused the worst flooding in three decades throughout Oregon, Washington, northern Idaho, and western Montana.

Transmission planning engineers continue to monitor the reliability of service to the Puget Sound and Portland demand centers, particularly regarding the potential for voltage collapse during critical winter peak demand conditions. The situation has been alleviated temporarily by the addition of shunt reactive devices and some substation additions near the centers. In addition, undervoltage load shedding relays have been installed in the Puget Sound area and are being installed in the Portland area.

Canada

On January 1, 1996, Alberta's Electric Utilities Act took effect, changing the operation of the electric industry in Alberta for 1996 and beyond. All generation in the province is now supplied into the power pool of Alberta, which matches demand with lowest cost generation to establish an hourly pool price. Any generator or importer in Alberta can sell into the pool, while entitled distributors and exporters buy from the pool. All physical transactions (the delivery of electric energy) must be arranged through the pool. Financial transactions, such as commercial contracts that hedge against the pool price, are permitted.

The transmission system in Alberta is operated by a Transmission Administrator, which, for 1996, is the Grid Company (GridCo) of Alberta, Inc. GridCo is a joint venture between TransAlta Utilities Corporation, Alberta Power Ltd., Edmonton Power, and the City

of Calgary. Transmission service remains a regulated monopoly and is operated as a province-wide system with all customers in Alberta paying the same rate.

The Act establishes six "entitled distributors" — TransAlta Utilities Corporation, Alberta Power Ltd., Edmonton Power, and the Cities of Calgary, Lethbridge, and Red Deer. The distributors are obligated to pay the fixed costs of existing generating units and, in return, are entitled to a certain amount of energy at a price approved by the Electric Utility Board. The distributors have the obligation to serve customers and will be responsible for arranging new contracts to meet the demand growth as existing plants are retired from service. Because there is no direct power purchase between distributors and generators, these contracts will take the form of a guarantee by the generator of a price for energy to the distributor.

British Columbia Hydro and Power Authority (BCHA) is the first electric system in Canada to offer open access wholesale transmission services on a transmission system. These open access services have received interim approval from the British Columbia Utilities Commission, effective on January 31, 1996. BCHA has also filed its tariff for wholesale transmission services with Northwest Regional Transmission Association (NRTA) and Western Regional Transmission Association (WRTA). To support these transmission services, BCHA is

selling associated ancillary services.

Rocky Mountain Power Area
The Rocky Mountain Power Area (RMPA) consists of Colorado, eastern Wyoming, and portions of western Nebraska and South Dakota. The RMPA may experience its annual peak demand in either the summer or winter season due to variations in weather. Over the period from 1995 through 2005, peak demand and annual energy requirements are projected to grow at a 1.7% annual compound rate. Summer generating capacity margins range between 23 and 26% for the next ten years.

Generating capacity within the Area remains surplus to the RMPA's near-term peak demand requirements. During the 1996 through 2000 period, approximately 1,100 MW to 1,300 MW of surplus generating capacity is included in the Area's planned resources. This surplus includes the planned addition of 858 MW of gas-fired combustion turbines, cogeneration, and combined-cycle units.

Public Service Company of Colorado is repowering the former nuclear generation plant at Fort St. Vrain. The current schedule is to install 130 MW of gas-fired generation in 1996, followed by additional blocks in the next five years for a total of 685 MW. The Fort Lupton-Cherokee 230 kV line in the Area north of Denver was energized in 1995 to support this generation.

Black Hills Power and Light Company (BHPL) placed into commercial operation during 1995 the 80 MW coal-fired Neil Simpson Unit No. 6 at the Wyodak Coal Mine near Gillette, Wyoming. In the same general area of northeast Wyoming and western South Dakota, BHPL and Basin Electric Power Cooperative are constructing a 230 kV line connecting Yellow Creek to Osage, to be completed in late 1996. The purpose of this line is to improve the reliability and load serving capability of the transmission system supporting this geographic area.

Public Service Company of Colorado and Southwestern Public Service Company, headquartered in Amarillo, Texas, have announced plans to merge. Southwestern Public Service is in the Southwest Power Pool in the Eastern Interconnection. The two companies plan to construct a transmission line connecting their respective systems through an ac-dc-ac converter station. The transmission line and converter station are in the preliminary planning phases to determine desirable terminal locations.

WestPlains Energy is planning to construct a 200 MW combined-cycle power plant in Pueblo, Colorado. The unit is scheduled for completion in December 1998. The generation is slated to serve the Pueblo area.

With the exception of the dc interconnection with SPP mentioned above, no projects are

planned to increase the transfer capability between the RMPA and outside areas. The transmission additions internal to the area are intended to improve load serving capability or support generation additions. No major lines are planned to improve intraregional transfer capability. However, the major projects completed in recent years enable the existing transmission system to reliably support forecast demands while providing sufficient transfer capability to neighboring Regions.

Member systems have traditionally placed great emphasis on coordinated and regional transmission planning. Most Colorado member systems are signatories to the Transmission Access Principles, which predate the FERC initiatives toward open access but include most of the same concepts. Some member systems are signatories to WRTA, which, in addition to WSCC, is also promoting coordinated planning. The participants in the area emphasize the importance of coordinated planning in an era of increasing competition to maintain a reliable transmission system.

Arizona-New Mexico Power Area

The Arizona-New Mexico Power Area consists of Arizona, most of New Mexico, the western-most part of Texas, and a portion of southeastern California. Over the period from 1995 through 2005, peak demand and annual energy are projected to grow at respective annual compound rates of 1.9

and 2.3%. Generating capacity margins for this summer peaking area range between 7 and 16% for the next ten years.

Competition is affecting operation and expansion plans. The U.S. Energy Policy Act of 1992 (EPACT) has resulted in effects ranging from federal government entities seeking competitive bids for the sale of federal power agencies to cities entertaining the idea of municipalization. Legislation has been proposed that would allow retail customers to choose their electric supplier. One city in New Mexico has issued bonds to finance the takeover of its electric distribution system.

With increasing competition, members are taking steps to secure their financial future at a time when several members continue to struggle with financial difficulties. Capital expenditures and operation and maintenance expenditures are being minimized. Some generation facilities have been sold to companies outside the Area and additional sales could occur. WSCC members within the Area are concerned that the uncertainty retail wheeling legislation adds to the planning process will adversely impact reliability. These issues will have to be carefully managed to maintain an adequate level of reliability.

Actions taken to protect the environment also are altering electric system operations and plans. An environmental issue of local concern is the impact of the Glen Canyon hydroelectric

plant operation on the local ecology. Currently, the Glen Canyon generation constraint ranges from 300 to 500 MW. This may reduce Western Area Power Administration's hydroelectric energy allocations in the ten-year time frame. A 345 kV transmission line in northern New Mexico has recently been canceled due to an unfavorable ruling from the New Mexico Public Utilities Commission resulting primarily from environmental opposition. In the near-term, significant amounts of shunt capacitors and series compensation have been and are being installed in order to preserve reliability in the area.

Many southwestern systems have joined or have become correspondents to the Southwestern Regional Transmission Association (SWRTA), a regional transmission group. The group will provide subregional planning to accommodate wheeling requests resulting from EPACT. The SWRTA bylaws have been approved by FERC, and a Planning Committee has been formed. This Committee is working on implementing transmission access requirements associated with EPACT.

The following transmission projects are in various stages of development to increase bulk electricity transfer capability and to improve system reliability.

- A 500 kV line from Phoenix to Las Vegas (rated at 1,300 MW) was placed in service in April 1996.

- A 500/230 kV interconnection in north-central Arizona is scheduled for service in 1996.
- A 500 kV line from the Four Corners area to Las Vegas, Nevada (rated at 1,200 MW) is planned and scheduled for service in December 2000.

California-Southern Nevada Power Area

The California-Southern Nevada Power Area encompasses most of California, southern Nevada, and a portion of Baja California Norte, Mexico. Restructuring of the electric industry in California in 1998 and beyond adds much uncertainty to future predictions of generating capacity, energy production by independent power producers (IPPs), and effects of customer energy efficiency/demand-side management programs. Recognizing future forecast uncertainty, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 1.4 and 2.2% from 1995 through 2005. Projected generating capacity margins range between 20 and 23% for the next ten years.

IPPs represent 14.1% of the area's existing installed generating capacity and are forecast to account for 19.2% of the area's net generating capacity additions over the next ten years. By 1997, IPPs are projected to comprise 14.7% of the area's total generating capacity.

The southern California transmission system has been

strengthened to maintain reliability and increase bulk electricity transfers with other areas. An additional 500 kV line between the Las Vegas area and the Los Angeles area, the Mead-Adelanto 500 kV line, was placed in operation in April 1996.

The California Public Utilities Commission (CPUC) issued a decision on restructuring the electric power industry on December 20, 1995 that will have a profound impact on the operation of the three California investor-owned utilities (IOUs) and the way their customers procure energy. The decision is designed to lower energy prices by transforming the existing regulated utility industry into a largely unregulated competitive electricity market while maintaining the reliability of the electric power system.

The CPUC decision requires that by January 1, 1998, the three IOUs (Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDGE)) will have to separate their generation, transmission, and distribution segments into separate business functions. A date of January 1, 2003 was set as a deadline for a fully competitive retail market.

Under the restructuring, an Independent System Operator (ISO) and a power exchange (PX) will be established. The ISO will be in charge of operating the transmission system, maintaining reliable control area

operation, managing transmission congestion constraints, ensuring comparable treatment for grid users, and coordinating real-time generation, demand, and ancillary services for the combined control areas of PG&E, SCE, and SDGE, covering most of the state of California. The PX will function as the spot market for suppliers to bid on generation and for customers to bid on demand, establishing the market clearing price. PG&E, SCE, and SDGE will be required to sell their generation output into the PX for the first five years, in decreasing amounts as a function of the amount of generation divested. The utilities' regulated distribution retailers are expected to buy all, or nearly all, of their supplies from the PX.

Capital and construction costs previously incurred for facilities approved by the CPUC on the customers' behalf will be fully recovered. Recovery will be achieved by establishment of a competition transition charge to be paid by all customers.

By 2003, customers will be able to continue to buy electricity from their local regulated distribution retailer, they may elect to buy directly from the PX, or they may elect to enter into separate contracts with any supplier. The direct access option, known as "retail wheeling," will be phased in over a five-year period (1998–2003), or sooner if practical, for all customers.

Work has proceeded to develop the specific details needed to implement the restructuring de-

cision. The California IOUs filed an application with FERC and the CPUC on April 29, 1996, providing details of the proposed ISO and PX formation. The IOUs and other interested parties have been working together cooperatively to implement the industry restructuring decision in a way that will benefit all participants and maintain safe and reliable electric service to customers.

Western Systems Coordinating Council (WSCC), with 77 member systems and 14 Affiliates, encompasses approximately 1.8 million square miles of territory in 14 western states, two Canadian provinces, and a portion of Baja California Norte, Mexico. The Region is characterized by extremes in population and demand densities, in addition to long distances between demand centers and electric generation sources. The Region is subdivided into four areas, namely: The Northwest Power Pool Area, which is winter peaking and heavily dependent on hydroelectric generation (64% of installed capacity); the Rocky Mountain Power Area, which can be either summer or winter peaking with a 25% hydroelectric and 60% coal-fired generating capacity mix; the Arizona-New Mexico Power Area, which is summer peaking with an 18% nuclear and 45% coal-fired generating capacity mix; and the California-Southern Nevada Power Area, which is summer peaking and heavily dependent on gas-fired generating units (47% of installed capacity).

Assessment of the 1996–2005 generation adequacy indicates that sufficient generating capacity margins exist in each of the three major customer demand areas: the Fairbanks area, the Anchorage Bowl, and the Kenai Peninsula.

Reliability risks for system-wide blackouts due to single contingency outages will decrease with construction of a second line connecting the Kenai Peninsula and the Anchorage Bowl and with the second transmission line between the Healy coal-fired generating plant and the major demand in the Fairbanks area.

ASCC Systems

This assessment addresses only the interconnected electric systems of the Alaska Systems Coordinating Council (ASCC) serving the Fairbanks area, Anchorage Bowl, and the Kenai Peninsula. These systems are commonly known as the Alaska Railbelt electric utility systems. The Alaska Railbelt electric utilities began coordinated operations in 1984 by interconnecting the Fairbanks area with the Anchorage Bowl. (The Anchorage Bowl became interconnected with the Kenai Peninsula in the 1960s.)

The remaining ASCC electric utilities around the state also have an ongoing interest in reliability. All ASCC utilities (both interconnected and isolated systems) adopted the ASCC Planning Criteria for the Reliability of Interconnected Electric Utilities and the ASCC Operating Guides, thereby ensuring that all future interconnections will be addressed under the same criteria.

Demand and Energy

Peak demand for the Alaska Railbelt electric utilities occurs in the winter. The 1995/96

winter peak demand was 678 MW. The projected peak for the 1996/97 winter is 710 MW. The winter peak demand forecast indicates an average annual growth rate of 1.2% for the 1996–2005 period.

Annual electrical energy requirements to be supplied by the Alaska Railbelt electric utilities are expected to increase about 1.7% over the forecast period.

Resource Assessment

Assessment of the generation adequacy indicates that sufficient capacity margins exist in the three major customer demand areas. The capacity mix is currently 67% natural gas, 16% oil, 12% hydro, and 4% coal.

The Intertie Operating Agreement sets forth the criterion for generation reserve margin, currently 30%, used by the interconnected Railbelt utilities.

Transmission Assessment

A major reliability issue in the Alaska Railbelt area is transmission adequacy. In 1993, the Alaska legislature passed bills partially funding Regional

transmission interties. Reliability risks for system-wide blackouts due to single contingency outages will decrease with the construction of a second line connecting the Kenai Peninsula and the Anchorage Bowl and with the second transmission line between the Healy coal-fired generating plant and the major demand in the Fairbanks area.

Funds also were given as an interest-free loan to construct a transmission Intertie connecting Glennallen and Valdez to the interconnected system for the first time.

A second line between the Kenai Peninsula and the Anchorage Bowl will improve reliability by preventing the loss of electric service to customers if the existing 115 kV interconnection line trips. The second line also will help to reliably distribute the 108 MW Bradley Lake hydroelectric project. The link between the Anchorage Bowl and the Fairbanks area will benefit from increased reliability when the second 138 kV line from Fairbanks to Healy is constructed. A new line connecting the Copper Valley Electric service area will further efforts to satisfy traditional reliability criteria by interconnecting Glennallen and Valdez to the Railbelt grid.

Operations Assessment

To enhance reliability, each Alaska Railbelt electric utility brings into service additional generating units in anticipation of adverse weather. These generation services are geographi-

cally located so as not to be restricted by transmission contingencies.

In addition, electric load shedding schedules have been approved and implemented. In June 1995, NERC's Monitoring Working Group assembled a team to review the four control areas that comprise the Alaska Railbelt systems. Reports from this review provided the participating utilities with recommendations designed to enhance reliability.

Reliability Issues

Benefits from the new interties carry with them increased responsibility. Coordinated operations that follow ASCC and NERC reliability standards and guides become more critical in scheduling decisions as well as long-term capacity requirements. This year, the NERC Reliability Criteria Subcommittee reviewed the ASCC Planning Criteria for conformance to the NERC Planning Principles and Guides. This conformance review helped to ensure that new additions to the interconnected systems are measured against NERC-conforming ASCC Planning Criteria.

The Alaska Systems Coordinating Council (ASCC) is comprised of 17 utilities, two state agencies, and a federal agency. Nine ASCC members are interconnected in the Railbelt region of the state. These nine members account for 75% of the utility net generation in Alaska.

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SPP
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WSCC
Western Systems Coordinating Council

AFFILIATE

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Alaska Systems Coordinating Council