Reliability Assessment

2001–2010

The Reliability of

Bulk Electric Systems

in North America

North American Electric Reliability Council

October 16, 2001

CONTENTS

About This Report

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

This *Reliability Assessment 2001–2010* report presents:

- an assessment of electric generation and transmission reliability through 2010,
- a discussion of key issues affecting reliability of future electric supply, and
- Regional assessments of electric supply reliability, including issues of specific Regional concern.

In preparing this report, RAS:

- reviewed summaries of Regional self assessments, including forecasts of peak demand, energy requirements, and planned resources,
- appraised Regional plans for new electric generation resources and transmission facilities, and
- assessed the potential effects of changes in technology, market forces, legislation, regulations, and governmental policies on the reliability of future electric supply.

The data in this report reflects conditions that were projected as of June 20, 2001. Detailed background data are available in NERC's *Electricity Supply & Demand* (ES&D) database, 2001 edition (http://www.nerc.com/~esd/).

The majority of new generation additions over the next few years is expected to be constructed by the rapidly growing merchant generation industry. NERC is collaborating with the Electric Power Supply Association (EPSA) to capture as much information regarding merchant plant additions as possible. In addition, NERC has contracted with Energy Ventures Analysis, Inc. (www.evainc.com) to monitor proposed new power plant projects and track their status. In some cases, data available from EPSA and EVA are used in this report to supplement data submitted by the Regions.

Assessment Time Frame

RAS views this ten-year assessment in two time frames: the near term, consisting of the first five years and the long term, which is the balance of the ten-year period. Although the near term represents a fairly accurate forecast of future conditions, the longer-term assessment must be considered more an indication of future trends than an absolute. Assessing reliability beyond the near term is extremely difficult because of the level of uncertainty and quality of information provided for modeling and analysis. The uncertainty in the data is due primarily to the reluctance of some industry participants to establish long-term firm energy commitments in light of an uncertain future or to reveal future plans for competitive reasons. Similarly, transmission plans projected more than five years in the future are tentative because justification studies usually have not been completed and regulatory approvals have not been received.

About NERC

On November 9, 1965, a blackout left 30 million people across the Northeastern United States and Ontario, Canada in the dark. In an effort to prevent this type of blackout from ever happening again, electric utilities formed the North American Electric Reliability Council (NERC) in 1968 to promote the reliability of the electricity supply for North America. This mission is accomplished by working with all segments of the electric industry as well as customers. NERC reviews the past for lessons learned, monitors the present for compliance with policies, and standards, and assesses the future reliability of the bulk electric systems.

FOREWORD

NERC's members are ten Regional Councils encompassing virtually all of the electric systems in the continental United States, Canada, and the northern portion of Baja California Norte, Mexico. The members of these Regional Councils come from all segments of the electric industry — investor-owned, federal, rural electric cooperatives, state/municipal and provincial utilities, independent power producers, and power marketers.

Since 1968, NERC has relied entirely on voluntary efforts and "peer pressure" to ensure compliance with its standards. This voluntary arrangement is simply no longer adequate. The users and operators of the system who used to cooperate voluntarily on reliability matters are now competitors without the same incentives to cooperate with each other or comply with voluntary reliability rules. Little or no effective recourse exists today under the current voluntary model to correct such behavior. No single bulk electric system reliability standard can be enforced effectively today by NERC or the Federal Energy Regulatory Commission (FERC).

To ensure the continued reliability of the interconnected bulk electric systems throughout North America in the face of these changes, reliability rules must be made mandatory and enforceable, and fairly applied to all participants in the electricity market. To meet this need, NERC and a broad coalition of industry organizations have proposed the creation of a single, industry-based self-regulatory reliability organization (SRRO) to develop and enforce mandatory reliability rules with FERC oversight in the United States to ensure that the SRRO and its affiliated Regional reliability entities operate effectively and fairly. The proposal follows the model of the Securities and Exchange Commission in its oversight of the securities industry self-regulatory organizations (the stock exchanges and the National Association of Securities Dealers). As the industry evolves toward full competition, the SRRO will have to examine traditional reliability planning practices and policies to ensure that they are still applicable and that they continue to result in reliable electric systems.

Resource Adequacy

Near-term (2001–2005) generation adequacy is deemed satisfactory throughout most of North America, provided new generating facilities are constructed as anticipated. Projected near-term, NERC-wide capacity margins continue to show increases over projections from previous years, peaking at more than 20% in 2004. Although electricity demand is expected to grow by about 63,800 MW in the near term, new resource additions totaling from about 138,000 to 245,000 MW are projected over the same period depending upon the number of merchant plants assumed to be in service. Even though North American aggregate capacity margins appear adequate, there are some areas that have a higher risk of experiencing outages due to local conditions.

Long-term (2006–2010) generation adequacy is more difficult to assess than the near term, but if current trends continue, long-term adequacy also will be satisfactory. Long-term adequacy is dependent upon the continued response of merchant power plant developers to market signals to construct new generating facilities (and their ability to obtain the necessary siting and environmental approvals) in areas experiencing declining capacity margins. The timing of new capacity additions is critical. Because new generating capacity additions are being driven by market signals and not the maintenance of a target resource adequacy criteria, capacity margins will likely fluctuate, similar to normal business cycles experienced in other industries.

A great deal of uncertainty surrounds future capacity additions, including the ability to obtain suitable interconnection and transmission access agreements, the ability to obtain necessary siting and environmental permits, the ability to obtain financial backing, and fuel prices and supply. In addition, political and regulatory actions could influence the amount of new generation built over the next ten years. FERC's institution of wholesale power price caps in the western United States and state mandated moratoriums on the construction of new generating facilities within their borders are recent examples.

Transmission Adequacy

In the near term, transmission congestion is expected to continue. Demand growth, new generation additions, and the increasing number of energy transactions continue to outstrip the proposed expansion of transmission systems. Only 7,276 miles of new transmission operated at 230 kV and above are proposed to be added in the near term. A reliable level of transmission system operation will be highly dependent upon increased coordination with surrounding systems and proper transmission system operator actions. Absent new transmission facilities, electricity transactions will continue to be curtailed.

The reliability of the interconnected transmission systems in the long term will be highly dependent upon the location of new generating resources. Unless mechanisms are developed to encourage investment in new transmission facilities and siting issues are addressed, few new transmission facilities and reinforcements will be constructed. This lack of additional transmission facilities and reinforcements will require either that new technologies be developed to alleviate transmission congestion or that generating facilities be located and dispatched in a manner to minimize the use of constrained transmission corridors. The close coordination of generation and transmission planning of the past that resulted in the highly reliable electric systems of North America must now be accomplished through different means and coordinated among many different market participants. Market signals and regulatory decisions will dictate the location and timing of generating capacity additions, and also will influence the planning of transmission additions.

Fuel Supply Adequacy

Coal remains the predominant fuel used in the production of electricity, but nearly all recently built power plants and almost all of those proposed for the future use natural gas as their primary fuel. Natural gas-fired facilities are projected to generate about 20% of North America's electricity by 2009, compared to just 8% in 1991. With the continuing growth in natural gas use by the electric industry, the adequacy and security of the natural gas supply and its delivery will become more critical to the reliability of the electric systems. In the near term, gas supplies are expected to be adequate.

EXECUTIVE SUMMARY

The concern with the adequacy of supply of natural gas in the long term lies in the physical location of the gas. The bulk of current drilling activity is confined to known or proven reserves, which produce quick returns that are easy to capitalize at currently high gas prices. However, these are typically shallow wells with limited long-term capacity that can be depleted quickly via current extraction technology. As the demand for natural gas increases, gas reserves available in desirable and accessible locations will start to deplete. Gas exists in other areas to replace these reserves, but it may be more expensive to extract or may require the development of new technology to process it.

The gas pipeline infrastructure also must maintain its viability and integrity as the electric industry becomes increasingly dependent on a secure delivery of natural gas. The pipeline systems in North America do not employ redundancy, increasing the impacts of single pipeline failures on reliable gas deliveries. The pipeline system also is aging in some areas and requires rigorous maintenance. Finally, it is increasingly difficult to site new pipelines. If the gas pipeline infrastructure cannot continue to be expanded, congestion akin to that experienced on the electric transmission system may ensue.

Issues

A number of issues are discussed in the report to alert readers to their potential impacts upon reliability. These issues include:

RTO development — FERC has ordered mediation for two United States Regional Transmission Organizations (RTOs) in the eastern United States and has suggested that a total of five (or even six) RTOs would be desirable to facilitate the development of a competitive electricity market. RTOs will also be responsible for the reliability of the interconnected power system, which will be a significant challenge, particularly during the transition period from more than 140 existing control areas to the RTO structure envisioned by FERC. Both commercial and reliability seams issues between the RTOs must be addressed. Furthermore, it is still not clear how RTOs will identify, plan, construct, and pay for necessary transmission system expansion and reinforcements.

Industry restructuring — United States restructuring efforts continue with the goal of achieving lower costs to customers while maintaining the level of reliability currently enjoyed across North America. Unfortunately, the reliability impacts of a restructured market may not be known until the market operates. The move to market driven, decentralized generation planning can have short-term benefits, but can also lead to over reliance on single fuel types or generating capacity types in the long run. The success of fully functional electricity markets will depend upon deregulation of not just the supply side, but also the demand side market.

Environmental regulations — The potential reliability impacts associated with environmental policy and regulatory actions depend largely on the details of their implementation, which have not been fully developed. Important factors in assessing potential reliability impacts include the stringency of the requirements, the length of compliance schedules, scope of geographic applicability, coincidence with other regulatory requirements, the amount of generation needing modification and retrofit outage duration, among others.

Definition of Reliability

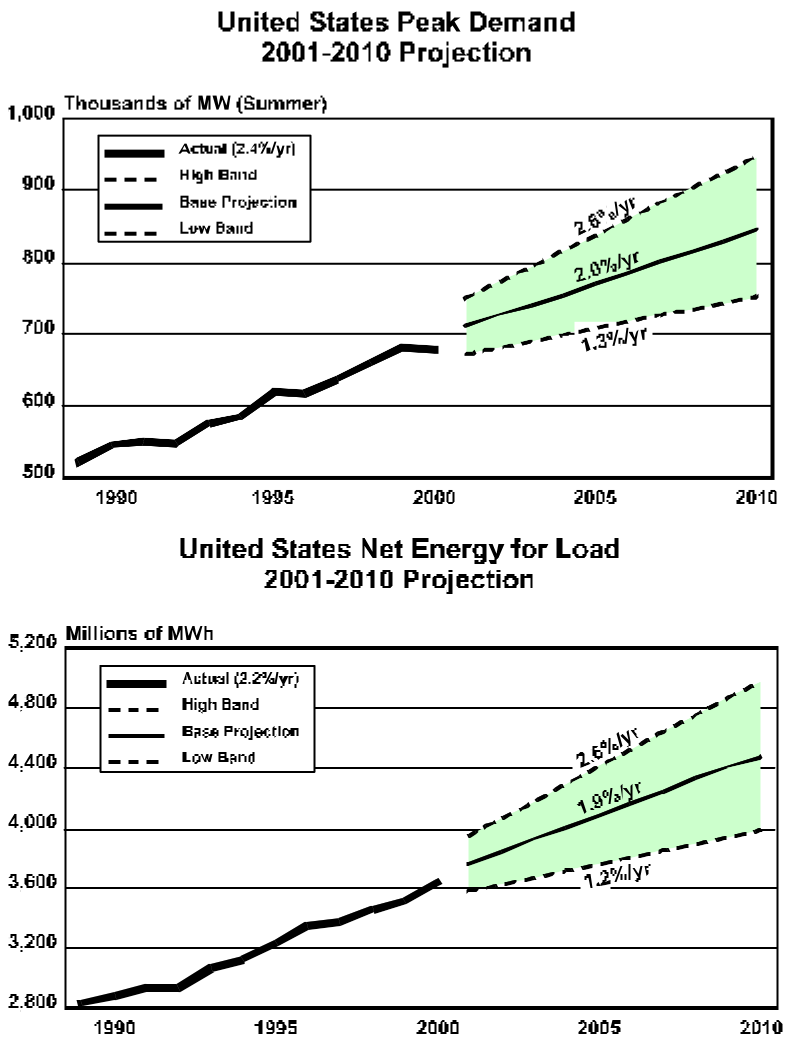
NERC defines the reliability of the interconnected bulk electric systems in terms of two basic, functional aspects:

1. Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
2. Security — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Demands and Resources

The average annual United States peak demand growth over the next ten years is projected to be 2%, up slightly from the 1.9% forecast last year. The demand projections in Figures 1 and 2 represent an aggregate of weather-normalized Regional member forecasts assembled by NERC's Load Forecasting Working Group (LFWG). LFWG develops bandwidths around the aggregate United States and Canadian demand projections, to account for uncertainties inherent in demand forecasting. NERC does not prepare its own independent demand forecast because local entities are best suited to make appropriate assumptions concerning diversity, weather, and economic conditions, which are key drivers of the demand forecast.

Figure 1



Forecast Bandwidths

Forecasts cannot precisely predict the future. Instead, many forecasts attach probabilities to the range of possible outcomes. Each base demand projection, for example, represents the midpoint of possible future outcomes. The future year's actual demand has a 50% chance of being higher and a 50% chance of being lower than the forecast value. Capacity resources historically have been planned for the 50% demand projections.

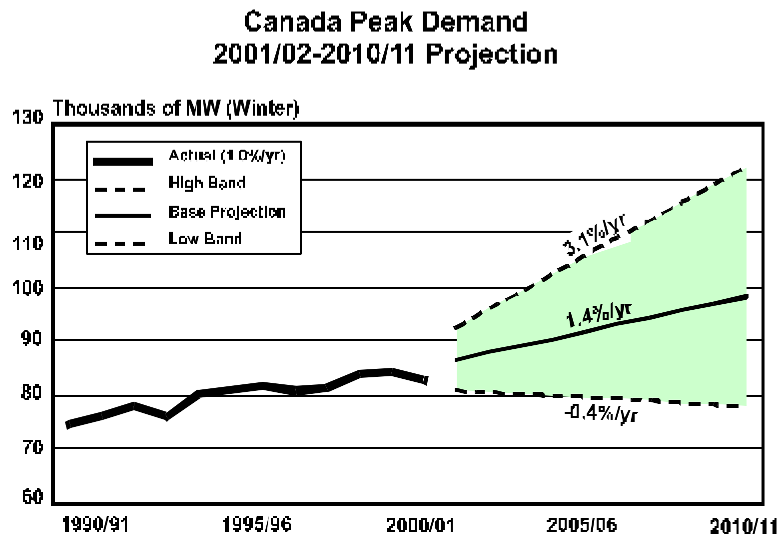
For planning purposes, it is useful to have an estimate not only of the midpoint of possible future outcomes, but also of the distribution of probabilities on both sides of that midpoint. Accordingly, NERC's Load Forecasting Working Group develops upper and lower 80% confidence bands around the NERC-aggregated demand projections. Therefore, there is an 80% chance of future demand occurring within these bands, a 10% chance of future demand occurring below the lower band, and an equal 10% chance of future demand occurring above the upper band.

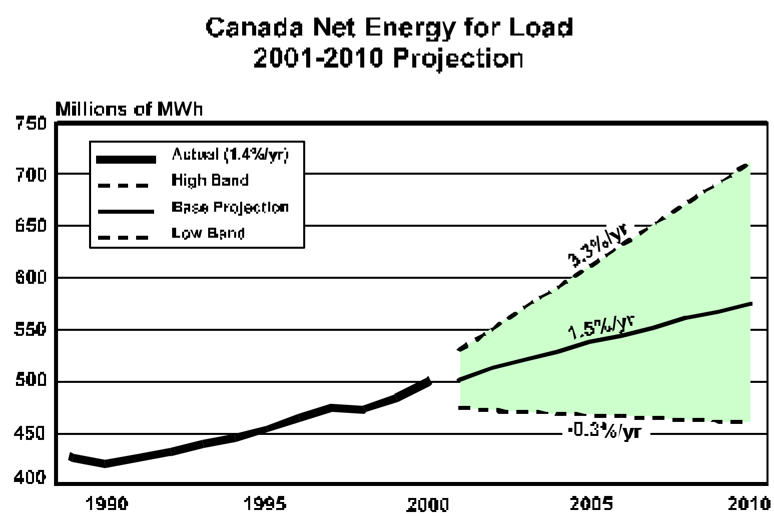
ASSESSMENT OF RELIABILITY

In recent years, an apparent divergence occurred between actual demand growth and future aggregate projections for the United States. The LFWG conducted an examination of this apparent divergence and determined it was primarily due to the assumptions made regarding the expected future economic growth in the country. A report is available on the NERC web site at http://www.nerc.com/~filez/lfwg.html. Although the average historical demand growth rate for the last ten years is 2.4%, this growth rate is not expected to continue into the future. The last ten years have experienced unprecedented economic growth in the United States; this economic growth has slowed and is reflected in the current projections. Last year's historical ten-year growth rate was 2.7% compared to the 2.4% for this year, reflective of the economic slowdown and its impact. It is important to note that the demand growth rate projections are a ten-year average and that individual years may experience greater or lesser rates.

The projected ten-year peak demand growth rate in Canada is expected to be 1.4%, up slightly from the 1.2% growth rate projected last year. As with the United States projections, forecast uncertainty is shown by the bandwidths around the base forecasts in Figure 2.

Figure 2





Resource Adequacy Assessment

Capacity adequacy in North America over the next ten years will continue to be dependent upon the timely construction of new generating facilities by merchant power plant developers. Merchant power plant developers announced plans for more than 290,000 MW[1] of new capacity during the course of the ten-year period. Although some of this merchant capacity was included in the capacity projections reported to NERC by its Regions, much is not, due to the uncertainty surrounding some of the projects.

Nearly all proposed new generating facilities are merchant projects. In the past, vertically integrated utilities planned and constructed new generating units to meet fixed resource adequacy criteria targets, such as a certain percent reserve margin or a specified loss-of-load probability, often developed in collaboration with state regulatory agencies. Today, as restructuring advances within the industry, generation planning is conducted by developers who examine areas of the continent that offer the greatest financial incentives to investors. These incentives may include declining capacity margins, access to fuel supplies, access to the transmission system, and ease of permitting. As industry restructuring progresses, capacity margins may exhibit the characteristics of normal business cycles found in other industries, i.e., periods of advances and declines.

Figure 3

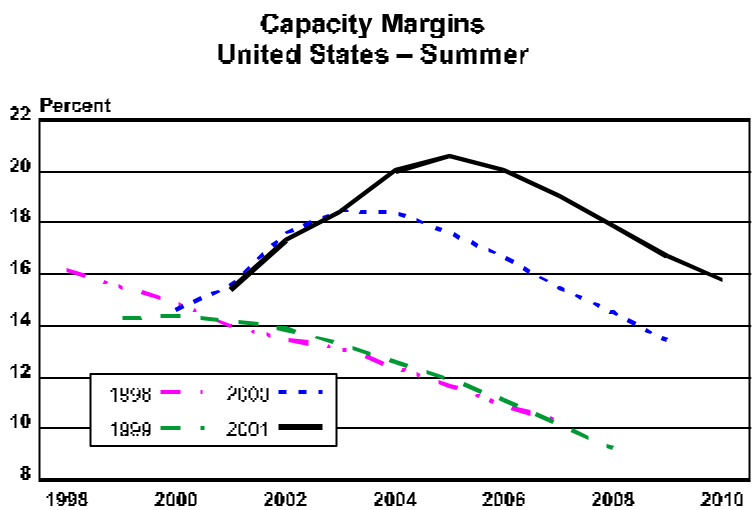
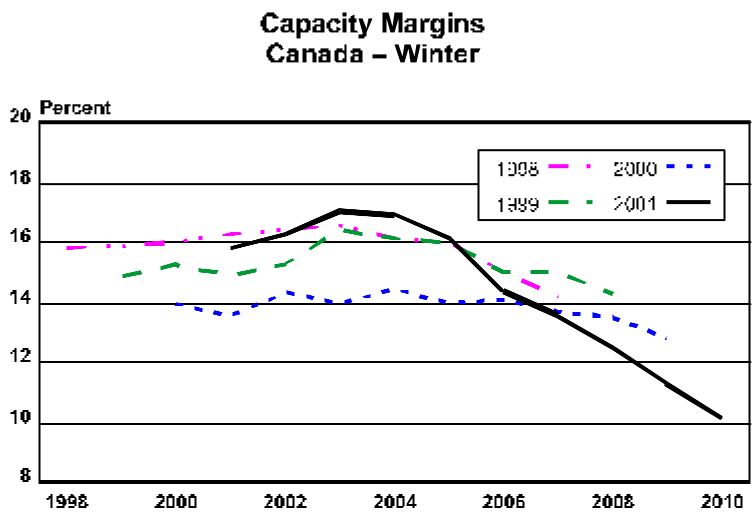


Figure 3 compares the projected ten-year United States capacity margins for the last four years as reported to NERC by the Regions. After several years of decline, 2000 was the first year in which the United States capacity margins increased, rising sharply over the first five years of the report horizon as numerous new merchant power plants were announced in response to market signals. This trend continues in the current ten-year projections, with capacity margins reaching over 20% in 2004. The margin erodes during the latter half of the ten-year period to about 15%, as demand continues to grow while the number of proposed new generating units decline. Shifting incentives coupled with short lead times to construct new generating facilities, make the increases in near-term projected capacity margins more understandable. The fact that fewer capacity additions are projected beyond 2005 does not mean that additions will not occur, but rather that these decisions have not yet been made or are being held confidential for competitive reasons.

1 - As reported by EPSA as of June 20, 2001. New merchant capacity announcements may have been made since that time.

Projected ten-year capacity margins in Canada are shown for the winter months in Figure 4 as Canada reaches its aggregated peak demand in the winter. Projected capacity margins continue to remain in the 16–17% range in the near term and drop off in the long term, as announced new power plants decline, similar to what is occurring in the United States.

Figure 4



The market has begun to respond in areas of capacity deficiencies, and merchant generation will continue to play a major role in the future power supply of North America. The data reported by the Regions used to create Figures 3 and 4 and Table 1 represents the Regions' best estimates of projected new resource additions, balancing the amount of announced new merchant plants with the likelihood of each project actually being built and meeting its targeted in-service date. Additional information on announced merchant generation capacity additions, compiled by the Electric Power Supply Association (EPSA) and Energy Ventures Analysis, Inc. (EVA), was used in this report to gauge the level of reliance on new merchant capacity. EPSA is tracking plans for more than 245,000 MW[1] of merchant generation additions that have been announced in the United States by the end of 2004. Although not all of that capacity is assured of being constructed, its impact on future reliability will be critical.

Figure 5 illustrates the possible range of projected capacity margins for the United States over the next ten years. Because it is difficult to accurately predict the exact number and in-service dates of future capacity additions merchant developers will actually construct, this report provides a range of potential values. The announcement of a new merchant generating facility does not necessarily guarantee its construction for a variety of reasons, including future market prices, the ability to obtain suitable interconnection and transmission access agreements, and the ability to obtain financial backing and other business-related factors. In some cases, a single developer may announce several projects, even though only one will be built. Such announcements are made because developers cannot be assured of obtaining all the necessary permits to build a power plant at one location, forcing them to alternate locations as a contingency plan. In other cases, economic or political conditions may change, making a project unprofitable and leading to its cancellation. For example, recent volatility in natural gas prices may cause developers to review previously announced plans to construct new gas-fired generating units. Similarly, the institution of price caps for wholesale electricity sales also may lead to project cancellations. Finally, some states have issued moratoriums on new power plant construction because the capacity of the proposed facilities exceeds

1 - As reported by EPSA as of June 20, 2001. New merchant capacity announcements may have been made since that time.

the projected future demand for electricity in the state or they are concerned about the environmental consequences of hosting generating facilities whose output could be sold out of state.

Using detailed project information from EVA to supplement information supplied by the Regions, Figure 5 shows a range of capacity margins for the next ten years. EVA maintains a database of all proposed new power plants in the United States and tracks various milestones associated with the completion of the projects, including applications for environmental permits, siting, acquisition of equipment, financing, and contractual arrangements to sell the output of the facilities. Using this key information, RAS was able to screen announced new merchant plants to establish those most likely to be built. Four separate capacity margin projections are shown in Figure 5: the lower bound is the projected margin including only capacity resources currently in operation or under construction, the upper bound is the projected margin if all announced new merchant power plants are constructed. Neither of these two cases is deemed likely; they are included for perspective. The line labeled "Reported by Regions" reflects the capacity margins as reported by NERC's Regions. The line labeled "Existing + EVA Supplement" reflects the projected capacity margins after supplementing Regional data with data received from EVA. RAS believes that this line is the most likely scenario going forward; this projection does not differ vastly from the Regions' projections.

The capacity margin projections include the effects of currently planned generating unit retirements. They do not, however, include unit retirements that may occur as newer, more efficient plants come online and older assets are deemed uneconomic. These retirements are difficult to project and are yet another uncertainty associated with developing long-term resource adequacy projections. Although the overall capacity is expected to be adequate to serve projected demands, pockets of North America may experience deficiencies even as new generating resources are added elsewhere or if transmission limitations limit the delivery of energy to demand centers.

Figure 5

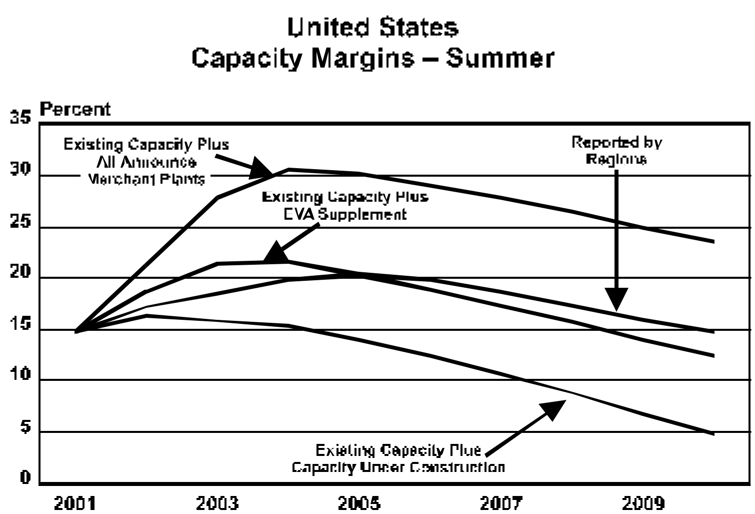
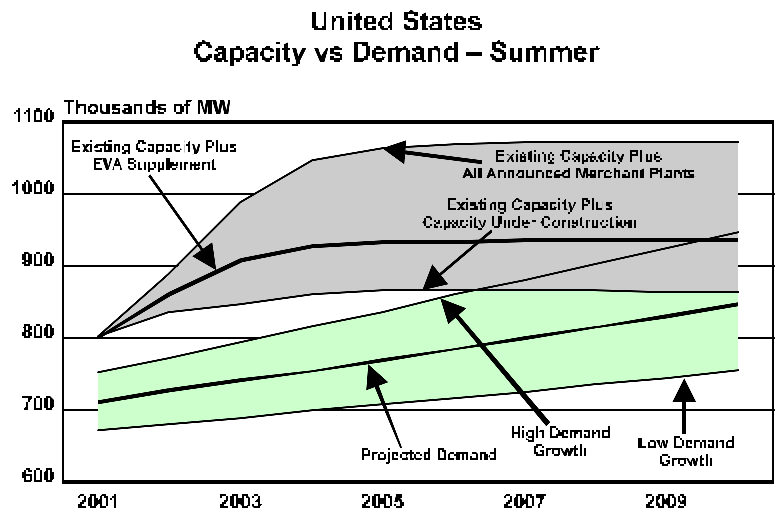


Figure 6 overlays the projected U.S. capacity resources for the next ten years on the projected demand bandwidths. Three resource lines are shown: the first is projected capacity resources without the inclusion of any generators that are not currently operational or under construction ("Existing + Under Construction Only"); the second is RAS' best estimate of future capacity resources ("Existing + EVA Supplement"); and the last line indicates the future resource situation if all announced merchant generation is constructed and brought on line ("Existing + All Announced Merchant Plants"). Though it is highly unlikely the highest or lowest capacity resource lines will materialize, they are included to provide perspective. Figure 6 shows that absent any new resource additions, projected electricity supplies should exceed base-line demand projections throughout the ten-year period.

Figure 6



Canada's capacity margins for the next ten years are shown in Figures 7 and 8. Figure 7 illustrates a range of capacity margins, with the lower line showing projected capacity margins incorporating only existing power plants and those currently under construction. The upper line includes all proposed new capacity reported by the NERC Regions. Information regarding proposed new Canadian capacity additions beyond that reported by the Regions is not currently available; hence only two capacity margin lines are shown on Figures 7 and 8, as opposed to the multiple projections for the United States. Figure 8 superimposes the projected capacity resources for the next ten years upon the projected demand bandwidths for the same time period. Absent any new capacity additions beyond those already under construction, Figure 8 indicates that expected Canadian demand for electricity will not exceed projected resources during the ten-year period.

Figure 7

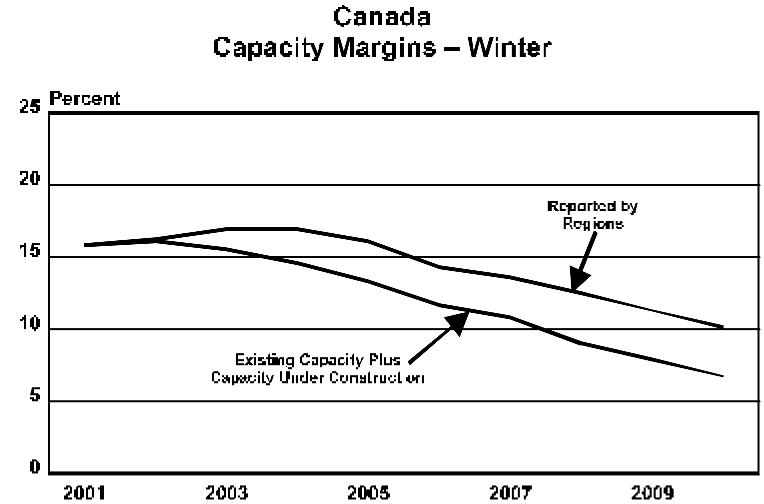


Figure 8

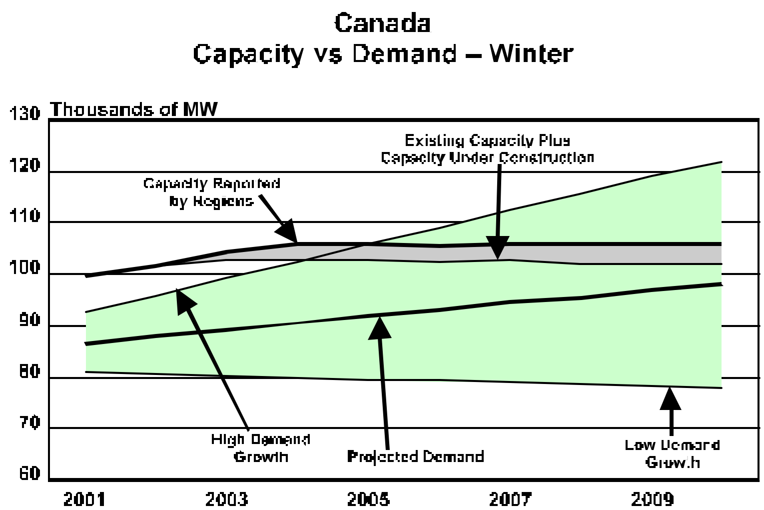


Table 1 contains projected capacity margins for 2001 and 2005 (both summer and winter) by NERC Region. The information in the Table was taken directly from submittals made by the NERC Regions. The information in Table 1 is also reflected in Figures 3 and 4.

Table 2 contains supplemental information regarding NERC-wide merchant capacity additions and demand by year.

Table 1: Demand and Capacity as Reported by the NERC Regions

Region	Total Internal Demand (MW)	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Reserve Margins (% of Net Internal Demand)	Capacity Margins (% of Capacity Resources)
		Summer — 2001			
ECAR	102,161	98,651	115,379	17.0	14.5
FRCC	38,478	35,666	43,083	20.8	17.2
MAAC	52,977	51,358	60,679	18.1	15.4
MAIN	55,368	51,845	64,170	23.8	19.2
MAPP–U.S.	29,814	28,006	34,236	22.2	18.2
MAPP–Canada	5,450	5,291	7,888	49.1	32.9
NPCC–U.S.	54,351	54,270	63,376	16.8	14.4
NPCC–Canada	45,452	44,139	66,684	51.1	33.8
SERC	159,930	151,527	169,760	12.0	10.7
SPP	40,522	39,056	46,109	18.0	15.3
Eastern Interconnection	584,503	559,809	671,364	19.9	16.6
WSCC–U.S.	118,887	116,913	141,640	21.1	17.5
WSCC–Canada	14,592	14,067	22,477	59.8	37.4
WSCC–Mexico	1,707	1,707	2,152	26.1	20.7
Western Interconnection	135,186	132,687	166,269	25.3	20.2
ERCOT Interconnection	56,759	53,649	69,622	29.8	22.9
United States	709,247	680,941	801,990	17.8	15.1
Canada	65,494	63,497	97,049	52.8	34.6
Mexico	1,707	1,707	2,152	26.1	20.7
NERC	776,448	746,145	885,704	18.7	15.8
		Summer — 2005			
ECAR	109,905	106,213	117,950	11.1	10.0
FRCC	42,644	39,898	49,119	23.1	18.8
MAAC	56,412	54,793	83,450	52.3	34.3
MAIN	59,157	55,656	70,896	27.4	21.5
MAPP–U.S.	31,930	29,892	34,402	15.1	13.1
MAPP–Canada	5,673	5,486	8,400	53.1	34.7
NPCC–U.S.	57,796	57,694	73,945	28.2	22.0
NPCC–Canada	48,197	47,343	69,759	47.3	32.1
SERC	173,496	165,476	189,877	14.7	12.9
SPP	43,932	42,279	47,684	12.8	11.3
Eastern Interconnection	629,142	604,730	745,482	23.2	18.9
WSCC–U.S.	129,199	127,895	187,209	46.4	31.7
WSCC–Canada	16,126	15,601	26,391	69.2	40.9
WSCC–Mexico	2,138	2,138	2,806	31.2	23.8
Western Interconnection	147,463	145,634	216,406	48.6	32.7
ERCOT Interconnection	63,480	61,827	83,242	34.6	25.7
United States	767,951	741,623	934,090	26.0	20.6
Canada	69,996	68,430	104,550	52.8	34.5
Mexico	2,138	2,138	2,806	31.2	23.8
NERC	840,085	812,191	1,024,101	26.1	20.7

Table 1: Demand and Capacity as Reported by the NERC Regions (continued)

Region	Total Internal Demand (MW)	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Reserve Margins (% of Net Internal Demand)	Capacity Margins (% of Capacity Resources)
		Winter — 2001/02			
ECAR	90,041	87,190	119,870	37.5	27.3
FRCC	42,208	38,199	45,665	19.8	16.5
MAAC	43,809	43,110	64,854	50.4	33.5
MAIN	43,663	41,250	63,075	52.9	34.6
MAPP–U.S.	24,661	23,748	32,777	38.0	27.5
MAPP–Canada	6,580	6,421	8,133	26.7	21.1
NPCC–U.S.	45,775	45,650	68,173	49.3	33.0
NPCC–Canada	61,954	59,972	69,371	15.7	13.5
SERC	139,459	131,779	169,850	28.9	22.4
SPP	29,804	28,761	45,501	58.2	36.8
Eastern Interconnection	527,954	506,080	687,269	35.8	26.4
WSCC–U.S.	102,237	101,270	144,185	42.4	29.8
WSCC–Canada	18,093	17,568	22,243	26.6	21.0
WSCC–Mexico	1,278	1,278	2,160	69.0	40.8
Western Interconnection	121,608	120,116	168,588	40.4	28.8
ERCOT Interconnection	44,394	41,606	72,598	74.5	42.7
United States	606,051	582,563	831,940	42.8	30.0
Canada	86,627	83,961	99,747	18.8	15.8
Mexico	1,278	1,278	2,160	69.0	40.8
NERC	693,956	667,802	915,157	37.0	27.0
		Winter — 2005/06			
ECAR	95,601	92,872	123,110	32.6	24.6
FRCC	46,454	42,425	53,024	25.0	20.0
MAAC	46,368	45,669	88,433	93.6	48.4
MAIN	45,302	43,533	70,136	61.1	37.9
MAPP–U.S.	26,288	25,223	33,628	33.3	25.0
MAPP–Canada	6,888	6,701	8,672	29.4	22.7
NPCC–U.S.	48,646	48,498	77,539	59.9	37.5
NPCC–Canada	64,906	62,944	71,569	13.7	12.1
SERC	151,029	143,078	192,633	34.6	25.7
SPP	32,150	30,941	47,671	54.1	35.1
Eastern Interconnection	563,632	541,884	766,415	41.4	29.3
WSCC–U.S.	110,458	109,670	192,723	75.7	43.1
WSCC–Canada	19,940	19,415	25,926	33.5	25.1
WSCC–Mexico	1,653	1,653	2,814	70.2	41.3
Western Interconnection	132,051	130,738	221,463	69.4	41.0
ERCOT Interconnection	50,375	49,221	83,761	70.2	41.2
United States	652,671	631,130	966,691	53.2	34.7
Canada	91,734	89,060	106,167	19.2	16.1
Mexico	1,653	1,653	2,814	70.2	41.3
NERC	746,058	721,843	1,056,639	46.3	31.7

Table 2 — NERC — Summer

	2001	2002	2003	2004	2005
Internal Demand	776,448	793,033	808,175	823,557	840,085
Interruptible Demand & DCLM	30,303	28,007	27,651	27,729	27,894
Net Internal Demand	746,145	765,026	780,524	795,828	812,191
Generating Capacity Reported by Regions	885,767	930,198	963,007	999,257	1,024,194
Margin (MW)	139,622	165,172	182,483	203,429	212,003
Capacity Margin (%)	15.8	17.8	18.9	20.4	20.7
Planned Capacity Additions Not Under Construction	855	9,951	27,763	51,066	71,793
Net Capacity Resources Less Capacity Not Under Construction as Reported by Regions	884,913	920,247	935,244	948,191	952,401
Resulting Margin (MW)	138,768	155,221	154,720	152,363	140,210
Resulting Capacity Margin (%)	15.7	16.9	16.5	16.1	14.7
New Merchant Capacity (EVA Supplement)	–*	59,614	47,217	20,077	4,771
New Merchant Capacity (EVA Supplement) Plus Existing Resources	885,767	945,381	992,598	1,012,675	1,017,446
Resulting Margin (MW)	139,622	180,355	212,074	216,847	205,255
Resulting Capacity Margin (%)	15.8	19.1	21.4	21.4	20.2
All Announced New Merchant Capacity	–*	86,993	100,238	59,421	16,425
All Announced New Merchant Capacity Plus Existing Resources	885,767	972,760	1,072,998	1,132,419	1,148,844
Resulting Margin (MW)	139,622	207,734	292,474	336,591	336,653
Resulting Capacity Margin (%)	15.8	21.4	27.3	29.7	29.3

*** 2001 merchant capacity assumed to be on line and included in Regional reporting for 2001 existing resources.**

Table 2 — NERC — Summer (continued)

	2006	2007	2008	2009	2010
Internal Demand	855,873	871,823	888,200	905,053	921,438
Interruptible Demand & DCLM	27,961	28,209	28,276	28,296	28,044
Net Internal Demand	827,912	843,614	859,924	876,757	893,394
Generating Capacity Reported by Regions	1,036,151	1,041,562	1,045,335	1,048,305	1,052,611
Margin (MW)	208,239	197,948	185,411	171,548	159,217
Capacity Margin (%)	20.1	19.0	17.7	16.4	15.1
Planned Capacity Additions Not Under Construction	83,027	89,020	93,895	99,300	104,017
Net Capacity Resources Less Capacity Not Under Construction as Reported by Regions	953,124	952,542	951,440	949,005	948,594
Resulting Margin (MW)	125,212	108,928	91,516	72,248	55,200
Resulting Capacity Margin (%)	13.1	11.4	9.6	7.6	5.8
New Merchant Capacity (EVA Supplement)	941	1,035	45	230	0
New Merchant Capacity (EVA Supplement) Plus Existing Resources	1,018,387	1,019,422	1,019,467	1,019,697	1,019,697
Resulting Margin (MW)	190,475	175,808	159,543	142,940	126,303
Resulting Capacity Margin (%)	18.7	17.2	15.6	14.0	12.4
All Announced New Merchant Capacity	3,765	2,560	180	918	0
All Announced New Merchant Capacity Plus Existing Resources	1,152,609	1,155,169	1,155,349	1,156,267	1,156,267
Resulting Margin (MW)	324,697	311,555	295,425	279,510	262,873
Resulting Capacity Margin (%)	28.2	27.0	25.6	24.2	22.7

Regional Highlights

RAS has highlighted the following Regions in this report that are of particular interest. The Regional self-assessments that appear later in this report contain further details about these areas.

NPCC — New York City and Long Island

Current projections indicate that New York City and Long Island will not meet reliability criteria requirements beyond 2001 unless conditions improve. NPCC requires that its members meet a standard loss-of-load-expectation of one day in ten years, which translates to about an 18% reserve margin for New York. Of particular concern are the New York City and Long Island areas, which are transmission and voltage constrained. In addition to maintaining an 18% planning reserve, the New York Independent System Operator (NYISO) also requires that New York City meet 80% of its demand with internal generating resources and that Long Island meet 98% of its demand internally due to local security concerns. Projections are that these areas cannot meet these requirements beyond 2001. There are some 10,000 MW of new generation proposed for these areas and the future adequacy of these areas will depend upon the timely completion of these proposed projects. None of these projects were included in the future capacity projections for New York, because they have not yet been sited.

WSCC — California

The future outlook for California's electricity supply and demand should be viewed in two stages, between today and the summer of 2003, and between 2003 and 2010. In the near term, projected shortages of generating capacity are anticipated if demand grows at the recent rate of about 2% per year. This summer, consumer conservation, both voluntary and through various state programs, was an effective tool in helping to prevent rotating outages on peak demand days. Additionally, about 1,000 MW of new generation has come on line since last summer, and another 1,000 MW should be on line by summer 2002.

The outlook between 2003 and 2010 is fairly optimistic as the state continues to encourage generators to site and build power plants in California. The state also has entered into long-term energy contracts with power suppliers, some of which extend into 2010. Substantial upgrades are expected to be made to the transmission system during this period, including another 500 kV circuit in Path 15, another 500 kV tie into Southern California to improve reliability in the San Diego area, and a major upgrade on 230 kV circuits into Baja Mexico (where an aggressive generation building program exists). The California Power Authority appears to be poised to issue $5 billion in bonds for the construction of power plants in California. This construction is in addition to the long-term contracts that have been negotiated by the state and any other commitments to site and build new generation in California.

MAPP — U.S.

Current projections indicate that the United States portion of MAPP will not meet the MAPP target level of reliability in some future years (15% reserve margin). New generation beyond what is currently planned must be added to meet the MAPP reserve capacity obligation requirements in the future.

SERC

A large amount of new merchant generation was announced in SERC. A large portion of this generation, however, was not included in the data reported by the Region because it has not been contracted for and SERC cannot determine if the capacity will be dedicated to serve demand within its borders. The sheer amount of new generation in the Region would seem to indicate that the capacity margins reported in Table 1 for the Region are pessimistic. Easy access to ample natural gas supplies in the Entergy subregion of SERC has made it a hot bed of new merchant power plant activity. Projects exceeding the current demand of the subregion have been announced for construction over the next ten years. If all of these projects are built, the output of some of that capacity may be stranded, as it will not be needed to serve local demand, and insufficient transmission capability currently exists to transfer the energy to other demand centers.

ERCOT

ERCOT has successfully added both new generation and transmission facilities. Resource adequacy was a concern in this Region just a few years ago; since then, significant amounts of new generating capacity have been added in a relatively short lead-time (almost 13,000 MW have been added in 2000 and 2001 alone). The streamlined ERCOT interconnection process for new generators has expedited the connection of new generating facilities to the transmission system. In addition, ERCOT is one of the few areas of the continent to have built major new transmission reinforcements to reduce transmission congestion across its Region. As a result, ERCOT has not, and is not expected to experience electricity shortages.

Transmission Adequacy and Security Assessment

The North American transmission systems are expected to perform reliably in the near term. Procedures and processes to mitigate potential reliability impacts appear to be working effectively for now. However, portions of the transmission systems are reaching their limits as customer demand increases and the systems are subjected to new loading patterns resulting from increased power transfers. Although some transmission constraints are recurring and well known, others are not. Many electricity transfers are influenced by weather diversity across the continent that frees up resources in one area to serve demand in another. Because weather patterns are unpredictable in the long term, transmission constraints and congestion have the potential to shift from season to season and year to year. In cases where redispatch options have been exhausted or are ineffective, the only way to remove the constraints is to increase the capability of the transmission system or build new generation close to the demand centers, removing the need for the power transfer in the first place.

The transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed or for which there is minimal operating experience. New flow patterns result in an increasing number of facilities being identified as limits to transfers, and transmission loading relief (TLR) procedures have been required in areas not previously subject to overloads to maintain the transmission facilities within operating limits. NERC TLR is called by security coordinators as a last resort to curtail transactions that cause transmission facility overloads or violations of operational security limits. Transmission facility overloads or operation at levels near security limits do not necessarily translate into an unreliable or unsecure transmission system; these conditions may instead be an indication that the transmission system is fully utilized and will not support any further economic transfers of energy. Several steps or classifications of NERC TLR exist, ranging from Level 0 to 6.[2] Curtailments of transactions do not occur until Level 3 (non-firm) and Level 5 (firm).

Figure 9 depicts the number of TLR events for the past five years as reported to NERC. The number of TLRs has steadily increased as power transfers increased and the transmission system has become more fully subscribed. The year 2000 saw a significant increase in the number of TLRs as heavy north-to-south power transfers occurred in the central United States, spurred on by extended temperature diversity (cool in the north and hot in the south), which freed up resources for export. The number of TLR events experienced so far in 2001 is below the TLR levels of last summer, but 2000 is a reminder that flows on the transmission system can be unpredictable — as unpredictable as the weather.

The reader should note that Figure 9 portrays only the TLR Level 2 or higher events and not each individual TLR, as a single event may have multiple TLR levels. Transaction curtailments occur at TLR Level 3 and above, so Figure 9 includes events that did not result in transaction curtailments. Furthermore, curtailment of firm demand occurs at TLR Level 5. As a result, the Figure should not be interpreted as indicating events resulting in firm demand curtailments, because these types of events are very rare.

2 – For more information regarding NERC TLR and its levels, please visit http://tlr.nerc.com

Figure 9

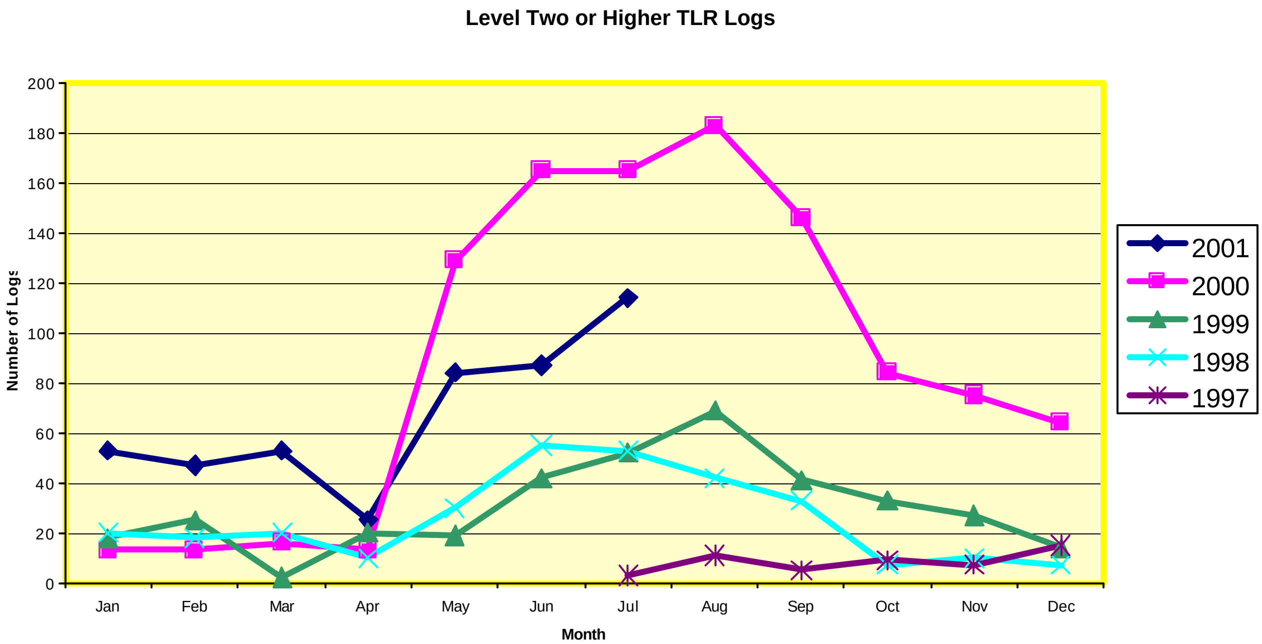

Level Two or Higher TLR Logs
Number of Logs
200
180
160
140
120
100
80
60
40
20
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
2001
2000
1999
1998
1997

Table 3 — Planned Transmission

	Transmission Circuit Miles 230 kV and Above			
	2001 Existing	2001–2005 Additions	2006–2010 Additions	2010 Total Installed
ECAR	16,137	213	43	16,393
FRCC	6,669	390	228	7,287
MAAC	7,049	58	95	7,202
MAIN	6,102	400	416	6,918
MAPP–U.S.	15,107	458	80	15,645
MAPP–Canada	5,846	209	384	6,439
NPCC–U.S.	6,456	228	5	6,689
NPCC–Canada	28,780	374	13	29,167
SERC	28,453	1,581	1,104	31,138
SPP	6,941	428	367	7,736
Eastern Interconnection	127,540	4,339	2,735	134,713
WSCC–U.S.	56,865	2,296	475	59,636
WSCC–Canada	10,824	24	93	10,941
WSCC–Mexico	431	29	–	460
Western Interconnection	68,120	2,349	568	71,037
ERCOT Interconnection	7,175	588	91	7,854
United States	156,954	6,640	2,904	166,498
Canada	45,450	607	490	46,547
Mexico	431	29	–	460
NERC Total	202,835	7,276	3,394	213,505

Construction of new transmission facilities continues to be outstripped by growth in demand and new generation additions. About 10,500 miles of transmission facility additions (230 kV and higher) are planned throughout North America over the next ten years. This amount represents only a 5.2% increase in total installed circuit miles (230 kV and higher); most of these additions are intended to address local transmission concerns or to connect proposed new generators to the transmission grid and will not have a significant impact on its capability to transfer electricity over long distances.

ERCOT has had success building new transmission, with two new 345 kV transmission projects already in service during 2001 and four more planned for 2002. ERCOT has accomplished this with the cooperation of Texas regulators who encouraged regional planning of transmission facilities in Texas.

Regional Transmission Organizations (RTOs)

FERC Order 2000

In December 1999, the Federal Energy Regulatory Commission (FERC) issued Order 2000, which directed jurisdictional entities to make filings by October 15, 2000 regarding their plans for participation in the formation of regional transmission organizations (RTOs). Existing independent system operators (ISOs) were given until January 15, 2001 to make a filing describing how they intended to comply with the requirements of Order 2000. Order 2000 further stated that the RTOs were to begin operation by December 15, 2001.

Numerous proposals were filed with FERC in response to Order 2000 and they all tended to fall into one of two primary organizational structures. One is an independent not-for-profit organization that performs the function of transmission service provider and system operator but does not own the physical transmission facilities. The other is an independent for-profit organization that not only performs the function of transmission service provider and system operator but also is the owner of the physical transmission facilities. Some proposals contain a blend of these two structures or plan to transform over time from one to the other. The map in Figure 10 shows the major RTOs proposed in response to the FERC Order 2000 based upon information available at the time this report was published. The boundaries in Figure 10 are approximate and representative. The proposed RTOs and their current status are shown in Table 4.

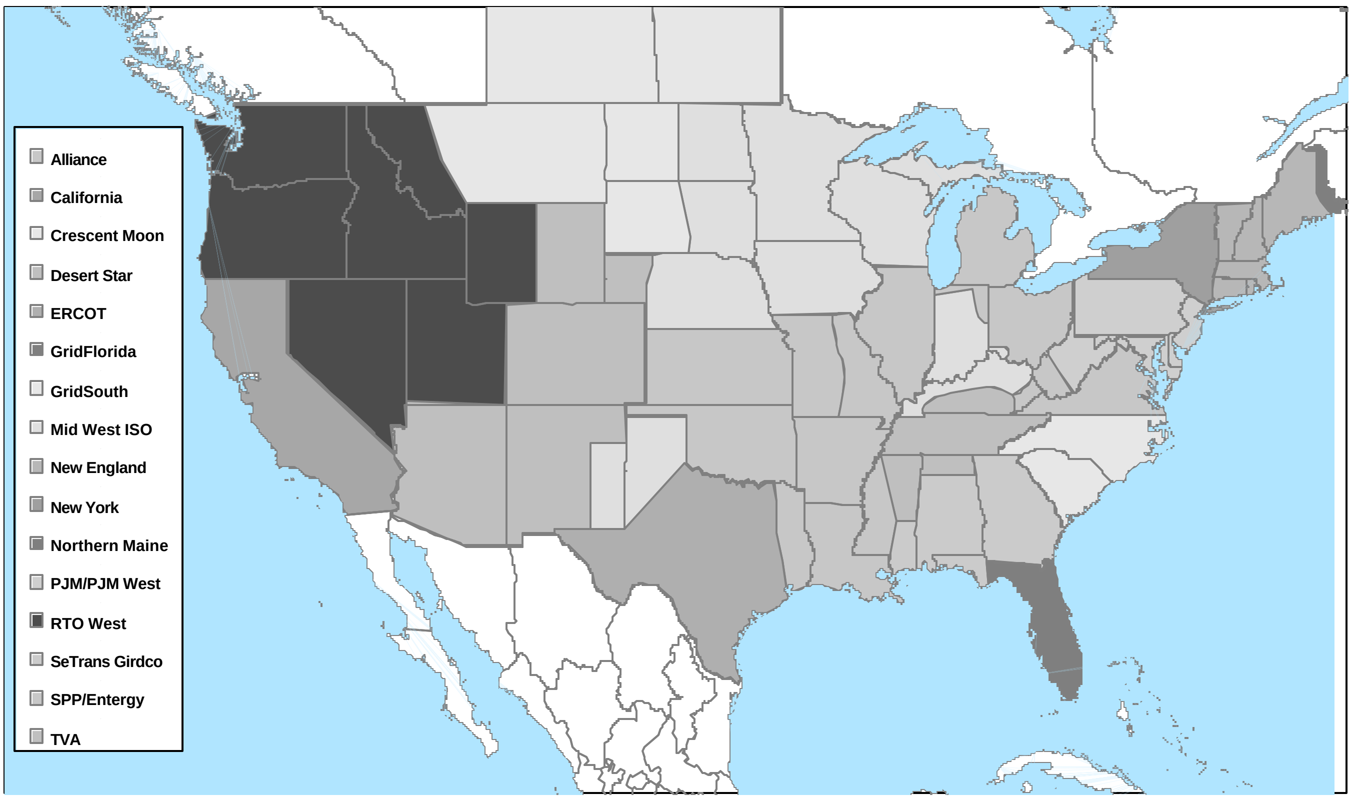
Table 4: Current Status of Proposed RTOs

RTO	Status	FERC Ruling
Alliance RTO	Conditionally Approved	Midwest
California ISO	ISO Operational/RTO Under Development	West
Crescent Moon RTO	Under Development	Midwest
Desert STAR RTO	Under Development	West
ERCOT	Operational (not under FERC jurisdiction)	Silent
GridFlorida Transco	Conditionally Approved	Option to join Southeast
GridSouth Transco	Conditionally Approved	Southeast
Midwest ISO	ISO Conditionally Approved/RTO Proposed	Midwest
New England RTO	ISO Operational/RTO Proposed	Northeast
New York ISO	ISO Operational/RTO Proposed	Northeast
Northern Maine ISA	Operational	Northeast
PJM/PJM West	ISO Operational/RTO Conditionally Approved	Northeast
RTO West	Partially Approved	West
SeTran GridCo	Denied	Southeast
SPP/Entergy RTO	Denied	Midwest/Southeast

In July 2001, FERC issued a series of orders with the objective of moving the industry closer to its goal of establishing robust United States wholesale markets and large regional RTOs. Under these orders, all existing United States RTOs and ISOs would ultimately be consolidated into one of the four (or possibly as many as six) regional RTOs, depending upon their geographic location. The four RTOs proposed by FERC are the Northeast, the Midwest, the Southeast, and the West. Table 4 identifies the most likely regional RTO for each currently operating or proposed RTO and ISO. FERC was silent regarding ERCOT, which has formed an ISO, but is not FERC jurisdictional. In recognition of Florida's unique geography, FERC has provided GridFlorida the option to remain independent or join the Southeast RTO.

Among the outstanding issues in the development of regional RTOs is the future of government-owned transmission assets, particularly the strategically located Tennessee Valley Authority, which sits between the territories of two prospective RTOs.

Figure 10



RTO Reliability Concerns

The transition period from the existing grid operating arrangements to the new world of RTO-managed grids may create some negative system reliability impacts. New systems and organizational structures will need to be implemented over very aggressive time lines. Operational and reliability issues include intraRTO congestion management procedures, transfer of security coordination responsibilities, consolidation of control areas, establishment of uniform switching procedures, etc. The scale of the responsibilities being transferred to these new organizations is unparalleled in the history of the industry. Coordination problems at the borders between RTOs (referred to as seams issues) are likely to arise as the new RTOs sort out their respective roles and the bounds of their authority. Examples of seams issues include ATC coordination, scheduling and reservation processes, business practices/tradable market products, and interRTO congestion management. It is essential that the pace of transfer of control from utilities to RTOs be managed to ensure that the reliability of the electric power systems in North America are maintained.

In the longer term, it is not clear how some RTOs will identify, execute, and pay for necessary transmission system reinforcements. Of particular concern are those reinforcements that would link neighboring RTOs. The traditional approach used in the past by utilities to justify and pay for transmission investments may not work in an RTO-managed world. New policies will be needed to ensure that necessary reinforcements are built. There is concern that the already slow pace of transmission reinforcement may stop altogether for a period while the new rules are developed. However, the pressure on the grid due to expanding trade in electric energy continues to grow unabated.

The RTOs envisioned by FERC in its July 2001 rulings have very large geographic footprints. This large size combined with the transfer of control from the local utilities to an independent entity raises a number of other concerns. Will this large size improve reliability, as has been assumed, or will local reliability needs be sacrificed to promote greater economic efficiency? Who will state regulators look to if local reliability is not being maintained and what authority will they have to correct the situation? These are questions without clear answers.

NERC and the RTOs

Another issue to be resolved is the relationship between NERC, its Regions, and the new RTOs. NERC sets standards and guidelines, while the RTOs implement the NERC standards and guidelines. According to NERC standards, operators are responsible for short-term reliability. FERC requires that, "the RTO must ensure the integration of reliability practices within an Interconnection and market interface practices among Regions." Currently, ISOs and the ten NERC Regional Reliability Councils work cooperatively and voluntarily. The existing practice of voluntary compliance with industry reliability rules continues to evolve and is moving toward rules that will become mandatory and enforceable. It is imperative that this cooperative spirit continue as responsibilities for operational reliability and planning are transferred to the RTOs.

Load Forecasting

Traditionally, load forecasts have been crucial in planning to meet the needs of vertically integrated electric utilities. A credible load forecast is necessary when planning and operating transmission and generation facilities, and in making revenue and expense forecasts to establish forecasts of financial requirements. RTOs may be responsible for reliability in the future. Even in a market environment, demand forecasts will continue to be crucial for the RTOs, load-serving entities, providers of last resort, transmission providers, transmission planners, system operators, and those responsible for assessing and maintaining reliability.

Accurate energy usage information may be more difficult to obtain. An example of this is the debate regarding the amount of demand and demand growth attributed to the expansion of the Internet. One study claims that 8% of current demand is due to the Internet. Several other experts are quoted as saying that Internet-related demand is really 1% and that Internet use is actually reducing overall demand by increasing efficiency. Other examples of uncertainties associated with load forecasting include the degree of customer responsiveness to changes in price and appliance efficiency trends. Will customer consumption patterns change in the future? Will conservation efforts (as a result of perceived energy shortages or price spikes) change over the long term? Can technical innovations for appliances be accurately predicted? The answers to these questions are not known.

Another difficulty in load forecasting comes from the increase in distributed generation and self-generation. Currently, for certain renewable generation technologies, some states allow customers to net their electricity usage against the power they supply to the grid. Customers are then assessed fees based upon their net electricity usage. If large quantities of electricity are "net metered," however, the true size of the connected demand is not known, and it is unclear to what extent the involved parties will be responsible for transmission and distribution facilities. Also, providers of last resort will need to know the connected demand, not necessarily the net demand, because there is no assurance that the renewable or other types of distributed generators will be generating electricity during peak demand periods.

Regulatory and Legislative

U.S. National Energy Policy

Shortly after President George W. Bush was sworn into office, he established the National Energy Policy Development Group headed by Vice President Cheney, whose members included key cabinet-level secretaries, administrators, directors, and policy advisors. This group assessed the energy situation in the United States and presented a set of more than 100 recommendations "to promote dependable, affordable, and environmentally sound energy for the future" as part of the National Energy Policy (NEP) to the President.

NERC has endorsed those aspects of the NEP that focus upon the reliability and adequacy of the electricity supply and delivery systems in North America. Of particular interest to NERC are the NEP's stated goals to create an industry SRRO, to increase the capability of the transmission system and to encourage fuel diversity. These actions are necessary to ensure the continued reliability of the North American electricity supply and delivery systems.

The Impact of Industry Restructuring

An important goal of the restructuring of the electric power industry is to move from "command and control" decision making for the planning and operation of generation and transmission to a de-centralized market-driven approach with the goal of achieving total lowest cost to end-users without sacrificing the current level of reliability enjoyed in North America. Although wholesale markets are not yet available in all areas of North America, where these markets are operational, some important lessons have been learned about the impacts of competitive markets upon reliability.

- A robust market can only occur if either end-use customers have the correct signals to curtail their usage voluntarily or adequate electricity supplies are available to serve all customers. An adequate supply translates into having adequate margins in both the forward market and the real-time market. Because a lack of price-responsive retail demand exists in most deregulated retail market structures, only those areas with ample generation available are most likely to benefit from early introduction of retail competition. Supply must continuously match demand to maintain secure operation.

- Markets for ancillary services have proven more difficult to develop. Reactive power cannot be transported easily on the electric transmission system. Coordinating markets for balancing energy, capacity, and regulation has proven to be a difficult task.

- Due to federal and state restructuring rules governing the separation of generation and transmission in competitive markets, generation additions cannot be planned in an integrated fashion with transmission expansion, resulting in sub-optimal transmission system expansion in some areas. Generation is not locating close to demand centers, but rather is locating close to a fuel supply, adequate cooling water, and a transmission line interconnection.

- As industry restructuring promotes the movement of bulk power over long distances, loading will continue to rise on the existing transmission systems. The transmission systems were designed by individual utilities to move energy from local generation to serve native load. They were not designed for open access and interconnection by hundreds of market participants. Industry restructuring significantly altered the nature of transmission service and the volume of such service being requested. The industry is seeing an increase in the uncoordinated simultaneous usage of common transmission facilities, such as multiple entities scheduling over the same transmission path. Evidence of such behavior can be seen in the increasing number of problems encountered by those dealing with the impacts of heavy north-to-south flows within the Eastern Interconnection and the associated thermal and voltage limitations they caused during summer 2000.

- The continued safe and reliable operation of the transmission grid depends upon proper modeling. However, the transition to a competitive electricity marketplace has hindered government and industry efforts to collect the data necessary to assemble the requisite models. In a competitive industry some information is considered confidential, proprietary, or commercially sensitive, while others view this information as falling under a public right-to-know. As facilities are utilized in the competitive market place, industry stakeholders are at odds over maintaining confidentiality, especially when the data may be released to all interested parties. A prime example is the refusal by some parties to populate NERC's Generating Availability Data System (GADS), a database of electric generator performance statistics.

Fuels

Natural Gas

Several factors have converged to make natural gas the fuel of choice for the foreseeable future. Because it is a clean burning, efficient, and widely available fuel within North America, natural gas consumption is increasing dramatically. With the projected increase in natural gas usage for electricity generation in the United States coupled with its traditional role as a home-heating and industrial fuel, total consumption by 2010 is expected to increase significantly compared to consumption levels experienced in the late 1990s. Current NERC forecasts predict that generating capacity fired by natural gas will represent over 20% of the total electric generating capability in 2009. In contrast, generators fired by natural gas accounted for less than 8% of the total electric generating capacity as recently as 1991. With this continuing growth in gas usage by the electricity sector, the adequacy and security of the natural gas supply and its infrastructure will become ever more critical to the reliability of electric supply.

In the near term, there is evidence of considerable investment activity and drilling for natural gas in North America. Following a brief decline in capital investment in natural gas in the late 1990s as prices dropped, the year 2000 has seen a doubling of upstream capital expenditures, from 27 billion dollars to 56 billion dollars. At the same time, the expenditure for land acquisition has increased by a factor of four. The figures for natural gas production through the first two quarters of 2001 have realized an increase of 2.3 and 4.3%, respectively, compared to year 2000 production figures.

The concern with the adequacy of supply of natural gas in the long term lies in the physical location of drilling. The bulk of this drilling activity is confined to known or proven reserves, which produce quick returns that are easy to capitalize at currently high prices. However, these are typically shallow wells with limited long-term capacity. Some sources of untapped long-term production, such as the Rocky Mountains, the Gulf of Mexico, and the Alaska National Wildlife Reserve (ANWR) region of Alaska, have been precluded from drilling. Continued reliance on shallow wells of limited potential will impact both the availability and price of natural gas.

Storage to meet peak winter gas requirements is improving in the near term, with storage at its highest level in five years. When compared to year 2000 levels, an increase in storage of 150 billion cubic feet has been realized, with storage being injected into salt domes and previously depleted wells.

The reliability of electric supply also is impacted by the volatility of natural gas prices, as rising prices can potentially affect not only the cost of generation but also the feasibility of planned new generator projects. Many current combustion turbine investments were planned when natural gas prices were below $3 per million Btu, and any long-term increase in the cost of gas may render these ventures no longer economically viable. Daily operation also can be impacted by natural gas prices, as very little gas is purchased via long-term firm contracts, guaranteeing supply at time of peak use. Instead, natural gas is purchased on the spot market. The generating cost during high price spikes can preclude profitable operation of a plant, particularly when that gas is purchased on the spot market. Furthermore, at plants where alternative fuels exist on site, the secondary fuel may be consumed as an economic hedge instead of being retained as an emergency, on-site, back-up fuel supply.

The gas pipeline infrastructure also must maintain its viability and integrity as the electric industry becomes increasingly dependent on the secure delivery of natural gas. The design of the pipeline system in North America does not employ the inherent redundancy of the bulk electric transmission system and, consequentially, its ability to withstand the single worst contingency. Although common hubs exist, the pipeline system in North America does not function as an integrated network such that the loss of delivery upon the interruption of one pipeline is readily assumed by other pipelines. Although some redundancy of supply is now being built into critical pipeline corridors through separate and parallel pipelines, the second path is still delivered along the same corridor and thereby exposed to a common mode event, which would interrupt the entire corridor. Thus, in many parts of North America, hundreds of megawatts of generating capacity, and in some cases thousands of megawatts of capacity, are threatened by a single pipeline contingency. Further, if such an event were to occur, the necessary notifications to the electric generator, and the resulting gas supply curtailments and reallocation would be carried out through the emergency preparedness centers of each individual state; a coordinated gas industry response is not in place.

Some aging sections of the North American pipeline system require rigorous maintenance and inspection, and recent pipeline explosions have raised public concern about the safety and environmental consequences of a catastrophic pipeline failure. Major pipeline projects such as the 425 mile Millennium Pipeline are now facing delays due to increased public scrutiny. If adequate gas supply is to be maintained in the future, the current robust pace of new construction of pipeline capacity must be maintained, and the aging of existing lines must be addressed. The alternative is the possibility of congestion facing the electric industry in the utilization of its bulk electric supply network.

Coal

In the United States, electricity production is by far the largest use for coal, with about 90% of the domestic coal production being devoted to this use. The future for coal use is tied to other factors, not the least of which is labor productivity. If labor productivity continues to improve, larger markets for coal can be expected. EIA is forecasting there will be increased coal use in the assessment period, particularly if oil prices increase. However, the growth in coal use will likely come from Western mines, which produce coal with significantly less sulfur content than most Eastern varieties. The penetration of Western coal into Eastern markets will depend upon the ability to keep transportation costs under control. The transportation problems that plagued the coal distribution system in the past few years appear to have abated. Railroads in the United States deliver over two-thirds of the total coal production. Therefore, any problems in the freight railroad community are likely to have dramatic impact on coal delivery, as occurred immediately after the Union Pacific-Southern Pacific merger.

Planning Issues

Resource Adequacy Benchmarks

In a market environment, it may be difficult to judge whether a system or region has adequate capacity. Although an assessment should be based on data and quantitative standards, the industry is finding sufficient data and standards more difficult to acquire than in the past. As a result, adequacy assessments may have become less accurate and less helpful. The data used in adequacy assessment may be inadequate and may contain uncertainties; accurate assessments depend upon accurate data. However, those market participants responsible for serving demand are not all subject to NERC authority and, due to competitive concerns, may not have an incentive to report complete information or even to provide data at all. On the supply side, new generation is constructed by developers with a national, rather than a local perspective. Those suppliers may have several projects moving forward simultaneously around the continent and may change their construction plans (e.g., expected in-service date and location) quickly to meet changes in the economy. All of this makes demand and capacity projections, even in the near term, less certain than in the past. It also suggests that a need may exist for mandatory reporting of data necessary for adequacy assessment.

For now, the industry must rely upon traditional measures (capacity margin, loss-of-load probability, unserved energy) as assessment measuring sticks. However, those adding new capacity today are making decisions based mostly upon financial objectives and not the maintenance of these traditional adequacy benchmarks. The end result will be many areas may not meet existing adequacy benchmarks in the future and the market may need to develop better indicators that track better with new capacity addition objectives.

Transmission Issues

The transmission grid was originally designed to transmit the output of the generating units over fairly short distances to local demand centers. With industry restructuring and the development of regional wholesale markets, the use of the transmission systems has drastically changed to accommodate a large volume of energy transactions over very long distances. This trend towards a dependency on the transmission grid to facilitate not only economic, but also emergency energy transactions, is expected to continue into the future.

Construction Lead Time

The lead time to construct new transmission lines combined with the economic pressures on new generation facilities to minimize the time between the start of construction and commercial operation will create many availability and reliability concerns for transmission owners and operators. In a competitive marketplace, the time required from a decision to build new generation until its completion can be less than two years. This amount of lead time may be enough for minor transmission upgrades involving only one jurisdictional entity, however, major transmission facility improvements could require five or even ten years to plan, design, license, and construct. This timing issue may prevent some new generators from delivering their full output to the market under some conditions until the necessary transmission upgrades are completed.

Alternatives to New Transmission Construction

Other approaches to address transmission system limitations and congestion must be considered. These approaches may include the construction of new generation in demand centers, the implementation of advanced transmission technologies, or economic incentives for customers to voluntarily reduce their demands. However, all of these approaches present their own challenges. Constructing new generation in urban areas will raise many of the same issues as constructing transmission lines. Securing fuel delivery to the new generation may present its own set of problems. Another area of concern is how to send the proper pricing signals to the market. New generation, new transmission technologies and economic incentives all rely upon the proper pricing of the transmission service. Therefore, regional pricing signals must be developed to drive the appropriate level of investment in alternate solutions. Those interested in system reliability may have to consider ways to encourage more innovative solutions to avoid being forced to depend on new transmission construction as the only solution for deteriorating system reliability.

Environmental Issues

The potential reliability impacts associated with environmental policy and regulatory actions depend largely on the details of their implementation, most of which are not yet known at the time of this writing. Necessary factors in assessing the potential reliability impacts of new environmental regulations include the stringency of the requirements, the length of compliance schedules, the scope of geographic applicability, coincidence with other regulatory requirements, the amount of generation needing modification and retrofit outage duration, among others.

Generating capacity additions and transmission capacity availability will be critical to supporting increasing demand as environmental regulatory requirements, particularly for existing plants, become increasingly stringent. Announcements of new generating plant capacity commitments indicate that more than 245,000 MW of new generating capacity may be operating by 2005. While not all of this capacity may actually materialize, much is already under development and is expected to significantly support increasing demand in key regional markets. The ability of new capacity to allay environmental-related reliability concerns depends on its geographic and temporal coincidence with existing plants undergoing retrofits or shutdowns. Existing generating facilities may require significant maintenance outages to install new equipment necessary to meet proposed environmental standards. The coordination of these outages will be critical to maintaining an adequate supply of electricity in North America.

Table 5 summarizes those environmental issues that may impact the future reliability of the North American electric power system, including the associated time frame — less than five years ("Immediate"), five to ten years, ("Mid-Term"), and more than ten years ("Long-Term") — and the potential impact upon reliability.

Table 5: Summary of Environmental Issues

Environmental Issue	Time Frame	Potential Changes	Potential Impact on Reliability
Particulate Matter 2.5 and 8-Hr O3 National Ambient Air Quality Standards	Mid-Term	Tighter controls on new, existing, and repowered plants; older plant closings	Moderate to High
O3 Transport	Immediate	Retrofits of NOx controls, new trading program	Moderate
Regional Haze	Mid- & Long Term	Retrofits on older pants; state plans to meet progress goals	Moderate
Plant Construction, Modification, and Maintenance	Continuing	Revisions to new source review under consideration	Moderate
Hazardous Air Pollutants	Mid-Term	Technology required all coal and oil plants	Moderate to High
Multi-Pollutant Control Strategies	Mid- & Long Term	Wholesale reworking of air pollution rules into cap & trade	Depends on cap stringency
Water Quality	Immediate, Mid- and Long Term	State rules to address TMDL; Federal standards for cooling water intake at new & existing plants	Moderate to High
Solid & Hazardous Wastes	Near Term	Consideration of wasters as non-hazardous	High
Greenhouse Gases	Mid- & Long Term	Federal plans to address CO2 from electric power industry	High

ECAR

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. There remains particular concern about the certification difficulties of American Electric Power's 765 kV project in southeastern ECAR, which is needed to guard against the potential for widespread interruptions. The Region's criteria for resource adequacy will be satisfied through 2005 if at least 3,650 MW of the announced capacity resource projects within ECAR go into service to supplement the capacity presently in service or under construction. This assumes that capacity resources are available outside the ECAR Region when needed, and that the average annual generating unit availability is maintained at or above levels experienced in recent years.

Assessment Process

In ECAR, planning for facility additions is done by the individual member company. Regional reliability assessments are performed to ensure that members' plans are well coordinated and that Regional reliability criteria are met. The ECAR Generation Resources Panel and Transmission System Performance Panel perform assessments under direction of the ECAR Coordination Review Committee. The results of these assessments are documented in reports available on the ECAR website, www.ecar.org. ECAR assessment procedures are applied to all generation and transmission facilities that might significantly impact bulk electric system reliability. These assessments consider ECAR as a single integrated system. The security impact of interactions with neighboring Regions is assessed by participation in several interregional groups such as MAAC-ECAR-NPCC (MEN), VACAR-ECAR-MAAC (VEM), and MAIN-ECAR-TVA (MET). Generation resource assessments of the ECAR systems on a Region-wide basis are performed annually for a planning horizon of up to ten years, and semi-annual assessments are made for the upcoming summer and winter peak demand seasons. Transmission assessments are performed regularly for selected future years out to the planning horizon and semiannually for the summer and winter peak demand seasons. If transmission deficiencies are discovered during this process, the member system with the deficiency is asked to explain what remedial action will be taken.

Demand

Throughout the assessment period, the peak total internal demand in ECAR is expected to continue to occur during the summer. These projected peak demands include demand that is connected to member transmission systems, even though the demand may be supplied by non-member resources. A 1.6% average annual growth rate is expected over the 2001–2010 period, with a higher average annual growth rate of 1.8% during the first five years. This peak demand growth is based on forecast economic factors and average summer weather conditions, and as such, actual peak demands may vary significantly from year to year. Current resource plans developed by ECAR members project a reliance on direct-controlled and interruptible demand management programs of about 3,400 MW by 2010. With interruptible demands and demands under demand- side management removed, ECAR's net internal demand is projected to reach 114,152 MW in 2010.

Capacity

ECAR members develop ten-year capacity plans that reflect the capacity resources necessary to reliably serve their projected demand and energy. A significant number of generation projects have been announced in the Region by members and non-members alike. Most of these announced projects are not explicitly included in members' capacity projections. When the announced capacity projects and member plans are combined, the net demonstrated generating capacity is projected to increase by 5,094 MW during 2001. The total announced increase in generating capacity is 48,927 MW by 2010. Approximately 42,300 MW of this potential capacity increase from 2001 through 2010 is in the form of combustion turbines and combined cycle plants projected to operate on natural gas.

Resource Assessment

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 include assistance from neighboring Regions, contractually interruptible demands, and direct control load management.

The construction status of many near-term capacity projects is not known until they are nearly in service, and many projects are not yet under construction. This makes for uncertainty regarding the timing and amount of new capacity additions, and consequently, the expected ECAR capacity margins. Capacity margins in ECAR that include the announced additions after 2001 range from a low of 12.8% in 2001 to a high of 32.9% in 2005, declining to 27.8% in 2010 based on net internal demand. Capacity margins without including announced additions after 2001 decline over the next ten years from a high of 12.8% in 2001 to a low of -0.3% in 2010, based on net internal demand.

The magnitude of the variation in expected capacity margins illustrates the uncertainty faced by ECAR in depending on the market to supply new generation resources, since some but not all of the announced additions are likely to be built. The analysis carried out in the ECAR assessment does not include the announced capacity after 2001, but instead indicates what amount of such capacity might be needed to achieve an acceptable level of reliability.

The ECAR assessment indicates that by 2005, there will be a need to supplement the capacity presently in service or under construction by an additional 3,650 MW. This requirement means that only a small percentage of the announced new capacity in the Region will need to be in service by 2005. This assumes that capacity resources are available outside the ECAR Region when needed, and that the average annual generating unit availability is maintained at or above levels experienced in recent years.

ECAR believes aging generating capacity will necessitate increased maintenance and lengthened outages. By the year 2010, about 76% of the capacity in ECAR in service at year-end 2000 will be 30 or more years old, and about 36% will be 40 or more years old. ECAR members recognize the challenges in maintaining the high levels of generation availability experienced in recent years. As margins decline, coordination of maintenance schedules will become more important and more difficult.

Coal is the predominant fuel used within ECAR, fueling 75% of the generating capacity in 2001. Although compliance plans to meet Phase 1 of the Clean Air Act Amendments of 1990 (CAAA) have been implemented, some uncertainty still remains in NO_x regulation compliance. Many ECAR-member companies are in the process of retrofitting selective catalytic reduction equipment (SCR) to meet NO_x compliance. Compliance dates for NO_x emissions is either May 2003 or May 2004 depending on the individual company. The potential need to extend the spring and fall planned outages between now and 2004 to accommodate these retrofits presents an additional reliability challenge for the Region.

Transmission Assessment

The transmission networks in ECAR are expected to meet adequacy and security criteria 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. The Michigan systems are in the process of completing the installation of phase-angle regulators (PAR) in the interconnections between the Detroit Edison and Ontario systems, but the PARs are not expected to have full impact until after the summer of 2001. With the PAR additions, the power flows circulating around Lake Erie that have often limited the ability of the Michigan systems to receive firm purchases from Ontario can be better controlled to improve the transfer capability between ECAR and NPCC (Ontario). Throughout ECAR, local transmission overloads are possible during some generation and transmission contingencies. However, ECAR members use operating procedures to effectively mitigate such overloads. Current plans call for the addition of about 257 miles of extra high voltage 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) 765 kV Project. This project, originally scheduled for service in May 1998 as the Wyoming to Cloverdale 765 kV line, continues to encounter certification difficulties, although some progress has been made during the past year. The earliest date that this project can be completed is now December 2004. A tri-regional assessment of the reliability impacts of this project concluded that a reliability risk exists due to its delay. Although operating procedures can minimize the risk of widespread interruptions, the likelihood of such power outages will increase until the project is completed.

Operations Assessment

Three security coordinators maintain reliability of the transmission system in the ECAR Region. ECAR MET is the security coordinator that monitors power flows between ECAR and Regions to the west and south. ECAR East is the security coordinator that monitors power flows between ECAR and the Regions to the east. ECAR North is the security coordinator that monitors power flows circulating around Lake Erie. Each of these security coordinators works with security coordinators from surrounding Regions and uses the NERC Transmission Loading Relief (TLR) procedure to maintain the reliability of the interconnected transmission network. Critical transmission interface loadings within ECAR are also monitored and controlled by ECAR members.

In addition to the NERC TLR procedure, the Reliability Coordination Plan (RCP) may be used by systems in eastern ECAR, MAAC, and the VACAR subregion of SERC to curtail or limit west-to-east transfers to ensure adequate reliability in that part of the system.

Two new control areas were certified to operate as control areas in the ECAR Region after successfully operating as conditional control areas for six months. ECAR is currently processing another request to operate a Control Area in the ECAR Region.

The East Central Area Reliability Coordination Agreement (ECAR) membership currently consists of 18 full members and 30 associate members serving more than 37 million people in a 194,000 square mile Region covering all or part of the states of Michigan, Indiana, Kentucky, Ohio, Virginia, West Virginia, Pennsylvania, Maryland, and Tennessee.

ERCOT

The year 2001 marks the start of a new operating paradigm for ERCOT. On July 31, 2001, ERCOT changed from ten separate control area operations to a single control area operation. The single control operation paves the way for the Retail Pilot Program in Texas, which allows retail customers to begin choosing new electricity suppliers. In addition, all ancillary services will be supplied to ERCOT on a competitive basis from the various generation and demand resource entities. Full retail competition is scheduled to begin January 1, 2002.

Proposals for and construction of new generation in ERCOT remain strong and the near-term generation resource requirements to meet the summer peak demands can be met from the existing generation capacity of the utilities, qualified facility cogeneration plants, and merchant power plants. New generation capacity planned or under construction will add approximately 11,000 MW between 2001 and 2002. While the majority of new resources are gas-fired, high-efficiency gas turbine combined cycle plants, approximately 200 MW of wind generation has been installed since 1998, and Texas state laws mandate 1,700 MW of generation from renewable sources be on line by 2005.

The transmission system is adequate to move energy from the generators to the demand centers for the near term. A major 345 kV double circuit transmission line from Limestone to Watermill was placed in service in May 2001. These two new circuits provide additional transfer capability for the new generation resources in the southern part of Texas to the demand centers around the Dallas-Fort Worth areas. However, in 2001, during high demand periods, a number of transmission constraints were experienced, and ERCOT Congestion Management Procedures were implemented. Future transmission required for interconnection of new generation resources and transfers of energy across the Region will be ready only if sufficient time exists to procure regulatory approval, acquire right of way, and build facilities in the time period between the commitment of the generator developer to construct and the completion of the new generation facility.

Demand and Energy

In 2000, the ERCOT area experienced a summer that was characterized by drought-like conditions and record high temperatures. As a result, the actual 2000 ERCOT summer peak demand grew to 57,606 MW from 54,849 MW in 1999, a 5.03% increase. This demand includes serving interruptible demands. For the period 1991 to 2000, the annual compound growth rate has been 4.3%.

Between 1999 and 2000, the actual ERCOT energy consumption increased from 268,534 GWh to 288,713 GWh, a 7.5% increase. For the period 1991 to 2000, the compound annual growth rate has been 3.5%.

The average annual growth rate in ERCOT's summer peak demand is projected to be 2.7% for the 2001 through 2011 period. The projected annual growth for energy is 2.7%. The forecast growth rate is based on the members' forecasts that are based on 30-year historical average temperatures rather than the extreme temperatures that have been experienced for the past three years.

While ERCOT has two direct current interconnections to the Eastern grid with a capacity of approximately 820 MW, there are no long-term sales to other Regions. There is one utility in ERCOT that is forecasting energy purchases and one utility that is forecasting energy sales outside ERCOT. The usage trend of the interconnections appears to be increasing purchases from outside ERCOT for economic rather than capacity reasons.

Assessment Process

ERCOT produces and performs the power flows analyze required to assess the reliability of the transmission system. An annual study is made to report transfer capabilities and the results of selected contingencies. The studies indicate that the interchange requirements and contingency evaluation will meet the ERCOT Planning Criteria. In 1999, all of the ERCOT subcommittees completed the conversion of the ERCOT Guides, Procedures and Criteria to be consistent with the NERC Planning Standards.

Resource Assessment

Loss-of-load-probability (LOLP) and loss-of-load-hours (LOLH) reliability studies were not conducted in 2000. ERCOT has contracted for a resource adequacy study to be performed in 2001.

The future resources that have been reported in the Capacity-Demand-Reserve Working Papers as unspecified are supported by many new proposals for new generation sources and interconnections. In the period since January 1, 1998, over 19,000 MW of new capacity has been proposed for construction in the 1999 to 2005 time frame. Due to the short time required to construct new merchant plants, ERCOT does not maintain a new generation forecast beyond 2005. While it is unlikely that all of the proposed generation will be built, the forecast for new generation continues to improve. As a result, ERCOT will not be dependent upon resources in other Regions to meet its own internal demand requirements. In addition to the plants scheduled to be built in ERCOT, several plants will be built at the border of ERCOT and SPP Regions. Two plants, totaling 1,710 MW, are connected in a manner that permits them to supply energy to ERCOT or SPP.

With the exception of 800 MW of renewable resources, all of the new plants are fueled by natural gas.

Transmission Assessment

ERCOT has approved new transmission lines to be constructed to address constraints and strengthen the bulk transmission system to accommodate new generation and increased demands. The timing of these new facilities will be important to reliability. ERCOT is currently experiencing much higher than anticipated demand growth. New generation is needed and is being proposed by the generation entities; however, timing for needed transmission again is critical.

Operations Assessment

ERCOT will experience significant changes in 2001. With the advent of retail customer choice, ERCOT will operate as one control area. ERCOT will arrange for the required ancillary services by taking competitive bids from the various supplying entities. In addition, ERCOT will implement real-time congestion management solutions if the market solution proves to be insufficient. Tests of the single control area operations were made for short periods during 2000 and early 2001 in order to familiarize market participants with the communications and operations that will be required. In addition, ERCOT continues to make daily assessments of transfer capability and security based on power flow simulations of the system that include expected outage conditions.

The Electric Reliability Council of Texas (ERCOT) is comprised of six municipal G & Ts, six cooperative G & Ts and river authorities, four investor-owned utilities, 11 independent power producers, 22 power marketers, and 13 transmission-dependent utilities. ERCOT members serve over 12 million customers (and about 200,000 square miles or 73% of Texas) and account for over 63,000 MW of generating capacity and 32,000 miles of transmission lines.

FRCC

The Florida Reliability Coordinating Council (FRCC) expects to have adequate generating capacity reserves and transmission system capability to meet the Regional reserve margin standard throughout the 2001–2010 assessment period.

FRCC members continue to operate and exchange information in an effort to maintain the reliability of the bulk electric system. As a Region of NERC, FRCC has developed a formal reliability assessment process by which a committee and working group structure is utilized to annually review and assess reliability issues that either exist or have potential for developing. This process determines what planning and operating studies will be performed during the year to address those issues. The results of these studies are utilized so that FRCC remains ready to meet the reliability needs of today's changing environment.

Assessment Process

FRCC members plan for facility additions on an individual basis. However, in addition to their own databases, they use data developed as a group under FRCC to assess the impact of neighboring systems and to adjust their plans accordingly. FRCC maintains power flow, stability, and short-circuit databases for the use of FRCC and its members.

Annually, the existing and expected conditions within the Region are reviewed, both short and long term. Recommendations are made to the FRCC Engineering and Operating Committees on the studies that should be conducted by the working groups for the next year. These reliability studies encompass Regional generation and transmission adequacy and security including import/export capabilities.

Upon completion of the reliability studies, reports including results, conclusions, and recommendations are published. Any actions taken to meet reliability criteria as a result of study report recommendations are monitored.

FRCC has also developed a compliance program to ensure member and Regional compliance with FRCC and NERC Planning and Operating Standards.

Demand and Energy

FRCC members use historical weather databases consisting of as much as 52 years of data for the weather assumptions used in their forecasting models. FRCC is historically a winter-peaking Region. However, because the Region is geographically a subtropical area, a greater number of high-demand days normally occur in the summer. Therefore, it is possible for the annual peak to occur in the summer.

The projected annual net peak demand and energy growth rates for FRCC for the next ten years are 2.4 and 2.3%, respectively, a slight increase from last year. Factors causing the increased demand growth include increased telecommunications demand and increased population growth estimates as a result of the recent census.

Resource Assessment

The reserve margins for the ten-year assessment period are well above the FRCC reserve margins reported last year for the period 2000–2009. Almost 80% of the demand in FRCC is served by investor-owned utilities (IOUs) that are required to plan to a 20% reserve margin. FRCC, as part of its overall assessment of resource adequacy, determines reserve margins for both summer and winter based on system conditions at the time of the system seasonal peaks. These system peaks are assumed to be in the months of January and August for planning and assessment purposes. The reserve margin is determined by utilizing the net of the total peak demand (which includes the projected effects of conservation) minus the effects of exercising load management and interruptible demands during the peak demand periods. FRCC members are projecting the net addition (i.e., additions less removals) of 17,604 MW of new capacity over the next ten years. Of this, 15,759 MW are projected to be natural gas-fired combined cycle units.

The increased reliance on generation that requires a short build time, such as combined cycle and combustion turbine units that burn natural gas, is evident in the assessment. This technology gives the demand-serving entities considerable flexibility in reacting to the dynamic marketplace in today's changing and competitive environment. This changing environment will continue to place more emphasis on increased efficiency of existing units. A number of the older existing units are being repowered with increased capability as combined cycle units burning natural gas. Fuel contracts are in place to meet the requirements of all existing and near-term planned generation. Contracts for long-term planned generation will be in place before the units become commercial. FRCC does not foresee any problems with fuel supply adequacy during peak periods.

There are over 600 MW of existing merchant plant capability in the FRCC Region, with an additional 314 MW scheduled to become commercial by January 2002. However, the amount that may come on line in the next ten years is dependent on a number of factors that cannot be accurately forecasted at this time. These include the results of contractual negotiations for the sale of the announced capacity, transmission interconnections and/or service requests and associated queuing issues, changes related to the advent of operations under the RTO GridFlorida, legislative or regulatory initiatives affecting merchant plants, and federal, state, and local siting requirements.

Transmission Assessment

FRCC has completed a Transmission Protection Adequacy Review Study that concludes that the interconnected transmission systems in FRCC meet the performance requirements for all contingencies studied.

A Stability Assessment of outage performance was completed by FRCC for 2001 and 2005 based on expected power imports from the Southern subregion of SERC, and found no problems.

FRCC completed a 2001 Summer Transmission Study and found that procedures such as generation re-dispatch, sectionalizing, planned load shedding, reactive device control, and transformer tap adjustments successfully mitigate all reported problems.

A Transmission Study was performed by FRCC for 2001–2010. The study showed that operational procedures such as generation re-dispatch, sectionalizing, planned load shedding, reactive device control and transformer tap adjustments successfully mitigate all the reportable demand and voltage violations appearing in the first five years. In the long term, violations of criteria can be resolved by planned transmission projects where there is adequate time to monitor trends and construct required network upgrades. None of the problems are considered significant to the reliability of the system. Individual members plan to construct 582 miles of 230 kV and 36 miles of 500 kV transmission lines during the 2001–2010 assessment period.

Interregional transmission studies are performed to evaluate the transfer capability between the Southern subregion of SERC and FRCC. Joint studies of the Florida/Southern transmission interface demonstrate there is adequate capability for additional FRCC power imports over and above the 1,845 MW currently being imported on a firm basis.

As regional transmission organizations are formed, FRCC will update processes and procedures to ensure complete transmission system assessments are performed. In fact, FRCC and GridFlorida are already working together to ensure a smooth transition to the new structures.

Operations Assessment

FRCC has both a security coordinator and an operations planning coordinator who monitor system conditions and evaluate near-term operating conditions. FRCC has a detailed security process giving the security coordinator authority to direct actions to ensure the security of the bulk electric system in the Region.

The security coordinator uses a Region-wide security analysis program and a "look-ahead" program to evaluate current system conditions. These programs use databases that are updated with data from members on an as-needed basis throughout the day. The procedures in the security process are periodically evaluated and updated to ensure Regional reliability, conformance to FRCC procedures, and adherence to NERC Standards and Policies.

The Florida Reliability Coordinating Council (FRCC) membership includes 35 members of which 12 operate Control Areas in the Florida Peninsula. FRCC *membership includes investor-owned utilities, cooperative systems, municipals, power marketers, and Independent Power Producers. The Region covers about 50,000 square miles.*

MAAC

Generation resources are expected to be adequate in the MAAC Region over the next ten years. Consistent with the MAAC Reliability Principles and Standards and in accordance with the PJM Open Access Tariff, PJM is currently evaluating generator interconnection requests for over 48,000 MW of new generating capacity expected by 2005. MAAC believes that sufficient capacity will be added to meet the MAAC adequacy objective that the probability of demand exceeding available resources will be no greater, on the average, than one day in ten years.

Based on identified system enhancements, the bulk transmission capability over the next five years is expected to meet MAAC Criteria requirements. In addition to the direct connect transmission facilities associated with new generating capacity, several transmission reinforcement projects are expected to be in service by 2005. These projects are currently being evaluated by PJM through the PJM Regional Transmission Expansion Planning Process. It is reasonable to expect sufficient transmission will be added to meet the MAAC Criteria.

New MAAC Agreement and Membership

The MAAC membership adopted a new agreement that became effective on January 1, 2001 and is available for review on the MAAC website at www.maac-rc.org. Major changes from the previous MAAC Agreement include:

- All PJM Operating Agreement signatories (199) are now automatically members of MAAC, which makes a more direct link of the MAAC and NERC reliability standards to all entities involved in PJM.
- The Administrative Board replaces the MAAC Executive Board and a MAAC Members Committee has been formed.
- An Energy Market Committee has been added to the existing Operating Committee and the renamed Planning Committee.
- An independent Compliance Monitoring and Enforcement Unit will be formed to handle NERC Standards compliance.

MAAC Assessment Process

Transmission assessments are performed regularly for selected future years out to the planning horizon (ten years), and semiannually for the pre-seasonal horizon. If deficiencies are discovered during this process, the member with the deficiency is required to describe how the problem will be resolved. The necessary reserves to remain at a loss-of-load probability of one day in ten years are calculated for the entire ten-year planning horizon every year. An agreed to reserve requirement is then set for a planning period two years into the future.

The security impact of interactions with neighboring Regions is assessed by participation in MAAC-ECAR NPCC (MEN) and VACAR-ECAR-MAAC (VEM) interregional reliability assessments.

PJM has an established, FERC approved, Regional Transmission Expansion Planning Process which ensures that the PJM, and hence, the MAAC bulk power system will be enhanced if MAAC Reliability Assessments or NERC Standards compliance deem that system expansion is necessary.

Through an agreement with Allegheny Power, the energy delivery business of Allegheny Energy, Inc. and numerous stakeholders, PJM will expand its geographical boundaries and market through the creation PJM West. This agreement will enhance the reliable operation of the bulk power transmission system while fostering the development of a more robust power market. Allegheny and PJM have requested that FERC approve the proposal by June 15, 2001, affirming that the PJM West arrangement meets all FERC Order 2000 requirements.

Demand and Energy

2001 net peak demand and energy forecasts over the next ten years have increased in comparison to the 2000 forecasts. The 2001 net peak demand growth rate has grown to 1.5%, up from 2001's 1.4%

growth rate. Geographic zone growth rates vary from 0.8 to 2.4%. The energy growth rate remains the same as last year at 1.5%.

Installed Generating Capacity Requirements

Generation resources are expected to be adequate in MAAC over the next ten years. Consistent with the MAAC Reliability Principles and Standards and in accordance with the PJM Open Access Tariff, PJM is currently evaluating generator interconnection requests for over 48,000 MW of new generating capacity expected by 2005. MAAC believes that sufficient capacity will be added to meet the MAAC adequacy objective that the probability of demand exceeding available resources will be no greater, on the average, than one day in ten years.

While it is difficult to predict how many generation projects will actually make it on line, MAAC anticipates that sufficient capacity will be added to meet the MAAC adequacy objective. This objective ensures that the probability of demand exceeding available resources will be no greater, on the average, than one day in ten years.

There are, however, two areas of concern that MAAC will continue to monitor. One concern is the possible effects of EPA regulations requiring abatement of NO_x by 2003 in all states within MAAC. The extent to which meeting these regulations results in retirement of existing generating units or long outages of existing units for capital modifications will be closely monitored and evaluated over the next two years. The second concern is the extent to which market conditions may result in off system sales of capacity and how that may affect availability of resources in MAAC, particularly during peak periods. To ensure load-serving entities have access to available capacity resources, PJM has established daily and monthly capacity markets.

Transmission Adequacy and Security Requirements

Based on identified system enhancements, transmission capability over the next five years is expected to meet MAAC Criteria requirements. In addition to the direct connect transmission facilities associated with new generating capacity, several transmission reinforcement projects are expected to be in service by 2005. These projects are currently being evaluated by PJM through the PJM Regional Transmission Expansion Planning Process. PJM evaluates all proposed transmission enhancements under this process in order to ensure that sufficient transmission will be added to meet the MAAC Criteria.

Capacity Additions and Transmission Planning

All developers who plan to install new generation or increase the capacity of existing capacity within PJM must request interconnection with the PJM transmission system and pay for any attachment facilities, local upgrades, and network upgrades necessary to accommodate the requested interconnection. Requests for interconnection are evaluated in the order in which they are received. Multiple milestones in the evaluation process allow a developer to decide whether or not to continue. If more than one generation addition causes the need to expand common equipment, the cost burden is shared.

MAAC members also rely on PJM to prepare a plan for the enhancement and expansion of transmission facilities to meet requests for firm transmission service. Based on data from the Transmission Owners and input from an Advisory Committee, PJM has the responsibility to prepare a Regional Transmission Expansion Plan that consolidates the transmission needs of the entire Region into a single plan for maintaining reliability. The Plan is subject to approval by the PJM Board of Managers.

The MAAC staff coordinates the planning of generation to meet the PJM control area peak demand. They coordinate planning of the interconnected bulk power transmission system to deliver energy reliably and economically to customers. MAAC staff also conducts many specialized planning studies as needed within the pool and with surrounding systems.

Operations Responsibilities

PJM staff forecasts, schedules, and coordinates the operation of generating units, bilateral transactions, and administers the spot energy market to meet demand requirements. To maintain a reliable and secure electric system, PJM monitors, evaluates, and coordinates the operation of over 8,000 miles of high-voltage transmission lines. The PJM OASIS is used to reserve transmission service. Operations are closely coordinated with neighboring control areas, and information is exchanged to enable real-time security assessments of the transmission grid.

PJM remains dedicated to meeting the reliability criteria and standards of the North American Electric Reliability Council and the Mid Atlantic Area Council.

PJM provides market settlement services for energy, ancillary services, transmission services, fixed transmission rights, and capacity reserve obligations.

Economy in the operation of a system, composed of numerous generators, requires that the units be dispatched in order of increasing marginal bid price regardless of their ownership or location relative to system demand. The scheduling of generation resources, interconnected by free flowing ties, and dispatched in economic merit order, results in the most economic use of resources.

Joint Maintenance Scheduling allows generator operators to perform maintenance on generating units and transmission lines in coordination with other generator operators within PJM. A coordinated maintenance plan assures reserve capability when it is needed most.

The PJM dispatch function also coordinates individual member operations to assure system security and coordination with adjacent interconnected power systems.

The Mid-Atlantic Area Council (MAAC) NERC Reliability Council serves over 22 million people in a nearly 50,000 square-mile area in the Mid-Atlantic Region. The Region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey, and Maryland, and a small part of Virginia. MAAC comprises less than 2% of the land area of the contiguous United States but serves 8% of the electrical demand. There are 199 members of MAAC.

MAIN

Introduction
MAIN does not foresee any reliability problems within its Region over the ten-year period of this assessment.

The MAIN Coordination Center (MCC) in Lombard, Illinois, is the security center as well as the OASIS node for the Region.

Demand and Energy
MAIN forecasts its summer peak demand for the 2001–2010 period to increase at an average annual rate of about 1.7%, slightly higher than last year's projected rate. The actual MAIN 2000 peak demand was 52,214 MW. Because the western area of Alliant (summer 2001 forecast demand of 3,763 MW) moved from the MAPP Region to MAIN during 2000, values from the 2000–2009 assessment are not directly comparable.

MAIN's projected average annual growth rate of electrical energy for 2001–2010 is 1.5%, the same as last year's forecast rate. Actual energy use in MAIN in 2000 was 259,600 GWH.

Resource Assessment
More than 5,400 MW of net production capacity resources are scheduled to be added within the MAIN Region in the first half of 2001. Given this large increase in capacity, long-term reserve margins for MAIN as a whole are projected to be within or exceed the recommended range of 17 to 20% (14.5 to 16.7% capacity margin). The majority of planned capacity additions in MAIN are short lead-time combustion turbine peaking units owned by Independent Power Producers, and much of their output is sold on a short-term basis.

MAIN is expected to have adequate installed generating capacity to meet its one-day-in-ten-years criterion (0.1 day or less per year LOLE). This is based on the projected yearly reserve margins for MAIN, an assumed adequate import capability and the assumption that other Regions carry on average the same level of reserves as MAIN.

Almost two thirds of existing MAIN capacity is nuclear or coal fired. These energy sources have not experienced great disruptions or price swings in the past and are expected to be dependable in the future.

Transmission Assessment
For the summer of 2001, MAIN expects import capabilities from its surrounding Regions to be adequate. The MAIN bulk electric transmission system generally appears to have no major limitations and is expected to perform adequately over a wide range of system conditions. However, parallel path flows have frequently restricted transfer capabilities into and within Wisconsin. Additionally, certain EHV facilities in southern MAIN experienced heavy loadings resulting in numerous Transmission Loading Relief (TLR) requests last year. These heavy loadings were in part due to parallel path flows occurring during large north-to-south power transfers from and across MAIN. Consequently MAIN will continue to closely monitor these EHV lines in southern MAIN and the historically constrained MAPP to MAIN interface.

For the planning horizon, MAIN expects its transmission system to perform adequately if reinforcements are installed as planned. This assessment is based on historic and current analyses used to judge compliance with NERC Planning Standards I.A.S1 through I.A.S4. All MAIN transmission owners provided assessments for their systems. Specifically, for Standards S1 and S2, most MAIN transmission owners assessed 2002 summer and 2005 summer conditions as requested by MAIN; some owners also included assessments of other time periods and in-house studies. For standards S3 and S4, MAIN made its assessment using the MAIN Future System Study for 2004 Summer conditions, the MAIN Extreme Disturbance Study for 2002 Summer Conditions, a Regional study for December 31, 1999 and assessments from in-house studies provided by MAIN transmission owners. For all four standards, the assessment was more specific for the near-term period than for the longer-term period as no marginal performance was identified in the near-term assessment and there are more uncertainties involved in longer-term simulations. However, in the future, regional reliability organization (RRO) and regional transmission organization (RTO) coordinated planning activities are expected to provide enhanced assessments of the longer-term planning horizon.

Mitigation plans, including major reinforcements that may impact the adequacy of MAIN's transmission system for the planning horizon, include the following:

- Capacitor bank additions for local area voltage support, installation of new and/or upgrade of 69 kV, 138 kV, and 161 kV lines, and installation of transformers to alleviate local loading concerns, or to improve transfer capabilities.
- 2nd Rush Island — St. Francois 345 kV line (2003)
- Weston (MAIN) — Arrowhead (MAPP) 345 kV Project (2004)
- Morgan-North Appleton 345 kV Project (2004)
- Burnham-Taylor 345 kV line (2004)
- Plano-East Branch 345 kV line (2010)

Mitigation plans impacting EHV facilities in southern MAIN are being investigated due to the parallel path flows that occur during large north-to- south power transfers from and across MAIN.

The impact of merchant generation is studied on a continuing basis by the member systems as more requests continue to come in. Uncertainties regarding these installations, as well as the formation of new RTOs and their impact on the overall planning process, offer further challenges.

Operations Assessment for 2001–2010

In the spring of 2001, each MAIN member who served native demand in the MAIN Region was audited by an independent auditor to determine the status of the member's power supply resources for meeting its expected summer demand.

Most MAIN generation owners are preparing the modifications of their units made necessary by the NO_x SIP Call. Wisconsin units have been accepted from the federal legislation. Illinois state legislators have been considering multi-pollutant control strategies for SO_2, NO_x, and mercury that may have an additional impact on the operation of coal-fired generators in that state.

The 36 Members and 8 Associate Members of the Mid-America Interconnected Network (MAIN) include 15 control areas and 29 other organizations involved in Regional energy markets. MAIN is a summer-peaking Region serving a population of 20 million in a geographic area of 150,000 square miles. MAIN encompasses portions of Iowa, most of Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin, and most of the Upper Peninsula of Michigan.

MAPP

Planned resources in the MAPP-U.S. area are judged to be inadequate to supply the forecast annual summer peak demand growth through the next ten years. When demand forecast uncertainty is taken into account, the Region may be capacity deficient by 2004 summer and nearly 5,442 MW deficient by 2010 summer. MAPP-U.S. utilities have committed to provide an additional 5,018 MW of capacity during this period. Most utilities in the Region propose to install natural gas-fired combustion turbines with short construction lead-time to meet capacity obligations.

In general, the MAPP transmission system is adequate to meet the needs of the member systems and will continue to meet reliability criteria through the planning period. Because of the tremendous increase in power marketing activity, however, the system is expected to continue to operate near its secure limit. Current studies at MAPP have also identified potential restrictions that may limit energy transfers from the Twin Cities (Minneapolis-St. Paul) area to Iowa and Wisconsin.

MAPP Assessment Process

The MAPP Reliability Council and Regional Reliability Committee direct the annual assessment of adequacy and security through the Council's working group structure. The Transmission Reliability Assessment, Composite System Reliability, and Model Building Working Groups jointly prepare the MAPP ten-year Regional Reliability Assessment. The Reliability Studies, Design Review, and Operating Review Subcommittees are committed to reviewing MAPP reliability from near-term and long-term perspectives to ensure the MAPP system can meet the needs of its members.

Demand and Energy

The MAPP-U.S. and MAPP-Canada combined 2000 summer non-coincident peak demand was 32,411MW, a 0.4% decrease over 1999, without ALTW-CIPC, and 7.3% below the 2000 forecast (34,952 MW). Alliant-West and CIPCo have moved out of the MAPP Region and into the MAIN Region.

MAPP-Canada was 1.6% above the 1999 actual demand and 7.4% below the 2000 forecast.

MAPP-U.S. accounted for 0.8% below 1999 actual demand and 7.3% below the 2000 forecast. The MAPP-U.S. summer peak demand is expected to increase at an average rate of 1.9% per year during the 2001–2010 period, as compared to 1.6% preducted last year for the 2000–2009 period. The MAPP-U.S. 2010 non-coincident summer peak demand is projected at 33,286 MW. This projection is 2.8% below the 2009 non-coincident summer peak demand predicted last year.

Annual electric energy usage for MAPP-U.S. in 2000 (145,981 GWh) was 9.8% above 1999 consumption and 1.2% above the 2000 forecast.

Resource Assessment

Generating system adequacy for MAPP-Canada will be adequate over the ten-year period. In addition, when a 3% demand forecast uncertainty is taken into account, the MAPP-Canada area will have capacity surplus of nearly 1,326 MW by 2010 summer.

The MAPP-U.S. Region is judged to be inadequate over the 2001–2010 period. Net capacity for MAPP-U.S. (committed and proposed generation additions, uprates, and retirements) will provide an additional 5,018 MW of capacity in the MAPP-U.S. area for 2001–2010. Committed and proposed capacity additions (new) account for 2,525 MW, uprates account for 2,605 MW, and retirements accounts for 79 MW. The MAPP Agreement obligates the member systems to maintain reserve margins at or above 15%, which is equivalent to a 13.04% minimum capacity margin requirement. The summer reserve margin is expected to be below the 2000 forecast and to decline from a high of 20% in 2001 to 15% in 2005 and 1% in 2010 when committed and proposed generation is considered. In addition, when a 3% demand forecast uncertainty is taken into account, the MAPP-U.S. area may be capacity deficient by 2004 summer and nearly 5,442 MW deficient by 2010 summer.

Because of the potential generating system inadequacy, MAPP must plan for additional resources and carefully watch construction lead times to ensure that enough resources will be available to maintain Regional adequacy. The ability to import power may be severely limited in the near term because of the lack of external resource availability.

Transmission Assessment

The existing transmission system within MAPP-U.S. is comprised of 7,239 miles of 230 kV, 5,742 miles of 345 kV, and 342 miles of 500 kV transmission lines. MAPP-U.S. members plan to add 229 miles of 345 kV and 605 miles of 230 kV transmission in the 2001–2010 time frame. The MAPP-Canada existing transmission system is comprised of 4,578 miles of 230 kV and 130 miles of 500 kV transmission lines. MAPP-Canada is planning for an additional 59 miles of 230 kV transmission in the 2001–2010 time frame.

MAPP member systems continue to plan for a reliable transmission system. Coordination of expansion plans in MAPP takes place through joint model development and study by the Regional Transmission Committee. This committee includes transmission owning members, transmission-using members, power marketers, and state regulatory bodies. The Transmission Planning Subcommittee, in cooperation with the five subregional planning groups, has prepared the MAPP Regional Plan, 2000 to 2009, to address the needs of all stakeholders.

In general, the MAPP transmission system is judged to be adequate to meet firm obligations of the member systems provided that the local facility improvements identified in the ten-year transmission plan are implemented. However, MAPP continues to monitor the thirteen transmission constraints within the Region that limit MAPP exports. Current studies at MAPP have identified potential restrictions on the transmission system for outages of certain 345 kV tie lines connecting the Twin Cities metropolitan area of Minneapolis-St. Paul to Iowa and Wisconsin area, such as Prairie Island-Byron or King-Eau Claire. These outages may result in system stability restrictions that continue to limit energy transfers from the Twin Cities to Iowa and Wisconsin.

A transmission system limitation was recently identified in the eastern North Dakota-northern Minnesota area that will limit the ability to meet firm obligations in and through the area during winter peak conditions. A study is currently being conducted that will identify and recommend transmission system alternatives.

MAPP has seen a tremendous increase in power marketing activity resulting from open access and available low cost energy in the Region. This high level of activity has stretched the existing transmission system to its reliability limits to take advantage of market opportunities. MAPP members will continue to take a proactive role in the planning and operation of the system in a secure and reliable manner.

Operations Assessment

The MAPP Security Center has been fully operatonal with the implementation of real-time system monitoring of key flowgates, data collection at five-minute intervals, and near real-time pre-contingency analyses of system conditions. MAPP member systems jointly perform interregional and intraregional seasonal operating studies under the direction of the Operating Review Subcommittee to coordinate real-time operations. Subregional operating review working groups have been formed to deal with day-to-day operational issues such as unit outages and scheduled transmission system maintenance. The MAPP Reserve Sharing Pool continues to provide a benefit to the Region through the sharing of generation during system emergencies.

The Mid-Continent Area Power Pool (MAPP) membership includes 104 utility and non-utility systems. The MAPP Region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area is 900,000 square miles with a population of 18 million.

NPCC

To ensure continued resource adequacy, NPCC participants must continue to realize planned merchant capacity. The near-term challenge is to ensure the timely synchronization of this expected capacity, and to fully integrate this new generation into the transmission network.

Resource Assessment Process

The Northeast Power Coordinating Council has in place a comprehensive resource assessment program directed through NPCC Document B-08, "Guidelines for Area Review of Resource Adequacy." This document charges the NPCC Task Force on Coordination of Planning (TFCP) to conduct periodic reviews of resource adequacy for the five NPCC Control Areas: the Maritimes Area (New Brunswick Power, Nova Scotia Power, Inc., and the Maritime Electric Company Limited), New England (ISO New England Inc.), New York (New York ISO), Ontario (Independent Electricity Market Operator), and Québec (Hydro-Québec). In undertaking each review, the TFCP will ensure that the proposed resources of each NPCC Area will comply with NPCC Document A-02, "Basic Criteria for Design and Operation of Interconnected Power Systems." The Area must successfully demonstrate:

- its resource adequacy criterion and how it is applied,
- resource requirements to meet the criteria for the time period under consideration
- interconnection assistance considered in determining its requirement, and
- how its resource criteria meet the NPCC criterion of "… probability of disconnecting non-interruptible customers due to resource deficiencies, on the average, will be no more than one day in ten years."

To focus on the timely installation of capacity requirements, each area conducts an interim assessment of resource adequacy on an annual basis. A more comprehensive resource review is conducted on at least a triennial basis, and it is conducted more frequently as changing conditions may dictate.

The primary objective of the NPCC area resource reviews is to identify those instances in which a failure to comply with the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems," or other NPCC criteria, could result in adverse consequences to another NPCC area or areas. If, in the course of the study, such problems of an inter-area nature are determined, NPCC informs the affected systems and areas, works with the area to develop mechanisms to mitigate potential reliability impacts and monitors the resolution of the concern.

Demand and Energy

Among the five NPCC control areas, the Canadian entities (the Maritimes Area, Ontario, and Québec) are winter-peaking systems. The average annual demand growth rate through the winter of 2010–2011 for the Canadian members of NPCC is projected to be 1.1%, unchanged from the 2000 forecast. The projected annual electrical energy growth rate through 2010 is 1.2%, also unchanged from 2000 forecasts.

The average annual demand growth rate forecast for the summer-peaking United States entities of NPCC (New England and New York) through the summer of 2010 is 1.3%, as compared with the 1.2% projected in the 2000 forecast; the forecast annual electrical energy growth rate through 2010 is 1.2%, unchanged from 2000 projections.

Area Resource Assessment

New England

New England will meet the NPCC Resource Adequacy Criterion of one-day-in-ten-years loss-of-load-expectation (LOLE) through 2010 if future generating capacity additions are fully integrated into the New England transmission system, assuming normal demand expectations area experienced. New England also projects adequate resources to meet its reliability criterion through 2005 assuming a high demand growth scenario. Beyond 2005, contingency plans will be called upon should this high demand growth occur. If partial integration is assumed, and a 50% derating of these new generating resources is modeled to reflect transmission constraints, New England system reliability could be below the one-day-in-ten-years LOLE criterion by the year 2006.

New York

Given current demand projections, New York will meet the NPCC criterion of one-day-in-ten-years Loss of Load Expectation (LOLE) through 2010 with the expected installation of approximately 7,200 MW of new generating capacity by 2004.

An installed reserve of 18% of peak demand is required to meet the NPCC reliability criterion of one day of interruption per ten years. The New York State Reliability Council reassesses the installed reserve margin each year. Existing capacity within NY and known purchases and sales with neighboring control areas provide sufficient capacity to meet the 18% installed reserve margin for the year 2001. Beyond the year 2001, NY is showing a deficiency in the capacity reported to meet the 18% installed reserve margin. It is anticipated that the resources necessary to meet the required installed reserve margin will be procured through the installed capacity market of the NYISO. Currently, there are approximately 6,590 MW of new capacity within the New York State Article X process that has been included in the installed reserve margin calculation of the NYISO. The NYISO has included only those facilities that have an approved Article X application. The New York State Article X process approves the required licensing for new capacity within New York. An additional 6,500 MW (approximate) of additional capacity that was not included in the NYISO's installed reserved margin calculation is in the pre-application stage of the Article X process. Additionally, part of the New York installed capacity market design allows Special Case Resources (for example, distributed generation and interruptible load customers that are not visible to the NYISO Market Information System) to participate in the installed capacity market. These customers thus become another source of capacity for the load-serving entities.

The New York ISO imposes locational capacity requirements on load-serving entities located within two localities in New York as described in the "Locational Installed Capacity Requirements Study", NYISO, February 15, 2001. These defined localities are New York City and Long Island. The load-serving entities within these localities must procure a percentage of their capacity requirement from resources located within the locality, and these locational capacity requirements are expressed as a percentage of the forecasted peak demand for the locality. The New York City locational capacity requirement is 80% of the demand level, and the locational capacity requirement is 98% of the demand level within the Long Island locality. The timely integration of proposed merchant activity, of which there is currently more than 10,000 MW of pending applications, within these localities is essential to meeting these resource requirements.

Ontario

Ontario's ten-year demand forecast has an average annual energy growth rate of 1.2% over the forecast period compared with last year's forecast of 0.9%. The forecast is based on weekly normalized weather derived from 30-years of historical weather data.

Ontario expects to be in compliance with the NPCC Resource Adequacy Criterion of one-day-in-ten-years loss-of-load-expectation (LOLE) for the ten-year forecast period. The aggregate amount of new merchant capacity projected to come on line in the next ten years is about 6,000 MW. Under median and high growth scenarios, a range of 2,000 to 3,000 MW of additional capacity is expected to be required in the latter half of the forecast period.

Québec

For the near term, Québec projects adequate reserves to comply with the NPCC LOLE criterion of one-day-in-ten-years for the near term. Beyond 2005, over 2,500 MW of uncommitted hydroelectric capacity continues to be studied, and proposals are now being put forward.

Maritime Area (New Brunswick, Nova Scotia, and Prince Edward Island)

A reserve criterion for the Maritime Area is 20%, and adherence to this criterion is demonstrated to comply with the NPCC reliability criterion. As a result of the Sable gas fields, the Maritimes Area of NPCC now projects increasing usage of natural gas for electricity generation throughout the study period, and, in some years, actually reducing projected electric consumption as heating load transfers to natural gas.

Transmission Assessment

The existing interconnected bulk electric transmission systems in New England, New York, Ontario, Québec, New Brunswick, and Nova Scotia meet NPCC Criteria and are expected to continue to do so throughout the forecast period. For the ten-year period through 2010, currently planned transmission within NPCC includes 63 circuit-miles at the 230 kV voltage level, 527.2 circuit-miles at the 345 kV voltage level, 88 circuit-miles at the 735 kV voltage level, and 362 circuit-miles of HVDC construction.

The reinforcement of the Michigan-Ontario interface is nearing completion with the addition of phase-angle regulating transformers (PARs) to the Scott-Bunce 230 kV circuit and the two Lambton-St. Clair 345 kV circuits. Together with the existing phase-angle regulator transformer in the Keith-Waterman 230 kV circuit, these enhancements will result in full control of the interface within the range of the PARs, permitting the distribution of power flows over the individual interconnections to nearly match their ratings and increasing the thermal capability of the Michigan-Ontario interface by almost 400 MW. Failures of the PARs in circuits L4D and L51D have delayed operation until late in the autumn of the year 2001 at the earliest. The Presidential Permit granting permission for the operation of the Ontario-Michigan phase angle regulators was granted on April 19, 2001, citing accepted utility practices for their operation as developed by the Lake Erie Security Process Working Group.

Major transmission proposals currently being proposed within NPCC include:

- A new 1,250 MW interconnection between Ontario and Québec consisting of a 230 kV two circuit line starting at the Hawthorne station and ending at a new Outaouais Converter Station in Québec. The in-service date is June of 2003, however, it could be delayed, depending on regulatory approvals.

- A new 990 MW interconnection between Ontario and a location to be determined in either Pennsylvania or Ohio. The expected in-service date is the second quarter of 2004.

- A second interconnection between the Point Lepreau station in New Brunswick and Orrington, Maine. Construction of this line will increase the net interchange capability between the Maritimes and New England by a minimum of 300 MW, and, by allowing a south to north flow of energy, it will virtually eliminate the Minimum Tie Flow requirement currently associated with the Keswick-Orrington Line 3001. The facility is scheduled for completion in 2003.

- A proposed HVDC interconnection between Norwalk, Connecticut, and Hempstead Harbor, New York that would allow transmission of up to 660 MW of electricity in either direction. An in-service date of May 2004 is projected.

- The Neptune Project, a merchant electricity transmission project proposed by the Neptune Regional Transmission System, designed to bring power from Canada and the Mid-Atlantic Region to New England and New York. The Federal Energy Regulatory Commission granted conditional approval to the project in July of 2001. The Neptune project, to be developed in four stages, would link 1,200 MW interconnections in New Jersey and Maine with interconnections in Boston, New York City, Long Island, and Connecticut. Ultimately, the project would allow transmission of 3,600 megawatts of power from Maine and Canada to the northeast as well as another 1,200 MW of power from the PJM Interconnection to New England and New York.

To further the coordination of interregional transmission assessment, NPCC is 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 under the auspices of the Joint Interregional Review Committee, composed of representatives from ECAR, MAAC, NPCC, and VACAR.

The ISO-NE, the NY ISO, the IMO and PJM also take part in the ISO Memorandum of Understanding to pursue enhanced interregional coordination and system planning.

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 three Canadian Control Areas, the New York ISO, and the ISO New England Inc. 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.

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. TransÉnergie, New York ISO, Independent Electricity Market Operator (Ontario), and ISO New England Inc. serve as the security coordination centers for NPCC. As such, each will exchange necessary security data through the Interregional Security Network (ISN). Further, NPCC routinely conducts weekly operational planning calls between control area operators to coordinate short-term system operations. NPCC establishes procedures for the exchange of security information discussed in these regularly scheduled, prearranged conference calls.

The NPCC emergency conference call mechanism is a tool that augments the regular conference call process to enable operational security entities in NPCC and neighboring Regions to communicate current operating conditions and facilitate the procurement of assistance under emergency conditions. These calls may be initiated upon the request of any NPCC Control Area System Operator and are coordinated by NPCC staff. NPCC has also established a Memorandum of Understanding on area Emergency Assistance to facilitate Area response to either a forecast or actual shortage of operating reserves. Through this Memorandum of Understanding, coordination will be ensured with neighboring Areas, and clear and efficient communications with participants in all Regional markets will be established. The objective of the process will be to maximize reliance on the marketplace to provide emergency support, and, accordingly, to therefore minimize the need for emergency transactions between the control Areas.

Ontario and New York, together with other Lake Erie companies, participate in the Lake Erie Emergency Redispatch (LEER) procedure. The objective of this procedure is to facilitate emergency redispatch among participants within the Lake Erie control areas to relieve transmission constraints that could otherwise result in the requirement of another Lake Erie company to shed firm load. It is thus implemented only when firm load curtailment is imminent. The LEER procedure was originally approved by FERC on May 12, 1999, and the Lake Erie Security Process Working Group has continued to refine the security tools used to activate the LEER procedure to ensure they continue to meet the needs of the Lake Erie system operators. A modified filing was made by the LEER Participants to proceed with control room adoption of revised procedures to become effective July 31, 2000, and the Commission granted its retroactive approval to the revised LEER Agreement on September 15, 2000. The revised LEER Agreement strengthens the language contained in the 1999 filing citing NERC Policy compliance and adds the clarity and specificity required to address the questions raised by FERC and the interveners during the initial filing. The revised LEER Agreement further:

- Clarifies that LEER does not transform a non-firm transaction into a firm transaction, since the protecting transactions are not afforded a priority greater than the remaining Firm Point-to-Point transactions.

- Specifies that the LEER group has agreed to reserve and "Tag" protecting transactions as non-firm hourly transmission service.

- Clearly points out that the protecting transactions may be susceptible to NERC Transmission Loading Relief (TLR) cuts due to constraints on other flow-gates, and, should a protecting transaction be curtailed by NERC TLR actions, the protected transaction will also be curtailed.

NPCC is a voluntary, non-profit organization. Its current membership, of which there are thirty-seven, represents transmission providers, transmission customers, and ISOs serving the northeastern United States and central and eastern Canada. Also included are three non-voting memberships extended to regulatory agencies with jurisdiction over participants in the electricity market in northeastern North America as well as public-interest organizations expressing interest in the reliability of electric service in the Region. The geographic area covered by NPCC, approximately one million square miles, includes the state of New York, the six New England states, and the provinces of Ontario, Québec, New Brunswick, and Nova Scotia.

SERC

The Southeastern Electric Reliability Council (SERC) expects to have adequate generating and transmission capacity to supply the forecast peak demand and energy requirements throughout the ten-year assessment period. Nearly 39,616 MW of new generating capacity are planned to be added in the Region over the next ten years. Approximately 30,000 MW or 76% of this planned generation is expected to be natural gas fueled simple cycle or combined cycle combustion turbines. Planned transmission additions include approximately 2,800 miles of new 230 kV and 500 kV transmission lines.

Assessment Process

The adequacy and reliability of the interconnected SERC systems are evaluated annually by the Reliability Review Subcommittee (RRS) of the SERC Engineering Committee (SERC-EC). Data for this analysis is provided to SERC by its members. The RRS maintains a listing of reliability studies; recommends new reliability studies deemed necessary; reviews SERC reliability criteria (along with the SERC Planning Standards Working Group); acts as liaison between SERC-EC and other groups within SERC and NERC; and serves as a clearinghouse for the exchange of information.

Demand and Energy

Forecasts of peak demand and energy are developed based on historical weather conditions and assume the use of load management and interruptible contracts at the time of the annual peak. The ten-year forecast average annual growth in summer peak demand is 2.2%. This is slightly less than last year's forecast growth rate of 2.4%. The growth rate over the last ten years averaged 3.4%. The amount of load management available during the forecast period ranges from 8,403 MW to 7,868 MW.

The forecast growth rate in energy usage is 2.1%, down slightly from last year's forecast of 2.4%. The historical growth rate for the last ten years was 3.1%.

Resource Assessment

Planned generation additions within SERC for the ten-year period are 39,616 MW. These additions include 12,109 MW of simple cycle combustion turbines, 17,929 MW of combined cycle plants, and 9,578 MW of various other types of generation. Because of the short lead times associated with combustion turbine and combined cycle plants, most of the planned capacity additions are currently uncommitted. In SERC, as in many other regions of the country, a significant amount of merchant power plant capacity is expected to be built within the next ten years. Based on a survey conducted by SERC and information collected by EPSA, roughly 20,000 MW of merchant capacity targeted for completion in SERC is in various stages of development. Of course, the amount of that capacity which will actually be built is highly dependent on factors such as market prices; the ability to arrange suitable interconnection and transmission access agreements; the number of other merchant plants that are being constructed; the ability of the company to obtain financial backing; and other typical business factors.

Spot coal prices have increased significantly since last year. This signals a tightening of supply as the electricity produced by coal continues to increase. Natural gas has also seen dramatic increases in price as the so-called "gas bubble" has dissipated. The planned increase in gas-fueled generation will require significant increases in gas supply and pipeline capacity. At this time, fuel supply in SERC is expected to be adequate.

The reported SERC capacity margins for the ten-year period range from 10 to 13%. The average capacity margin over the ten-rear period is 12%. These margins are slightly higher than last year's reported margins. SERC believes that planned capacity will be sufficient to provide adequate and reliable service for forecast demands.

Generation Plant Development in SERC

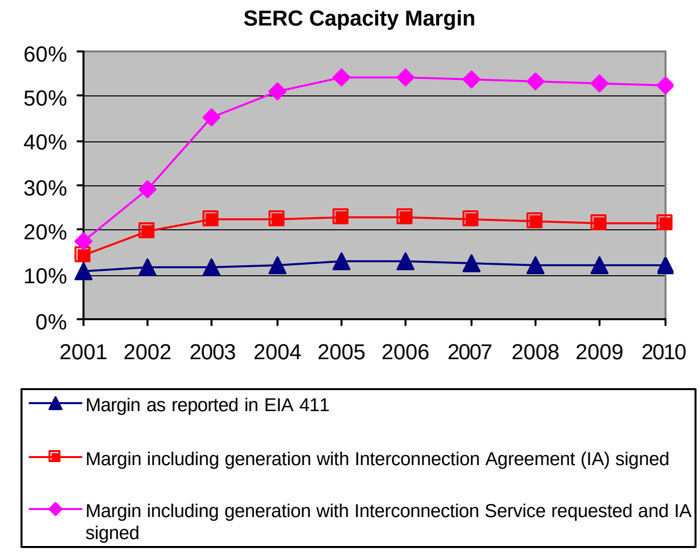
SERC conducts a survey each year to identify the amount of generation that is under development in the Region. The 2001 survey requested that all generation development within SERC to be reported, regardless of its ownership. The survey was directed to the transmission owners (TO) within SERC. Since generating plant developers must have an agreement with a TO prior to moving power on the transmission network, SERC felt that the TOs would be the best source of information for this survey. Respondents were asked to report projects according to their stage of development as measured by the level of interconnection service (i.e., interconnection service has only been requested through the OASIS process, interconnection service agreement has been signed, or the project has been designated as a network resource). The subregions coordinated responses to avoid double counting.

A summary of the survey responses is contained in the following table:

Table 2.1.1 SERC Generation Development 2001–2010

Current Status of Generation Plant Development	*In-Service Year of Added Generation (MW)									
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Interconnection Service Requested Only	6,242	20,291	57,210	39,123	24,170	2,315	2,160	310	465	620
Interconnection Agreement Signed	7,623	9,077	8,506	0	0	0	0	0	0	0
Designated as Network Resource	5,612	6,612	6,983	3,679	802	1,185	1,522	390	550	390
Totals	**19,477**	**35,980**	**72,699**	**42,802**	**24,972**	**3,500**	**3,682**	**700**	**1,015**	**1,010**

The survey indicates a total of 19,477 MW of generating capacity is under various stages of development in SERC for 2001. This amount almost doubles for each of the next two years before it begins to decrease. The majority of development was reported for the first five years and totals over 195,000 MW. The generation development activity is significantly less in the final five years reported. This decline is probably more of an indication of the planning horizon for such generation plants and not that this time period will be void of generation development. The potential impact on SERC capacity margins is shown in the figure below.



Transmission Assessment

The existing bulk transmission system within SERC is comprised of 19,222 miles of 230 kV, 784 miles of 345 kV transmission lines, and 8,447 miles of 500 kV transmission lines. Planned transmission additions include 2,415 miles of 230 kV and 369 miles of 500 kV lines over the next ten years.

SERC is directly interconnected with the transmission systems in ECAR, FRCC, MAAC, MAIN, and SPP. Transmission expansion plans in SERC are coordinated by joint modeling efforts among member systems and with these interconnected Regions. Results of Regional and interregional studies demonstrate that the SERC transmission systems meet NERC and SERC reliability criteria and should have adequate capability to supply forecast demand and energy requirements under normal and contingency conditions. Interregional transfer studies indicate that the ability to transfer power above contractually committed uses has become marginal on some interfaces. This is a reliability concern because it impacts the geographic diversity of external resources that can be called upon during emergency import scenarios that may result from large unit outages.

Operations Assessment

Heavy north-to-south electricity transfers into the SERC Region over the last two summers have caused significant voltage depression and concerns that voltage stability limits may be exceeded. Recent studies have the maximum simultaneous north-to-south power transfer that can be supported while ensuring system reliability. Results of these studies will be used by system operators and security coordinators to monitor system conditions and to ensure that maximum transfer limits are not exceeded. In addition, SERC and NERC are working together to update transfer limits as conditions change.

Entergy Subregion

The Entergy subregion 2000 system peak was 27,714 MW. This demand is approximately 4.4% higher than the 1999 actual peak of 26,558 MW. The 2000 actual peak was 6.9% above the forecast peak for 2000 of 25,927 MW. The forecast average demand growth rate is 1.71% for the Entergy subregion throughout the next ten years. The 2001 forecast peak for the Entergy subregion is 27,085 MW.

The Entergy subregion projects approximately 2,687 MW of new capacity resource additions in the next ten years. Of this 2,687 MW, AECI has planned 105 MW combined cycle and 1,117 MW combustion turbine capacity additions for 2001–2010. Approximately 195 MW of the capacity increase is due to nuclear capacity additions (uprates), and 1,264 will be net capacity purchases. The remainder is fossil-fired steam generation.

Reported capacity margins in the Entergy subregion are below 8% for the ten-year period. However, at the time of this writing, over 21,000 MW of merchant generators have signed interconnection agreements with Entergy Corporation, alone. This generation has not been reported in the subregional totals. It is reasonable to expect that a significant portion of this generation will be available to serve demand in the Entergy subregion, and in the remainder of SERC. As a result, capacity in the Entergy subregion should be adequate to supply forecast demand.

The Entergy subregion operated approximately 2,300 miles of 230 kV, 750 miles of 345 kV, and 2,100 miles of 500 kV transmission in the year 2000. AECI added 4.3 miles of 345 kV transmission during the year 2000.

Transmission interfaces to the north are expected to continue to be impacted by loop flows during summer 2001. Joint studies with neighboring control areas and Regions continue to investigate possible solutions and operational restrictions to preserve system reliability under such conditions.

Southern Subregion

The Southern subregion experienced a system peak hour demand during the summer of 2000 of 43,692 MW. This demand was approximately 3.5% above the 1999 actual peak of 42,196 MW. A 2.93% average annual demand growth rate is forecast over the next ten years for the Southern subregion. This rate of growth is slightly lower than the historical 4.05% average peak demand growth rate. All companies within the subregion utilize a scenario process in demand forecasting.

The Southern subregion projects a resource capacity increase of 9,533 MW from 2001 to 2005 and 8,120 MW from 2005 to 2010. These values reflect unit retirements, changes in capacity purchases and sales, and new resource additions. The majority of capacity additions during the reporting period are combined cycle units (11,346 MW) and combustion turbines (5,966 MW). Reported capacity margins in the Southern subregion range from 11 to 16% over the ten-year period.

The Southern subregion has 7,010 miles of 230 kV and 1,980 miles of 500 kV transmission currently in service. During the 2001–2010 reporting period, an additional 1,439 miles of 230 kV and 284 miles of 500 kV transmission are planned. A large number of new generators have applied for interconnection in the Southern subregion. Interconnection studies have shown major stability problems, which result in large portions of the system pulling out of synchronism. The solution to these stability problems will require major transmission system improvements.

TVA Subregion

The TVA subregion experienced a summer peak hour demand of 29,446 MW during the summer of 2000. This demand was approximately 3.7% higher than the 1999 summer peak demand of 28,397 MW, and was about 1.6% lower than the forecast peak. The TVA subregion 2000 summer peak demand represents an all-time system peak demand. The

TVA subregion is forecast to experience an average annual summer peak demand growth rate, including load management, of 1.79% over the next ten years. This is a decrease from the 2.19% growth rate reported last year. The amount of contractual interruptible demand forecast for the subregion ranges from 2,356 MW in 2001 summer, to 2,492 MW in 2010 summer.

Resource additions, in combination with interruptible demand arrangements, are planned to maintain a capacity resource margin generally around 12.5%. The 2001 capacity resource margin projection averages 12.5% over the ten-year period, which is comparable to the 2000 average.

Generation resources within the TVA subregion include a diverse mixture of hydroelectric, coal, nuclear, pumped storage, and gas turbine units. Coal and nuclear-fueled generation continues to be the primary energy supply for the subregion, accounting for 66% of the reported capacity in 2001. For 2001, the Tennessee Valley Authority reported the planned addition of 616 MW of natural gas-fired peaking capacity, the long-term purchase of 440 MW from an IPP within the subregion, and various unit upgrades totaling 89 MW. A net total of 5,167 MW of additional capacity is projected over the 2002–2010 time period to meet peak demand growth in the TVA subregion. Approximately 1,800 MW of merchant capacity was operational in the subregion as of January 1, 2000. Although the output of these merchant plants may at times be utilized to help meet the demand in the subregion, the long-term contractual status for the output of these plants was unknown at the time of this report. Merchant capacity additions are not currently reflected in the reported data.

The TVA subregion bulk transmission network consists of transmission lines operated at 115 to 500 kV. The majority of the network consists of 161 kV (10,600 miles) and 500 kV (2,400 miles) facilities that transmit power from generation sites to demand centers within the subregion. There are 31 miles of 230 kV and above transmission line additions planned for the TVA subregion during the next ten years. A number of 161 kV improvements are also planned during this period, but are not reported in the EIA 411 data.

Transmission assessment studies indicate that a heavy dependence on "market purchases" from resources physically located outside the subregion will bear a degree of risk based on transmission constraints. Recent operating experience and planning studies have increased awareness of the impacts on the TVA bulk transmission system that result from large-scale imports into SERC. On the other hand, the impact of increasing merchant plant capacity interconnecting in SERC, tilting the supply/demand balance, will provide significant challenges to modeling and analysis of transmission system performance.

VACAR Subregion

The VACAR 2000 summer non-coincident peak demand was 55,236 MW. This peak was 8.1% greater than the forecast demand of 51,083 MW with load management in effect, and 3.4% more than the forecast demand of 53,441 MW without load management in effect.

Current demand projections indicate a 2.07% annual growth rate in summer peak demand. This is lower than the 2000 forecast annual growth rate in summer peak of 2.11%. The actual growth in summer peak demand since 1991 has been 2.8%. Demand side management programs may or may not have been activated during the actual peak demand periods. This could lead to larger variations in the actual demands reported. It is projected that 2,575 MW of load management will be available within VACAR for the period 2001–2010. Projected peak demand for the 2001 summer is 58,175 MW without load management and 55,600 MW if load management is initiated.

For the 2000 summer period, the VACAR subregion had installed generating capability of 58,739 MW. Projected installed generating capability for the 2001 summer period is 61,043 MW. This represents an anticipated increase of 2,304 MW over the 2000 summer peak season. This data includes only planned capacity resources, and does not include planned resource purchases. Capacity purchases for the period 2001–2010 are projected to be 2,526 MW in 2001 and 4,099 MW in 2010. These values also represent the maximum and minimum projected purchases for the ten-year reporting period.

During the ten-year period, 14,289 MW of capacity is planned to be added within the subregion. The majority of this capacity (76% or 10,888 MW) are combustion turbines and combined cycle generating units. A breakdown of planned capacity additions reveals 6,478 MW of combined cycles and 4,410 MW of combustion turbines. The projected capacity margins for the ten-year period range from 11 to 14%.

As of the end of 2000, the VACAR subregion had a total of 2,001 circuit miles of 500 kV and 9,889 circuit miles of 230 kV transmission lines in service. Throughout the 2001–2010 period, VACAR presently plans to construct 85 miles of 500 kV transmission lines and 576 miles of 230 kV transmission lines.

Southeastern Electric Reliability Council (SERC) membership includes 35 members and 31 associate members. The SERC Region includes portions of 13 states in the southeastern United States, and covers an area of approximately 464,000 square miles. SERC is divided geographically into four diverse subregions that are identified as Entergy, Southern, Tennessee Valley Authority (TVA), and the Virginia-Carolina Area (VACAR).

SPP

SPP will have adequate generation capacity over the short term with committed capacity meeting targeted reserve margins. Beyond the short term, meeting the target margins will be highly dependent on the ability of the market to provide the necessary generation resources.

The bulk transmission system is adequate to provide reliable service to native load for the short term. For the long term, it is somewhat difficult to assess the bulk transmission system because of the large number of proposed merchant power plant additions in and around SPP. The bulk transmission study performed recently showed marginally adequate transmission to handle transfers out of or across the Region. Should merchant power plant development continue, transmission will not be adequate to handle extensive exports required to deliver the new power to markets outside SPP. From the time of a commitment made by a generator to SPP for transmission service, the remaining time required for completion of the generation project is often less than the lead time required for the construction upgrades necessary to provide transmission service, in some cases much less.

Demand and Energy

SPP is a summer-peaking Region with projected annual peak demand and energy growth rates of 2.1 and 1.7%, respectively, over the next ten years. Members continue to forecast similar growth of future demand and energy requirements compared to previous years. These growth rates are consistent with the ten-year historical growth rates of SPP.

Members are focusing more on the short term (two to five years), thereby shortening the planning horizon. This reduces the long-term (five to ten years) forecast accuracy. The projected growth rates for peak demand and energy over the next five years are 1.6 and 1.5%, respectively. The actual growth rates for peak demand and energy over the last five years were 2.3 and 2.1%, respectively.

Resource Assessment

SPP Criteria requires members to maintain a 12% capacity margin. Expected capacity margins reflected in EIA-411 data are 14.4% in 2002, 14.4% in 2003, and 13.0% in 2004. The capacity margins remain steady at around 11.3% until 2008 when it begins to decline to 9.5%.

If information on uncommitted purchases, sales, and capacity additions are excluded from the EIA 411 Report and only very certain capacity additions are included, the expected capacity margins are 12.6% in 2002, 12.3% in 2003, and 8.9% in 2004.

Regarding capacity margins beyond 2003, SPP members, for the most part, are assuming that the market will provide needed resources, or that new, presently uncommitted capacity sources will be made available to those members within a two- or three-year time period.

The EIA-411 information does not reflect some 13,000 MW of merchant plant additions, which are expected to come on line during the 2002 to 2006 time period.

The amount of current merchant plant activity is in stark contrast to that of just two years ago. Many of the proposed plants are completing permitting and starting construction. The prospect for available merchant plant additions to assist in maintaining the required capacity margin is very good.

These merchant plant additions would significantly increase the above-mentioned capacity margins. This increase is approximately 1.7% for each 1,000 MW of the merchant plant capacity that is added. For example, if all of these merchant plant additions were made as planned, capacity margins for the 2002–2004 period would be between 18.2 and 20.2%. In addition, only a small percentage of the planned merchant plant capacity would need to be completed in order to increase the above stated 11.3% capacity margins for 2005–2008 to the 12% minimum required capacity margin.

Transmission Assessment

Only a few transmission facilities additions of Regional significance are planned for the bulk transmission system over the next ten years. The additions being planned primarily benefit local areas and have minor impacts on subregional or Regional transfer capability. The planned transmission facilities of Regional significance include:

- 345 kV interconnection between the northern and western subregions of SPP in 2001 that increases the transfer capacity between these subregions as well as between SPP and MAPP;
- 200 MW HVDC interconnection between SPP and WSCC in 2004; and
- substantial additional transfer capacity within the West Central subregion of SPP in 2006.

For the purposes of OASIS posting of Available Transfer Capability (ATC), transfer capability studies are performed on the bulk transmission system hourly for the next 168 hours, daily for days 8–31, and monthly for months 2–16 based on a sliding 16-month window. These calculations account for the most restricting credible contingencies as recognized by each member company and/or the Regional transmission provider.

The bulk transmission system meets applicable NERC and Regional planning standards for this sliding study window. In addition to the 16-month sliding ATC studies, SPP has evaluated the general reliability of the power transmission network in accordance with NERC requirements. Measures 1 and 2 of the NERC compliance standards have been completed for the 1–5 year time frames. The SPP transmission owners have provided mitigation plans where examination of the power transmission network has identified base case and/or (n-1) conditions producing Regional violations of reliability criteria. The 6–10 year assessment is slated to be completed in a similar manner.

SPP is also currently in the process of completing a coordinated bulk EHV study of the transfer capability of the power transmission network. The study has focused on the cross-Regional power transfer capability of the power transmission network examining the 2001, 2004, and 2006 summer peaks. These studies indicate that the SPP transmission network has ability to support imports to a greater extent than exports. Overall, the SPP transmission network is strongest in handling cross- Regional power movement originating from the Iowa/Nebraska interconnections (MAPP) down through the interconnected systems of the southern part of the Region (SERC). SPP generation interconnection procedures are utilized to address the issues of lead time for adding transmission to accommodate new generation and the needs of the merchant developers regarding transmission planning studies to determine the transmission additions needed to tie their planned generating plants into the bulk transmission system. In some cases where extreme amounts of transmission additions are required to serve the total planned capacity of new generation, other alternatives may be needed to meet the needs of both the transmission provider and the merchant developer.

In addition to providing merchant developers with an orderly means of approaching a transmission owner, consistent methodology and Regional requirements will enhance the transmission analysis to ensure Regional transmission reliability.

Operations Assessment

SPP has operated a security center since 1997 and is the security coordinator for the SPP Region. The security center, located at the SPP offices, provides the exchange of near real-time operating information and around-the-clock security coordination.

SPP implements security procedures required of a NERC security coordinator under NERC Operating Policies. SPP coordinates maintenance outage schedules of the generation and transmission facilities within the Region. Security analysis is performed daily to help members recognize heavy line loading that is expected to occur. When heavy line loading occurs in real-time or is expected to occur in near real-time, NERC Transmission Loading Relief (TLR) procedures are invoked to relieve facility loading. A major tenet of these procedures is to ensure that TLR is achieved by real changes in generation patterns, not a mere shuffling of interchange schedules. These procedures have provided for TLR in SPP and surrounding Regions. SPP has experienced TLR curtailments on its transmission facilities in recent years and expects that this will continue in the future. Although SPP has adequate transmission to reliably serve native load, it expects heavy use of the transmission system for economy transactions to continue into the future.

SPP, currently consisting of 50 members, serves more than 4 million customers and covers a geographic area of 400,000 square miles containing a population of over 18 million people. SPP's diverse membership consists of 13 investor-owned utilities, seven municipal systems, seven generation and transmission cooperatives, three state authorities and one federal government agency, one wholesale generator, and 17 power marketers. Seventeen of the 150 control areas within the North American continent are members of SPP. SPP members have more than 350 electric industry employees in various organizational groups that bring together unmatched expertise to deal with tough reliability and equity issues. An administrative and technical staff of approximately 100 persons facilitates the organization's activities and services. Primary offices are located in Little Rock, AR and a branch office is located in Hilliard, OH.

WSCC

The projected capacity margins and fuel supplies are not anticipated to be adequate to ensure reliable operation in all areas of the Region during the first year of the 2001–2010 ten-year period. The expected capacity inadequacies for the summer of 2001 are thoroughly addressed in the WSCC 2001 Summer Assessment report. The report is available on the WSCC website (www.wscc.com). Adequacy thereafter will depend largely on the timely construction of significant amounts of proposed new generation. The capacity margin adequacy over the next ten years assumes the timely construction of approximately 66,849 MW of net new generation, which is up dramatically from the 30,200 MW reported last year. The capacity margin adequacy also assumes average weather conditions. If multiple areas peak simultaneously, portions of the Region may need to issue public appeals for customers to reduce their electricity consumption, and other measures may be instituted as necessary to ensure that adequate operating reserves are maintained. The transmission system is considered adequate for firm and most economy energy transfers.

WSCC Assessment Process

The evaluation of reliability within the WSCC Region is performed using a comprehensive annual assessment process based on the following established reliability criteria:

- Power Supply Design Criteria;
- Minimum Operating Reliability Criteria; and
- Reliability Criteria for Transmission System Planning.

Adherence to these criteria provides an objective and deterministic evaluation of the reliability (adequacy and security) of the western interconnected system.

Resource Assessment

The resource assessment process in the WSCC Region has been in place for many years and is prepared for the four subregions of WSCC. A resource assessment on a Region-wide basis is not appropriate because of transmission constraints.

Resource adequacy is assessed by comparing the sum of the individual member reserve requirements (determined by criteria) for a subregion with the projected reserve capacity. WSCC is currently refining its resource adequacy assessment practice in light of the changing electric industry.

At present, the projected reserve capacity (margin) is determined by subtracting the firm peak demand, exclusive of interruptible and controllable load management peak demand, from the net generation and firm transfers. Net generation and firm transfers are determined exclusive of inoperable capacity. If the projected reserve capacity margin exceeds the reserve requirement, it is expected that projected resources are adequate for the subregion. On this basis, projected reserve capacity is not expected to be adequate throughout the WSCC Region for the 2001 through 2010 ten-year period. The assessment assumes that approximately 66,849 MW of net new generation will be built when and where needed. WSCC's enhanced assessment methodology will place additional emphasis on transmission limitations between assessment areas within WSCC.

Transmission Assessment

The member systems' transmission facilities are planned in accordance with the "WSCC Reliability Criteria for Transmission System Planning," which establishes performance levels intended to limit the adverse effects of each member's system operation on others and recommends that each member system provide sufficient transmission capability to serve its customers, to accommodate planned inter-area power transfers, and to meet its transmission obligation to others.

Each year WSCC prepares a transmission study report that provides an ongoing reliability-security assessment of the WSCC interconnected system in its existing state and for system configurations planned through the next ten years. The disturbance simulation study results are examined relative to the "WSCC Reliability Criteria for Transmission System Planning." If study results do not meet the expected performance level established in the criteria, the responsible organizations are obligated to provide a written response that specifies how and when they expect to achieve compliance with the criteria. Other measures that have been implemented to reduce the likelihood of widespread system disturbances include: a southern island load tripping plan, a coordinated off-nominal frequency load shedding and restoration plan, measures to maintain voltage stability, a comprehensive generator testing program, enhancements to the processes for conducting system studies, and a reliability management system (described in more detail below).

The WSCC Region has established a process that is used to verify compliance with established criteria. The process is summarized below with the key components to be monitored in this process:

- Compliance Monitoring

  A voluntary peer review process through which every operating member is reviewed at regular intervals to assess compliance with WSCC and NERC operating criteria. Control areas are reviewed once every three years.

- Annual Study Report

  In accordance with WSCC policy, the system will not be operated under system conditions that are more critical than the most critical conditions studied.

Security assessment shall be an integral part of planning, rating, and transfer capability studies.

- Project Review and Rating Process

  Study groups are formed to ensure project path ratings comply with all established reliability criteria.

- Operating Transfer Capability Policy Group Process

  Operating studies are reviewed to ensure that simultaneous transfer limitations of critical transmission paths are identified and managed through nomograms and operating procedures. Four subregional study groups prepare seasonal transfer capability studies for all major paths in a coordinated subregional approach for submission to WSCC's Operating Transfer Capability Policy Group.

NORTHWEST POWER POOL AREA

The Northwest Power Pool (NWPP) Area is comprised of all or major portions of the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada, and Utah; a small portion of northern California, and the Canadian provinces of British Columbia and Alberta. Over the period from 2000 through 2010, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 2.0 and 1.8%. With a significant percentage of hydro generation in the region, the ability to meet winter peak demand is expected to be adequate for the next ten years. The ability to meet sustained seasonal energy requirements over the ten-year period is dependent on new generation additions. Resource capacity margins for this winter-peaking area range between 20.9 and 26.7% of firm peak demand for the next ten years.

Northwest power planning is done by sub-areas. Idaho, Nevada, Wyoming, Utah, British Columbia and Alberta individually optimize their resources to meet their demand. The Coordinated System (Oregon, Washington, and western Montana) coordinates the operation of its hydro resources to serve its demand. The Coordinated System hydro operation is based on critical water planning assumptions (currently the 1936–1937 water year). Critical water in the Coordinated System equates to approximately 11,000 average megawatts of firm energy load carrying capability. Under average water year conditions, the additional non-firm energy available is approximately 3,000 average megawatts. The 2001 actual January through July Volume Runoff (Columbia River flows) at The Dalles, Oregon was 58.2 million acre-feet (Maf), or 54.9% of the thirty-year average. This was the second lowest water year the northwest has experienced since record keeping began. Coordinated system hydro reservoirs refilled to the lowest levels seen in almost a decade. The water fueling associated with hydro powered resources can be difficult to manage because there are several competing purposes including but not limited to: electric power generation, flood control, biological opinion requirements resulting from the Endangered Species Act, as well as special river operations for recreation, irrigation, navigation, and the refilling of the reservoirs each year. Any time precipitation levels are below normal, balancing these interests becomes even more difficult.

Agreement has been reached among United States federal parties involved in the operation of the Columbia River Basin concerning river operations for a period of ten years. This agreement is embodied in the Biological Opinion of 2000. However, this agreement is subject to reopening by the parties. These include the National Marine Fisheries Service, the U.S. Fish and Wildlife Service, the U.S. Bureau of Reclamation, the U.S. Army Corps of Engineers, and the Bonneville Power Administration (BPA). The net impact of the present agreement is a reduction in generating capability as a result of hydro generation spill policies designed to favor migration of anadromous fish. The agreement includes provision for negotiating changes in the plan under emergency conditions, as it was done this past year.

In view of the present overall west coast conditions, including the extreme water conditions, analyses indicate the Northwest region will be able to meet firm loads and required forced outage reserve with no additional margin for the 2001–02 winter. This only after extraordinary measures were taken with respect to buy-down of industrial demands, aggressive public conservation, the acquisition of generation from "portable" diesel and natural gas combustion turbines, and suspending some non-power operations on the hydro system. The result of these extraordinary measures and the economic down turn has resulted in approximately 8% reduction in power needs as compared to demand in 2000.

Generation integration study requests totaling substantial capacity have been received by BPA and other transmission providers and are being processed. The future adequacy of the generation supply over the next ten years in the NWPP region will depend on how many among these and future proposals are actually built. Generally these generation facilities will have a relatively short time to completion once the decision is made to go ahead. These factors combine to make it difficult to forecast generation adequacy with any certainty for an extended period.

In view of the longer time required for transmission, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goal of allowing anticipated transfers among NWPP systems and serving interconnection needs under most conditions through 2010. This includes addressing several areas of constraint within Oregon, Washington, and other areas within the Region as well as integration of new generation.

One such example is the Puget Sound area of the state of Washington where transmission is insufficient to meet all firm commitments for area use with transfers to British Columbia during significant outages. Utilities in the area are working together to identify ways to increase system transfer capability. System reinforcements are being implemented to meet forecasted firm commitments that include load service in Puget Sound and return of the Canadian Entitlement to British Columbia. Plans are being developed for implementation this summer to assure adequate ability to curtail transmission use during periods of constrained capacity.

The capability to import power into the Pacific Northwest during low probability extreme cold weather periods continues to be an important component of the transmission grid. In order to support maximum import transfer capabilities the Northwest has been depending on tripping of Direct Service Industry (DSI) demand as a remedial action for loss of the Pacific Interties. If these transfer capabilities are to be supported this winter, it would have to be through the tripping of firm loads, since the DSI load has been depleted by buy downs. Reductions of DSI demands through buy downs also affect transfer levels from Montana into Washington. If the drought continues, it may be extremely advantageous to maximize transfer capabilities to reduce reservoir drafts and aid reservoir filling.

The Northwest has developed an Emergency Response Plan to address an immediate power emergency should it occur and an Adequacy Response Process to avoid a power emergency by promoting regional coordination and communications. Several state agencies are working with all interested parties (utilities, city governments, etc.) on curtailment planning and communications.

BPA and eight investor-owned utilities are working together to prepare a filing for a regional transmission organization known as RTO West in the NWPP area. The filing for RTO West is to be submitted in two stages; the first was filed in October 2000 and the second stage is expected to be filed with FERC by March 2002. If approved by FERC, implementation could begin as early as 2003.

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 2000 through 2010, peak demand and annual energy requirements are projected to grow at an annual compound rate of 2.0%. Summer resource capacity margins range between 18.0 and 25.9% of firm peak demand for the next ten years.

Significant amounts of generation were installed in the RMPA in 2000. Xcel Energy (Xcel - parent company of Public Service Company of Colorado) built or purchased 391 MW of new generation in 2000. Front Range Power plans on adding 460 MW of gas-fired generation in the Colorado Springs area by spring 2003. Xcel is also purchasing or constructing 322 MW that will be online by June 2001. A significant portion of that generation (235 MW) will be sited at Midway substation (Colorado Springs area) so that voltage support from the units will be available to enhance area reliability. In addition, Xcel plans to add 294 MW in 2002, 635 MW in 2003, and 585 MW in 2004. All these are planned as gas-fired turbines. Platte River Power Authority is adding 80 MW of gas-fired generation in 2002, 2003, and 2004 for a total of 240 MW. The new generation Project includes a Rawhide-Timberline 230 kV line and upgrades to some existing 115 kV lines in the Loveland/Fort Collins area to meet projected peak demand. Black Hills Power & Light has a planned addition at the existing Wyodak generation complex of an 80 MW gas-fired turbine by June 2001 and 80 MW of coal-fired generation at the Ygen plant in 2003. Two Elk Power Partners is planning on adding a 250 MW waste coal plant in east central Wyoming by 2003.

Tri-State Generation and Transmission Association, Inc. is constructing a major 230 kV line from Walsenburg, Colorado to Gladstone Substation in northeast New Mexico. The planned in-service date is 2003. Xcel plans on constructing a new Midway-Daniels Park 230 kV line by 2004. The North American Power Group has proposed a new 345 kV line called the Powder River-Denver Project from east central Wyoming to the Front Range of Colorado. The planned in-service date is 2007. The rebuild of the Pawnee-Story 230 kV line and several other projects including upgrading current transformers, circuit breakers, and line switches coupled with removal of existing line wave traps no longer in use has allowed an increase in transfer capability from southeastern Wyoming to northeast Colorado from 1,509 MW to 1,588 MW. This path is known as Path 36 or TOT3.

In June 2001, Xcel will finish construction of a major 230 kV transmission line from Fort St. Vrain to Green Valley Substation northeast of Denver to increase import capability to the Denver area. West Plains Energy is installing a 100 MVA 230/115 kV autotransformer near Canon City, Colorado in the spring of 2003. The transformer will provide backup support for the Canon City area as well as increased voltage support to this area.

Hydroelectric generation is expected to be well below normal in the northern Rocky Mountains, and slightly below normal in the central Rocky Mountains. Water inflows into the South Platte, North Platte, Colorado, Big Thompson and Green Rivers are expected to be considerably below normal in 2001 as snowpack is between 60–80% of normal in these river basins. Water inflows into the Missouri River are expected to be approximately 60% of normal this year. Reservoir storage is below normal and hydroelectric generation is expected to be below the long-term average. The Glen Canyon power plant is operating under environmental constraints, with no seasonal steady flow test expected this summer. The associated release limitations reduce peaking capability, but the plant will be able to respond to short-term emergency conditions.

ARIZONA-NEW MEXICO-SOUTHERN NEVADA POWER AREA

The Arizona-New Mexico-Southern Nevada Power Area consists of Arizona, most of New Mexico, the westernmost part of Texas, southern Nevada, and a portion of southeastern California. Over the period from 2000 through 2010, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 3.3 and 3.4%. Resource capacity margins for this summer-peaking area range between 10.0 and 20.1% of firm peak demand for the next ten years. The ability to meet sustained seasonal energy requirements over the ten-year period is dependent on new generation additions.

A few transmission projects have been reported for the subregion that will increase transfer capability and improve reliability. These projects include a 115 mile 230 kV interconnection from Walsenburg Substation in southeastern Colorado to a new 230/115 kV substation at Gladstone, New Mexico. This line is scheduled to enter service in 2003. An additional line from the Palo Verde 500 kV Switchyard to the Estrella Switchyard in the Phoenix area, the Palo Verde-Southwest Valley 500 kV line, is scheduled for completion in 2003. Transmission projects scheduled to enter service in 2004 include a 395 mile 500 kV line from Shiprock, New Mexico to Marketplace, Nevada and a 230 kV line from the San Juan generating plant to the city of Farmington, New Mexico. An additional 345 kV connection between generating facilities in northern New Mexico and a substation in central New Mexico is under investigation, with a possible in-service date of 2006. Prior to this new transmission line being in service, the current carrying capability of the parallel 115 kV transmission lines will be upgraded.

Generation integration study requests totaling substantial capacity have been received by the Arizona-New Mexico-Southern Nevada transmission providers and are being processed. New generation proposals have focused on the Arizona and southern Nevada areas where approximately 17,000 MWs of IPP development is proposed with in-service dates ranging from 2002 to 2004. With the importance of Palo Verde as an energy marketing and trading hub, a large number of requests have been received for interconnection of new generation facilities (and related transmission) at the Palo Verde bus and/or its associated transmission system. In order to accommodate all of the requests (approximately 10,000 MW), the Palo Verde owners are constructing a satellite Palo Verde 500 kV switchyard, named Hassayampa, adjacent to the existing Palo Verde switchyard. The Hassayampa switchyard will accommodate interconnection requests for generation projects being sited close to the Palo Verde generating facility. Nevada Power Company is proceeding with the development of a 500 kV project centered at its Harry Allen site that will integrate 3,000 MW of new IPP generation into the Nevada Power control area and adjoining control areas. The planned project in-service date is June 2003.

As with other areas within WSCC, the future adequacy of the generation supply over the next ten years in the Arizona-New Mexico-Southern Nevada region will depend on how many among these and future proposals are actually built. Generally, these generation facilities will have a relatively short time to completion once the decision is made to proceed. These factors combine to make it difficult to forecast generation adequacy with any certainty for an extended period of time.

In association with these Arizona generation proposals, several Arizona utilities have embarked upon a regional EHV transmission study to evaluate developing transmission alternatives in the Central Arizona area. The study is called the Central Arizona Transmission System (CATS) study and encompasses an area bounded by environs between the Phoenix and Tucson metropolitan areas and the Palo Verde Nuclear Generating Station. The purpose of the study is to evaluate what high-voltage transmission facilities are needed in the long term to, among other things, improve the use of the existing transmission system for future demand growth in the Phoenix and southern Arizona areas, increase the power transfer capability between the Phoenix and Tucson areas, facilitate future generation additions south of Phoenix and north of Tucson, and provide additional transmission capacity to and from the Palo Verde energy trading and marketing hub. The CATS study will provide a framework for the participating utilities to plan and coordinate transmission lines and receiving stations in the area. The study will also identify how the timing and phasing of projects can be done in a coordinated manner.

Significant amounts of shunt capacitors and series compensation are being installed along with implementation of additional direct under-voltage load shedding schemes to preserve reliability in the area. In addition, the major generating plant operators in the area participate in the Southwest Reserve Sharing Group. This group shares contingency reserves, using a computer-assisted communication system for activating reserves in the form of emergency assistance to recover from generation outages in the area within the ten-minute recovery criteria.

In response to the restructuring of the electric utility industry, the Southwest utilities are investigating the feasibility of creating an RTO to be called DSTAR (Desert Southwest Transmission and Reliability Operator). DSTAR's stakeholder development process is following the FERC Order 2000 RTO prescription. The draft DSTAR FERC filing calls for operation of DSTAR on December 31, 2002.

Due to the energy situation in California, the New Mexico Electric Utility Industry Restructuring Act delays the separation of generation from transmission and distribution and the provision for customer choice for schools, universities, colleges, residential, and small business customers from January 1, 2001 to January 1, 2007 and from July 1, 2002 to July 1, 2007 for all remaining customers.

CALIFORNIA-MEXICO POWER AREA

The California-Mexico Power Area encompasses most of California and the northern portion of Baja California, Mexico. Restructuring of the electric industry in California has added much uncertainty to future adequacy projections of generating capacity, energy production by independent power producers, and effects of customer energy efficiency/demand-side management programs. Recognizing that future forecast uncertainty exists, peak demands and annual energy requirements are currently projected to grow at respective annual compound rates of 2.6 and 2.8% from 2000 through 2010. Projected resource capacity margins range between 10.2 and 34.5% of firm peak demand for the next ten years.

A severe heat wave in California in 1998 resulted in numerous curtailments of service to interruptible customers, California experienced additional load curtailments in 2000. These two experiences demonstrate that even with the assumptions of future generation and transmission expansion projects, statewide and local reliability problems exist in the short term.

Western Systems Coordinating Council (WSCC), with 97 members, 13 affiliate members, and eight commission members, encompasses about 1.8 million square miles in 14 western states, two Canadian provinces, and a portion of Baja California Norte, Mexico. Extremes in population and demand densities, in addition to long distances between demand centers and electric generation sources, characterize the Region. The Region is subdivided into four areas: the Northwest Power Pool Area, which is winter peaking and heavily dependent on hydroelectric generation (63% of installed capacity); the Rocky Mountain Power Area, which can be either summer or winter peaking with a 13% hydroelectric and 65% coal-fired generating capacity mix; the Arizona-New Mexico-Southern Nevada Power Area, which is summer peaking with a 15% nuclear and 39% coal-fired generating capacity mix; and the California-Mexico Power Area, which is summer peaking and heavily dependent on gas-fired generating units (51% of installed capacity).

Reliability Assessment Subcommittee

Edward P. Weber
Subcommittee Chairman
Transmission System Planning
Western Area Power Administration

George R. Bartlett
Subcommittee Vice Chairman/OC Liaison
Director, Transmission Operations
Entergy Services, Inc

Charles A. Roteck
ECAR Representative
Manager, Transmission Planning & Protection
FirstEnergy Corporation

Kent Saathoff
ERCOT Representative
Director of Technical Operations
ERCOT

John E. Odom, Jr.
FRCC Representative
Manager, Transmission Planning
Florida Power Corporation

Laura J. Manz
MAAC Representative/MIC Liaison
Manager, Transmission Planning & Technical Services
Public Service Electric and Gas Company

Donald R. Carlson
MAIN Representative
Manager, Energy Supply and Control
Wisconsin Public Service Corporation

Hoa Nguyen
MAPP Representative
Power Supply Coordinator
Montana–Dakota Utilities Co.

John G. Mosier, Jr.
NPCC Representative
Director, Operations
Northeast Power Coordinating Council

Robert Gibbons
Canadian Member-at-Large
Manager, Long Term Forecasts and Assessments
Independent Electricity Market Operator

Verne B. Ingersol, II
SERC Representative
Manager, Regional Planning
Carolina Power & Light Company

Jay Caspary
SPP Representative
Manager, Engineering
Southwest Power Pool

Chris Oakley
WSCC Representative
Director, Power Supply
West Kootenay Power

John J. Conti
DOE Liaison
Acting Director, Office of Economic, Electricity & Natural Gas Analysis
U.S. Department of Energy

Samantha Slater
IPP Representative
Manager of State and Regional Affairs
Electric Power Supply Association

K. R. (Chuck) Chakravarthi
IOU Representative
Manager, Interconnection & Special Studies
Southern Company Services, Inc.

Tom Hallam
FRCC Alternate
Staff Engineer
Florida Reliability Coordinating Council

Glenn Catenacci
MAAC Alternate
Staff Engineer
Public Service Electric and Gas Company

Ed Riley
WSCC Alternate
Director of Regional Coordination
California Independent System Operator

Jeff Mitchell
ECAR Alternate
Director of Regional Coordination
East Central Area Reliability Agreement

Timothy R. Gallagher
Staff Coordinator
North American Electric Reliability Council